2015 OASDI Trustees Report

2. Estimates as a Percentage of Gross Domestic Product

This section contains long-range projections of the operations of the theoretical combined Old-Age and Survivors Insurance and Disability Insurance (OASI and DI) Trust Funds and of the Hospital Insurance (HI) Trust Fund, expressed as a percentage of gross domestic product (GDP). While expressing fund operations as a percentage of taxable payroll is a very useful approach for assessing the financial status of the programs (see section IV.B.1), expressing them as a percentage of the total value of goods and services produced in the United States provides an additional perspective.

Table VI.G4 shows non-interest income, total cost, and the resulting balance of the combined OASI and DI Trust Funds, of the HI Trust Fund, and of the combined OASI, DI, and HI Trust Funds, expressed as percentages of GDP on the basis of each of the three alternative sets of assumptions. Table VI.G4 also contains estimates of GDP. For OASDI, non-interest income consists of payroll tax contributions, proceeds from taxation of benefits, and reimbursements from the General Fund of the Treasury, if any. Cost consists of scheduled benefits, administrative expenses, financial interchange with the Railroad Retirement program, and payments for vocational rehabilitation services for disabled beneficiaries. For HI, non-interest income consists of payroll tax contributions (including contributions from railroad employment), up to an additional 0.9 percent tax on earned income for relatively high earners, proceeds from taxation of OASDI benefits, and reimbursements from the General Fund of the Treasury, if any. Cost consists of outlays (benefits and administrative expenses) for insured beneficiaries. The Trustees show income and cost estimates on a cash basis for the OASDI program and on an incurred basis for the HI program.

The Trustees project the OASDI annual balance (non-interest income less cost) as a percentage of GDP to be negative throughout the projection period under the intermediate and high-cost assumptions, and to be negative for all years except 2079-88 under the low-cost assumptions. Under the low-cost assumptions the OASDI annual deficit as a percentage of GDP decreases through 2019. After 2021, deficits increase to a peak in 2033, decrease through 2053, increase again through 2070, and decrease through 2078. Annual balances are positive from 2079 through 2088 and negative thereafter. Under the intermediate assumptions, annual deficits decrease from 2015 to 2017, increase through 2038, decrease from 2038 through 2050, and mostly increase thereafter. Under the high-cost assumptions, annual deficits increase throughout the projection period.

The Trustees project that the HI balance as a percentage of GDP will be positive throughout the projection period under the low-cost assumptions. Under the intermediate assumptions, the HI balance is negative for each year of the projection period except for 2016-21. After 2021, annual deficits increase through 2045, decline through 2063, and remain relatively stable thereafter. Under the high-cost assumptions, the HI balance is negative for all years of the projection period. Annual deficits reach a peak in 2075 and decline slowly thereafter.

The combined OASDI and HI annual balance as a percentage of GDP is negative throughout the projection period under both the intermediate and high-cost assumptions. Under the low-cost assumptions, the combined OASDI and HI balance is negative through 2016, positive from 2017 through 2029, negative from 2030 through 2033, and then positive and mostly rising thereafter. Under the intermediate assumptions, combined OASDI and HI annual deficits decline from 2015 through 2017, increase from 2017 through 2040, and decrease through 2053. After 2053, annual deficits generally rise, reaching 1.96 percent of GDP by 2089. Under the high-cost assumptions, combined annual deficits rise throughout the projection period.

By 2089, the combined OASDI and HI annual balances as percentages of GDP range from a positive balance of 0.87 percent for the low-cost assumptions to a deficit of 6.39 percent for the high-cost assumptions. Balances differ by a much smaller amount for the tenth year, 2024, ranging from a positive balance of 0.15 percent for the low-cost assumptions to a deficit of 1.85 percent for the high-cost assumptions.

The summarized long-range (75-year) balance as a percentage of GDP for the combined OASDI and HI programs varies among the three alternatives by a relatively large amount, from a positive balance of 0.62 percent under the low-cost assumptions to a deficit of 3.98 percent under the high-cost assumptions. The 25-year summarized balance varies by a smaller amount, from a positive balance of 0.39 percent to a deficit of 2.10 percent. Summarized rates are calculated on a present-value basis. They include the trust fund balances on January 1, 2015 and the cost of reaching a target trust fund level equal to 100 percent of the following year's annual cost at the end of the period. (See section IV.B.4 for further explanation.)

Table VI.G4.—OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, Calendar Years 2015-90

Calendar year	OASDI Income[1]	OASDI Cost	OASDI Balance	HI Income[a]	HI Cost	HI Balance	Combined Income[a]	Combined Cost	Combined Balance	GDP in dollars (billions)
Intermediate:										
2015	4.52	4.98	-0.46	1.47	1.49	-0.02	5.99	6.47	-0.48	$18,163
2016	4.54	4.89	-.35	1.49	1.48	.01	6.03	6.38	-.35	19,216
2017	4.61	4.96	-.35	1.51	1.47	.04	6.12	6.43	-.31	20,311
2018	4.65	5.02	-.37	1.53	1.48	.05	6.18	6.50	-.32	21,415
2019	4.68	5.10	-.41	1.54	1.50	.05	6.23	6.59	-.37	22,537
2020	4.71	5.17	-.46	1.56	1.53	.03	6.27	6.70	-.43	23,687
2021	4.74	5.23	-.50	1.57	1.56	.01	6.31	6.80	-.49	24,861
2022	4.76	5.31	-.55	1.58	1.60	-.02	6.34	6.92	-.57	26,042
2023	4.78	5.41	-.62	1.59	1.64	-.04	6.38	7.04	-.67	27,234
2024	4.80	5.50	-.70	1.60	1.67	-.07	6.41	7.17	-.76	28,472
2025	4.80	5.57	-.77	1.61	1.74	-.13	6.41	7.31	-.90	29,765
2030	4.80	5.87	-1.07	1.64	1.90	-.26	6.44	7.77	-1.33	37,089
2035	4.78	6.02	-1.24	1.67	2.05	-.38	6.45	8.07	-1.62	46,085
2040	4.77	6.03	-1.26	1.69	2.13	-.45	6.46	8.16	-1.71	57,462
2045	4.75	5.97	-1.22	1.71	2.17	-.46	6.46	8.14	-1.68	71,742
2050	4.74	5.93	-1.19	1.73	2.17	-.44	6.47	8.10	-1.63	89,342

2055	4.73	5.96	-1.23	1.76	2.16	-.40	6.49	8.12	-1.63	110,936
2060	4.71	6.03	-1.32	1.78	2.15	-.37	6.50	8.18	-1.68	137,548
2065	4.69	6.09	-1.40	1.81	2.17	-.36	6.50	8.26	-1.76	170,579
2070	4.67	6.15	-1.48	1.82	2.20	-.38	6.49	8.35	-1.86	211,683
2075	4.65	6.18	-1.53	1.84	2.23	-.39	6.49	8.41	-1.92	262,889
2080	4.62	6.15	-1.53	1.85	2.23	-.39	6.47	8.38	-1.92	326,408
2085	4.60	6.16	-1.56	1.86	2.23	-.37	6.46	8.38	-1.92	404,758
2090	4.59	6.20	-1.62	1.87	2.22	-.35	6.46	8.42	-1.97	501,306
Summarized rates: [2]										
25-year:										
2015-39	5.32	5.83	-.51	1.65	1.85	-.20	6.97	7.68	-.71	
50-year:										
2015-64	5.07	5.87	-.80	1.69	1.98	-.29	6.76	7.85	-1.09	
75-year:										
2015-89	4.96	5.92	-.96	1.73	2.03	-.30	6.69	7.95	-1.26	
Low-cost:										
2015	4.50	4.91	-.41	1.47	1.45	.02	5.98	6.36	-.38	18,376
2016	4.59	4.74	-.15	1.49	1.40	.09	6.08	6.14	-.06	19,776
2017	4.62	4.72	-.11	1.51	1.36	.15	6.13	6.08	.05	21,261
2018	4.67	4.73	-.07	1.53	1.34	.19	6.20	6.07	.12	22,749
2019	4.71	4.76	-.05	1.54	1.33	.21	6.26	6.09	.16	24,245
2020	4.75	4.80	-.05	1.55	1.33	.22	6.30	6.13	.17	25,767
2021	4.78	4.83	-.05	1.56	1.33	.23	6.34	6.17	.18	27,333
2022	4.82	4.87	-.06	1.57	1.34	.23	6.39	6.21	.17	28,970
2023	4.85	4.92	-.08	1.58	1.34	.24	6.43	6.26	.16	30,694
2024	4.87	4.97	-.10	1.59	1.34	.25	6.47	6.32	.15	32,504
2025	4.88	5.01	-.13	1.60	1.38	.22	6.48	6.39	.09	34,408
2030	4.88	5.16	-.28	1.64	1.37	.28	6.52	6.52	[3]	45,697
2035	4.88	5.19	-.31	1.68	1.34	.34	6.56	6.53	.03	60,563
2040	4.88	5.10	-.23	1.72	1.27	.45	6.59	6.37	.22	80,726
2045	4.88	4.98	-.10	1.76	1.19	.57	6.63	6.17	.47	108,017
2050	4.89	4.91	-.02	1.79	1.12	.68	6.68	6.02	.66	144,330
2055	4.89	4.91	-.01	1.83	1.06	.77	6.72	5.97	.75	192,279
2060	4.90	4.94	-.04	1.86	1.04	.82	6.76	5.98	.78	255,850
2065	4.90	4.96	-.06	1.89	1.05	.84	6.79	6.01	.78	340,834
2070	4.90	4.97	-.07	1.91	1.07	.84	6.81	6.04	.77	454,976
2075	4.89	4.94	-.05	1.93	1.09	.84	6.82	6.03	.80	608,502
2080	4.89	4.86	.02	1.94	1.10	.85	6.83	5.96	.87	813,923
2085	4.89	4.85	.04	1.96	1.10	.86	6.85	5.95	.90	1,086,422
2090	4.90	4.92	-.02	1.98	1.10	.88	6.88	6.02	.86	1,446,970
Low-cost (Cont.):										
Summarized rates: [b]										
25-year:										

2015-39	5.35	5.22	.14	1.65	1.40	.25	7.01	6.62	.39	
50-year:										
2015-64	5.15	5.08	.07	1.72	1.26	.45	6.86	6.34	.52	
75-year:										
2015-89	5.08	5.02	.06	1.78	1.22	.56	6.86	6.24	.62	
High-cost:										
2015	4.54	5.07	-.53	1.47	1.55	-.08	6.02	6.62	-.61	17,880
2016	4.52	5.11	-.59	1.49	1.58	-.10	6.01	6.69	-.68	18,516
2017	4.60	5.24	-.65	1.51	1.60	-.09	6.10	6.84	-.74	19,246
2018	4.63	5.36	-.73	1.53	1.64	-.11	6.16	7.00	-.84	20,019
2019	4.66	5.49	-.83	1.55	1.70	-.15	6.20	7.18	-.98	20,795
2020	4.68	5.61	-.94	1.56	1.77	-.20	6.24	7.38	-1.14	21,575
2021	4.69	5.72	-1.03	1.58	1.84	-.27	6.27	7.57	-1.29	22,376
2022	4.71	5.84	-1.13	1.59	1.93	-.33	6.31	7.77	-1.46	23,181
2023	4.73	5.97	-1.24	1.61	2.01	-.40	6.34	7.98	-1.64	23,979
2024	4.75	6.12	-1.37	1.62	2.09	-.47	6.37	8.21	-1.85	24,738
2025	4.75	6.23	-1.48	1.63	2.22	-.60	6.37	8.45	-2.08	25,543
2030	4.73	6.70	-1.97	1.65	2.66	-1.01	6.38	9.36	-2.99	29,888
2035	4.70	7.00	-2.30	1.67	3.14	-1.48	6.37	10.15	-3.78	34,863
2040	4.68	7.15	-2.47	1.68	3.61	-1.93	6.36	10.76	-4.40	40,679
2045	4.65	7.20	-2.55	1.69	3.99	-2.30	6.33	11.19	-4.85	47,436
2050	4.62	7.24	-2.62	1.69	4.24	-2.55	6.31	11.48	-5.17	55,079
2055	4.59	7.33	-2.74	1.70	4.39	-2.68	6.29	11.72	-5.43	63,679
2060	4.56	7.46	-2.90	1.71	4.46	-2.75	6.27	11.93	-5.65	73,474
2065	4.52	7.59	-3.07	1.72	4.50	-2.78	6.25	12.09	-5.85	84,697
2070	4.49	7.74	-3.26	1.73	4.54	-2.81	6.22	12.28	-6.06	97,561
2075	4.45	7.86	-3.42	1.74	4.57	-2.83	6.19	12.44	-6.24	112,331
2080	4.41	7.92	-3.51	1.75	4.55	-2.80	6.15	12.47	-6.32	129,209
2085	4.37	7.97	-3.60	1.75	4.51	-2.75	6.12	12.48	-6.36	148,465
2090	4.34	8.02	-3.68	1.76	4.47	-2.71	6.10	12.49	-6.39	170,494
Summarized rates: b										
25-year:										
2015-39	5.31	6.56	-1.25	1.66	2.51	-.85	6.96	9.07	-2.10	
50-year:										
2015-64	5.01	6.84	-1.84	1.67	3.22	-1.54	6.68	10.06	-3.38	
75-year:										
2015-89	4.88	7.05	-2.18	1.69	3.50	-1.81	6.57	10.55	-3.98	

1 Income for individual years excludes interest on the trust funds. Interest is implicit in all summarized values.

2 Summarized rates are calculated on a present-value basis. They include the value of the trust funds on January 1, 2015 and the cost of reaching a target trust fund level equal to 100 percent of annual cost at the end of the period.

3 Between -0.005 and 0 percent of GDP.

Note: Totals do not necessarily equal the sums of rounded components.

To compare trust fund operations expressed as percentages of taxable payroll and those expressed as percentages of GDP, table VI.G5 displays ratios of OASDI taxable payroll to GDP. HI taxable payroll is about 25 percent larger than the OASDI taxable payroll throughout the long-range period; see section 1 of this appendix for a detailed description of the difference. The cost as a percentage of GDP is equal to the cost as a percentage of taxable payroll multiplied by the ratio of taxable payroll to GDP.

Table VI.G5.—Ratio of OASDI Taxable Payroll to GDP, Calendar Years 2015-90

Calendar year	Intermediate	Low-cost	High-cost
2015	0.353	0.353	0.352
2016	.353	.356	.352
2017	.357	.358	.355
2018	.360	.362	.357
2019	.362	.365	.358
2020	.363	.368	.359
2021	.365	.370	.360
2022	.366	.372	.360
2023	.367	.374	.361
2024	.368	.376	.361
2025	.367	.375	.360
2030	.365	.374	.356
2035	.362	.373	.352
2040	.361	.373	.349
2045	.360	.374	.347
2050	.359	.374	.344
2055	.357	.375	.341
2060	.356	.375	.338
2065	.354	.375	.334
2070	.351	.375	.330
2075	.349	.374	.326
2080	.347	.374	.323
2085	.346	.375	.319
2090	.344	.375	.316

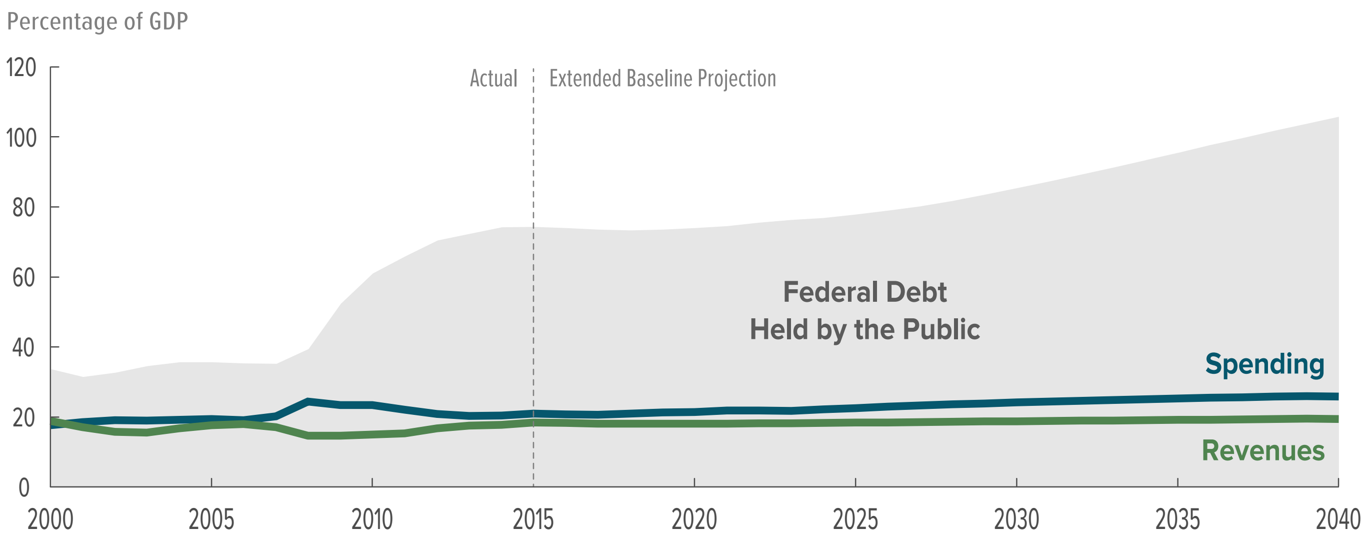
Projections of GDP reflect projected increases in U.S. employment, labor productivity, average hours worked, and the GDP deflator. Projections of taxable payroll reflect the components of growth in GDP along with assumed changes in the ratio of worker compensation to GDP, the ratio of earnings to worker compensation, the ratio of OASDI covered earnings to total earnings, and the ratio of taxable to total covered earnings.

Over the long-range period, the ratio of OASDI taxable payroll to GDP is projected to decline mostly due to a projected decline in the ratio of wages to employee compensation. Over the last five complete economic cycles, the ratio of wages to employee compensation declined at an average annual rate of 0.23 percent. Over the 65-year period ending in 2089, the ratio of wages to employee compensation is projected to decline at an average annual rate of 0.09 and 0.19 percent for the intermediate and high-cost assumptions, respectively, and to increase at an average annual rate of 0.01 percent for the low-cost assumptions.

CONGRESS OF THE UNITED STATES
CONGRESSIONAL BUDGET OFFICE

CBO

The 2015 Long-Term Budget Outlook



If Lawmakers Aimed for Debt in 2040 to Equal . . .

Its 50-Year Average of **38%** of GDP. . .	Its Current Level of **74%** of GDP. . .

How Much Would They Need to Increase Revenues or Reduce Noninterest Spending per Year?

2.6% of GDP, which is equal to a **14%** Increase in **Revenues** or **13%** Cut in **Spending**	**1.1%** of GDP, which is equal to a **6%** Increase in **Revenues** or **5½%** Cut in **Spending**

JUNE 2015

Notes

Unless otherwise indicated, the years referred to in most of this report are federal fiscal years, which run from October 1 to September 30 and are designated by the calendar year in which they end. In Chapters 6 and 7, budgetary values, such as the ratio of debt or deficits to gross domestic product, are presented on a fiscal year basis, whereas economic variables, such as gross national product or interest rates, are presented on a calendar year basis.

Numbers in the text, tables, and figures of this report may not add up to totals because of rounding. Also, some values are expressed as fractions to indicate numbers rounded to amounts greater than a tenth of a percentage point.

As referred to in this report, the Affordable Care Act comprises the Patient Protection and Affordable Care Act and the health care provisions of the Health Care and Education Reconciliation Act of 2010, as affected by subsequent judicial decisions, statutory changes, and administrative actions.

The figure on the cover shows federal revenues, spending, and debt held by the public under CBO's extended baseline.

Additional data—including the data underlying the figures in this report, supplemental budget projections, and the demographic and economic variables underlying those projections—are posted along with the report on CBO's website.

Contents

Summary

The long-term outlook for the federal budget has worsened dramatically over the past several years, in the wake of the 2007–2009 recession and slow recovery. Between 2008 and 2012, financial turmoil and a severe drop in economic activity, combined with various policies implemented in response to those conditions, sharply reduced federal revenues and increased spending. As a result, budget deficits rose: They totaled $5.6 trillion in those five years, and in four of the five years, they were larger relative to the size of the economy than they had been in any year since 1946. Because of the large deficits, federal debt held by the public soared, nearly doubling during the period. It is now equivalent to about 74 percent of the economy's annual output, or gross domestic product (GDP)—a higher percentage than at any point in U.S. history except a seven-year period around World War II.[1]

If current law remained generally unchanged in the future, federal debt held by the public would decline slightly relative to GDP over the next few years, the Congressional Budget Office projects. After that, however, growing budget deficits—caused mainly by the aging of the population and rising health care costs—would push debt back to, and then above, its current high level. The deficit would grow from less than 3 percent of GDP this year to more than 6 percent in 2040. At that point, 25 years from now, federal debt held by the public would exceed 100 percent of GDP.

Moreover, debt would still be on an upward path relative to the size of the economy. Consequently, the policy changes needed to reduce debt to any given amount would become larger and larger over time. The rising debt could not be sustained indefinitely; the government's creditors would eventually begin to doubt its ability to cut spending or raise revenues by enough to pay its debt obligations, forcing the government to pay much higher interest rates to borrow money.

What Is the Outlook for the Budget in the Next 10 Years?

The economy's gradual recovery from the recession, the waning budgetary effects of policies enacted in response to the weak economy, and other changes to tax and spending laws will cause the deficit to shrink in 2015 to its smallest percentage of GDP since 2007, CBO projects—2.7 percent, a much smaller percentage than the recent peak of nearly 10 percent in 2009.[2] Throughout the next decade, however, an aging population, rising health care costs per person, and an increasing number of recipients of exchange subsidies and Medicaid benefits attributable to the Affordable Care Act would push up spending for some of the largest federal programs if current laws governing those programs remained unchanged. Moreover, CBO expects interest rates to rebound in coming years from their current unusually low levels, raising the government's interest payments on debt.

1. When analyzing changes in spending, revenues, deficits, and debt, CBO usually measures those amounts relative to economic output. That approach automatically incorporates inflation and growth in population, output, and income, providing context for understanding the size of the government's activities at different points in time and their effects on the sustainability of the budget.

2. The projections in this report are consistent with CBO's March 2015 budget projections after adjustments are made to incorporate the effects of recently enacted legislation. The most important such adjustment was to incorporate the estimated effect of Public Law 114-10, the Medicare Access and CHIP [Children's Health Insurance Program] Reauthorization Act of 2015, which became law on April 16, 2015. For information on the March baseline budget projections, see Congressional Budget Office, *Updated Budget Projections: 2015 to 2025* (March 2015), www.cbo.gov/publication/49973.

Budget deficits would not substantially increase at first, but eventually they would begin to rise. They would approach 4 percent of GDP toward the end of the 10-year period spanned by CBO's baseline budget projections, the agency anticipates. Deficits over the entire period would total about $7.4 trillion.

With deficits projected to remain close to their current percentage of GDP for the next few years, federal debt held by the public would remain at a very high level, between 73 percent and 74 percent of GDP, from 2016 through 2021. Thereafter, the larger deficits would boost debt—to 78 percent of GDP by the end of 2025.

What Is the Outlook for the Budget Through 2040?

To analyze the state of the budget in the long term, CBO has extrapolated its 10-year baseline projections through 2040, yielding a set of *extended* baseline projections that span a total of 25 years. (Both sets of projections generally incorporate the assumption that current law will not change.) Mainly because of the aging of the population and rising health care costs, the extended baseline projections show revenues that fall well short of spending over the long term, producing a substantial imbalance in the federal budget. As a result, budget deficits are projected to rise steadily and, by 2040, to raise federal debt held by the public to a percentage of GDP seen at only one previous time in U.S. history—the final year of World War II and the following year.

The harmful effects that such large debt would have on the economy would worsen the budget outlook. The projected increase in debt relative to the size of the economy, combined with a gradual increase in effective marginal tax rates (that is, the rates that would apply to an additional dollar of income), would make economic output lower and interest rates higher than CBO projected when producing the extended baseline. Those macroeconomic effects would, in turn, feed back into the budget, leading to lower federal revenues and higher interest payments on the debt. (The harm that growing debt would cause to the economy was not factored into CBO's detailed long-term budgetary projections, and it is generally not reflected in the discussion of the extended baseline elsewhere in this summary, but it is addressed in further analysis presented in Chapter 6.)

In the extended baseline projections, before those feedback effects are considered, federal spending rises from 20.5 percent of GDP this year to 25.3 percent of GDP by 2040 (see Summary Table 1). (Its average over the past 50 years has been 20.1 percent.) The projected increase reflects the following paths for various types of spending:

- Federal spending for Social Security and the government's major health care programs—Medicare, Medicaid, the Children's Health Insurance Program, and subsidies for health insurance purchased through the exchanges created by the Affordable Care Act—would rise sharply, to 14.2 percent of GDP by 2040, if current law remained generally unchanged. That percentage would be more than twice the 6.5 percent average seen over the past 50 years. The boost in spending is projected to occur because of the aging of the population; growth in per capita spending on health care; and, to a lesser extent, an increased number of recipients of exchange subsidies and Medicaid benefits attributable to the Affordable Care Act.

- The government's net outlays for interest would grow to 4.3 percent of GDP by 2040, CBO projects. That percentage would be higher than the 2.0 percent average of the past 50 years, because federal debt would be much larger.

- In contrast, other noninterest spending—that is, spending on everything other than Social Security, the major health care programs, and net interest—would decline to 6.9 percent of GDP by 2040, which would be well below the 11.6 percent average of the past 50 years.

Federal revenues would also increase relative to GDP under current law, but much more slowly than federal spending would. Revenues would equal 19.4 percent of GDP by 2040, CBO projects, which would be higher than the 50-year average of 17.4 percent. That increase would occur mainly because people's income grew more rapidly than inflation, pushing more income into higher tax brackets over time.[3]

3. One consequence is that individual income and payroll taxes as a share of income would grow for many households. For example, a married couple with two children earning the median income in 2014 and filing a joint tax return would have paid about 16 percent of their income in individual income and payroll taxes. Under current law, a similar couple earning the median income 25 years from now would pay about 19 percent of their income in individual income and payroll taxes.

Summary Table 1.

Key Projections Under CBO's Extended Baseline

Percentage of Gross Domestic Product

	2015	2025	2040
		Without Macroeconomic Feedback[a]	
Revenues			
Individual income taxes	8.4	9.5	10.4
Payroll taxes	5.9	5.7	5.7
Corporate income taxes	1.8	1.8	1.8
Other sources of revenues	1.7	1.2	1.5
Total Revenues	**17.7**	**18.3**	**19.4**
Spending			
Mandatory			
Social Security	4.9	5.7	6.2
Major health care programs[b]	5.2	6.1	8.0
Other mandatory programs	2.6	2.3	1.8
Subtotal	12.7	14.1	16.0
Discretionary	6.5	5.1	5.1
Net interest	1.3	3.0	4.3
Total Spending	**20.5**	**22.2**	**25.3**
Deficit	-2.7	-3.8	-5.9
Debt Held by the Public at the End of the Year	74	78	103
		With Macroeconomic Feedback	
Deficit	-2.7	-3.8	-6.6
Debt Held by the Public at the End of the Year	74	78	107
Memorandum:			
Social Security[a]			
Revenues[c]	4.4	4.3	4.3
Spending	4.9	5.7	6.2
Net increase (-) in deficit	-0.5	-1.4	-1.9
Medicare[a]			
Revenues[c]	1.5	1.6	1.7
Spending	3.5	4.4	6.3
Offsetting receipts	-0.5	-0.8	-1.2
Net increase (-) in deficit	-1.5	-2.0	-3.4
Tax Expenditures	8.1	n.a.	n.a.
Gross Domestic Product (Billions of dollars)[a]	18,016	27,456	50,800

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

n.a. = not available.

a. These projections do not reflect the macroeconomic feedback of the policies underlying the extended baseline after 2025. (For an analysis of those effects and their impact on debt, see Chapter 6.)

b. Net of offsetting receipts for Medicare.

c. Revenues include payroll taxes other than those paid by the federal government for federal employees, which are intragovernmental transactions. Revenues also include income taxes paid on Social Security benefits, which are credited to the trust funds.

By 2040, in CBO's projections that do not account for macroeconomic feedback effects, the deficit equals 5.9 percent of GDP, a higher percentage than in any year between 1947 and 2008. The resulting debt reaches 103 percent of GDP in 2040, more than in any year except 1945 and 1946.

Under the extended baseline with feedback effects included, CBO's estimate of the deficit in 2040 is higher—6.6 percent of GDP—and so is its estimate of federal debt held by the public: 107 percent of GDP.

What Consequences Would a Large and Growing Federal Debt Have?

How long the nation could sustain such growth in federal debt is impossible to predict with any confidence. At some point, investors would begin to doubt the government's willingness or ability to meet its debt obligations, requiring it to pay much higher interest costs in order to continue borrowing money. Such a fiscal crisis would present policymakers with extremely difficult choices and would probably have a substantial negative impact on the country. Unfortunately, there is no way to predict confidently whether or when such a fiscal crisis might occur in the United States. In particular, as the debt-to-GDP ratio rises, there is no identifiable point indicating that a crisis is likely or imminent. But all else being equal, the larger a government's debt, the greater the risk of a fiscal crisis.[4]

Even before a crisis occurred, the high and rising debt that CBO projects in the extended baseline would have macroeconomic effects with significant negative consequences for both the economy and the federal budget:

- The large amount of federal borrowing would draw money away from private investment in productive capital over the long term, because the portion of people's savings used to buy government securities would not be available to finance private investment. The result would be a smaller stock of capital, and therefore lower output and income, than would otherwise have been the case, all else being equal. (Despite those reductions, output and income per person, adjusted for inflation, would be higher in the future than they are now, thanks to the continued growth of productivity.)

- Federal spending on interest payments would rise, thus requiring the government to raise taxes, reduce spending for benefits and services, or both to achieve any targets that it might choose for budget deficits and debt.

- The large amount of debt would restrict policymakers' ability to use tax and spending policies to respond to unexpected challenges, such as economic downturns or financial crises. As a result, those challenges would tend to have larger negative effects on the economy and on people's well-being than they would otherwise. The large amount of debt could also compromise national security by constraining defense spending in times of international crisis or by limiting the country's ability to prepare for such a crisis.

What Effects Would Alternative Fiscal Policies Have?

Again, most of the projections in this report are based on the assumption that federal tax and spending policies will generally not differ from what current law specifies. (CBO makes that assumption not because it expects current law to remain the same, but because the budgetary and economic implications of current law are a useful benchmark for policymakers when they consider changing laws.) However, if tax and spending policies differed significantly from those specified in current law, budgetary and economic outcomes could differ significantly as well. To illustrate some possible differences, CBO analyzed the effects of three additional sets of fiscal policies: an extended alternative fiscal scenario, which would result in more debt than in the extended baseline; and two illustrative scenarios, which would result in less.

Under the extended alternative fiscal scenario, certain policies that are now in place but that are scheduled to change under current law are assumed to continue; some provisions of law that might be difficult to sustain for a long period are assumed to be modified; and federal revenues and certain kinds of federal spending are assumed to be maintained at or near their historical shares of GDP. If those changes to current law occurred, deficits (excluding interest payments) would be about $2 trillion higher over the next decade than they are in CBO's baseline; in subsequent years, such deficits would exceed those projected in the extended baseline by rapidly growing amounts. The harmful effects on the economy from the resulting increase in federal debt would be partly offset by the lower marginal tax rates that would be in place under

4. For further discussion, see Congressional Budget Office, *Federal Debt and the Risk of a Fiscal Crisis* (July 2010), www.cbo.gov/publication/21625.

the scenario. Nevertheless, in the long term, economic output would be lower and interest rates would be higher under the scenario than they would be if current law remained in place. After including the effects of those macroeconomic changes, CBO projects that federal debt held by the public would rise sharply—to about 175 percent of GDP in 2040.

Under the first of the two illustrative scenarios, budget deficits would be smaller than those projected under current law. Deficit reduction would be phased in so that deficits (excluding interest payments) would be a total of $2 trillion smaller through 2025 than they are in CBO's baseline; thereafter, deficits would be reduced each year by the same percentage of GDP by which they had been reduced in 2025. If that scenario occurred, output would be higher and interest rates would be lower in the long term than they would be if current law remained unchanged. Factoring in the effects of those macroeconomic changes on the budget, CBO projects that federal debt held by the public would equal about 72 percent of GDP in 2040, close to its percentage in 2013.

Under the other illustrative scenario, one with twice as much deficit reduction as in the previous scenario—a total decrease of $4 trillion in deficits (excluding interest payments) through 2025—CBO projects that federal debt held by the public would fall to 39 percent of GDP in 2040. That percentage would be close to the average ratio of debt to GDP over the past 50 years (38 percent). As in the preceding scenario, output would be higher and interest rates would be lower in the long term than they would be if current law did not change.

The fiscal policies in the three scenarios would also affect the economy in the short term, reflecting the short-term impact of tax and spending policies on the overall demand for goods and services. The first scenario, by making spending higher and taxes lower than they would be under current law, would increase demand and thereby raise output and employment over the next few years. By contrast, the deficit reduction that would take place under the other scenarios would decrease demand and thus reduce output and employment over the next few years.

How Uncertain Are the Long-Term Budget Projections?

Even if future tax and spending policies did not vary from what current law specifies, budgetary outcomes would undoubtedly differ from CBO's projections because of unexpected changes in the economy, demographics, and other factors.

To illustrate the uncertainty of its projections, CBO examined how varying its estimates of four factors—future mortality rates, productivity growth, interest rates on federal debt, and federal spending on Medicare and Medicaid—would affect the projections in a version of the extended baseline that included the macroeconomic effects of fiscal policies on the budget. In that version of the extended baseline, CBO's central estimate is that federal debt will equal 107 percent of GDP in 2040. The degree of variation in the four factors was based on their past variation as well as on possible future developments. For instance, during recent 25-year periods, beginning in the 1950–1974 period and ending in the 1990–2014 period, the average growth rate of total factor productivity—the average real output per unit of combined capital and labor—varied by about 1 percentage point. CBO therefore projected economic and budgetary outcomes if total factor productivity grew by 0.8 percent per year or by 1.8 percent per year over the next 25 years—that is, 0.5 percentage points more slowly or more quickly than the 1.3 percent projected for the extended baseline. The estimates show the following:

- In cases in which CBO varied only one of the four factors, federal debt held by the public after 25 years ranged from 18 percent of GDP below the agency's central estimate to 23 percent above it.

- In a case in which all four factors varied simultaneously in a way that raised projected deficits, but varied only 60 percent as much as in the individual cases just mentioned, federal debt after 25 years was projected to be about 37 percent of GDP higher than the agency's central estimate. Conversely, in a case in which all four factors varied in a way that lowered deficits but, again, by only 60 percent as much as in the individual cases, debt after 25 years was projected to be lower than CBO's central estimate by 31 percent of GDP.

Those calculations do not cover the full range of possible outcomes, nor do they address other sources of uncertainty in the budget projections, such as the risk of an economic depression or major war or the possibility of unexpected changes in birthrates, immigration, or labor force participation. Nonetheless, they show that the main implication of this report applies under a wide range of possible values for some key factors that influence federal spending and revenues. That is, in 25 years, if current law remained generally unchanged, federal debt—which is already high by historical standards—would probably be at least as high as it is today and would most likely be much higher.

What Choices Do Policymakers Have?

The unsustainable nature of the federal tax and spending policies specified in current law presents lawmakers and the public with difficult choices. Unless substantial changes were made to the major health care programs and Social Security, spending for those programs would equal a much larger percentage of GDP in the future than in the past. Federal spending as a whole would rise rapidly—even though, under current law, spending for all other federal benefits and services would make up a smaller percentage of GDP by 2025 than at any point in more than 70 years. Federal revenues would also represent a larger percentage of GDP in the future than they have, on average, in the past few decades. Even so, spending would soon start to exceed revenues by increasing amounts relative to GDP, generating rising budget deficits. As a result, federal debt held by the public would grow faster than the economy, starting a few years from now. Because debt is already unusually high relative to GDP, further sustained increases could be especially harmful to economic growth.

To put the federal budget on a sustainable path for the long term, lawmakers would have to make major changes to tax policies, spending policies, or both—by reducing spending for large benefit programs below the projected amounts, letting revenues rise more than they would under current law, or adopting some combination of those approaches. The size of such changes would depend on the amount of federal debt that lawmakers considered appropriate.

For instance, if lawmakers set a goal for 2040 of reducing debt held by the public to the average percentage of GDP seen over the past 50 years (38 percent), one approach would be to increase revenues and cut noninterest spending, relative to current law, by a total of 2.6 percent of GDP in each year beginning in 2016. That would come to about $480 billion, or $1,450 per person, in 2016 (see Summary Figure 1).[5] Many combinations of policies could be adopted to meet that goal, including the following:

- At one end of the spectrum, lawmakers could choose to reduce deficits solely by increasing revenues. Such a policy would require boosting revenues by 14 percent in each year over the 2016–2040 period relative to the amounts that CBO projects in the extended baseline. For households in the middle fifth of the income distribution in 2016, a 14 percent increase in all types of revenues would raise federal tax payments for that year by about $1,700, on average.

- At the other end of the spectrum, lawmakers could choose to reduce deficits solely by cutting noninterest spending, in which case they would have to make such spending 13 percent lower than projected in the extended baseline in each of the next 25 years. For example, a 13 percent cut would lower initial Social Security benefits by an average of about $2,400 for people in the middle fifth of the lifetime earnings distribution who were born in the 1950s and who claimed benefits at age 65.

Another goal might be to reduce debt in 2040 to its current percentage of GDP—74 percent. Meeting that goal would require increases in revenues and cuts in noninterest spending, relative to current law, totaling 1.1 percent of GDP in each year beginning in 2016.[6] Of course, other goals and other patterns for the timing of savings are possible as well.

In deciding how quickly to carry out policies to put federal debt on a sustainable path—regardless of the chosen goal for debt—lawmakers would face difficult trade-offs:

5. The estimated size of those policy changes does not account for the macroeconomic effects either of the particular policies that might be changed or of the reduction in debt.

6. The estimated size of those policy changes does not account for the macroeconomic effects of the particular policies that might be changed.

Summary Figure 1.

The Size of Policy Changes Needed Over 25 Years to Make Federal Debt Meet Two Possible Goals in 2040

If Lawmakers Aimed for . . .

Debt in 2040 to Equal Its 50-Year Average of **38%** of GDP . . .	**Debt** in 2040 to Equal Its Current Level of **74%** of GDP . . .

How Much Would They Need to Increase Revenues or Reduce Noninterest Spending per Year?

2.6% of GDP, which is equal to a **14%** Increase in **Revenues** or **13%** Cut in **Spending**	**1.1%** of GDP, which is equal to a **6%** Increase in **Revenues** or **5½%** Cut in **Spending**

What Would That Increase in Revenues or Reduction in Noninterest Spending Amount to in 2016?

$480 billion, which is equal to **$1,450** per person	**$210 billion**, which is equal to **$650** per person

What If the Changes Were Increases (of Equal Percentage) in All Types of Revenues?

+$1,700

One effect in 2016 is that, on average, **taxes on households** would be higher than under current law.

+$750

Values are for households in the middle fifth of the income distribution. Those taxes are projected to be $12,300 under current law.

What If the Changes Were Cuts (of Equal Percentage) in All Types of Noninterest Spending?

-$2,400

One effect is that **initial Social Security benefits** would be lower than under current law.

-$1,050

Values are averages for people in the middle fifth of the lifetime earnings distribution who were born in the 1950s and who would claim benefits at age 65. Those benefits are projected to be $18,650 (in 2016 dollars) under current law.

Source: Congressional Budget Office.

Notes: The values shown in this figure are relative to CBO's extended baseline. The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period. The sizes of the policy changes do not account for the macroeconomic feedback of the policies that might be used to achieve the goals or, in the case of the goal to reduce debt to 38 percent of GDP, of the reduction in debt.

GDP = gross domestic product.

- The sooner significant deficit reduction was implemented, the smaller the government's accumulated debt would be; the smaller the policy changes would need to be to achieve the chosen goal; and the less uncertainty there would be about what policies might be adopted. However, precipitous spending cuts or tax increases would give people little time to plan and adjust to those policy changes, and the changes would weaken the economic expansion during the next two years or so—a period when the Federal Reserve would have little ability to lower short-term interest rates to boost the economy.

- Spending cuts or tax increases that were implemented several years from now would have a smaller negative effect on output and employment in the short term. However, waiting for some time before reducing spending or increasing taxes would result in a greater accumulation of debt, which would represent a greater drag on output and income in the long term and increase the size of the policy changes needed to reach the chosen target for debt.

CBO has estimated how much a delay in deficit reduction would increase the size of the policy changes needed to achieve a chosen goal for debt. If the goal was to reduce debt to its 50-year historical average by 2040, but lawmakers waited to implement new policies until 2021, the combination of increases in revenues and reductions in noninterest spending over the 2021–2040 period would need to equal 3.2 percent of GDP—0.6 percentage points more than if policy changes took effect in 2016. If lawmakers chose the same goal but postponed taking action until 2026, the necessary policy changes over the 2026–2040 period would amount to 4.2 percent of GDP.

Even if policy changes that shrank deficits in the long term were not implemented for several years, making decisions about them sooner rather than later could hold down longer-term interest rates, reduce uncertainty, and enhance businesses' and consumers' confidence. Such decisions could thereby make output and employment higher in the next few years than they would have been otherwise.

CHAPTER

1

The Long-Term Outlook for the Federal Budget

The Congressional Budget Office projects that the deficit will remain roughly stable as a share of the nation's output—its gross domestic product (GDP)—for the next several years if current laws remain generally unchanged. Federal debt held by the public also will be roughly stable relative to the size of the economy for several years, according to CBO's projections. However, the long-term budget outlook is projected to worsen.

The government's spending for major health care programs and for Social Security is a critical factor in that outlook. Such spending is expected to rise significantly from 2015 through 2040 because of a combination of three factors: the aging of the population; growth in per capita spending on health care; and, to a lesser extent, an increased number of recipients of exchange subsidies and Medicaid benefits attributable to the Affordable Care Act (ACA). That boost in spending is expected to exceed the decline in other noninterest spending relative to GDP over the same 25-year period. In addition, revenues are projected to increase, but more slowly than total noninterest spending. Higher interest payments and larger budget deficits would occur as a result, causing federal debt, which is already quite large relative to the size of the economy, to swell even more.

In this report, CBO presents its projections of federal outlays, revenues, deficits, and debt for the next few decades and discusses the possible consequences of the projected budgetary outcomes. The projections are consistent with CBO's current 10-year economic projections, which were released in January 2015, and the agency's March 2015 budget projections, with adjustments to incorporate the effects of recently enacted legislation.[1] CBO's long-term projections, which focus on the 25-year period ending in 2040, extend the baseline concept into later years; hence, they constitute what is called the *extended baseline*.

CBO's 10-year and extended baselines are meant to serve as benchmarks for assessing the budgetary effects of proposed changes in federal revenues or spending. They are not meant to be predictions of future budgetary outcomes; rather, they represent CBO's best assessment of future revenues, spending, and deficits if current law generally remained unchanged and the economy was generally stable in the long term. In that way, the baselines incorporate the assumption that some policy changes that lawmakers have routinely made in the past—such as extending certain expiring tax provisions—will not be made again.

The Budget Outlook for the Next 10 Years

The budget deficit is on track to fall in 2015 to its smallest percentage of economic output since 2007: CBO estimates that the deficit will be less than 3 percent of GDP, which is less than one-third of its peak of nearly 10 percent in 2009. That decline reflects the economy's gradual recovery from the 2007–2009 recession, the waning budgetary effects of policies enacted in response to the weak economy, and other changes to tax and spending policies. Debt held by the public will remain at about 74 percent

1. The most important adjustment to the March 2015 baseline was to incorporate the estimated effect of Public Law 114-10, the Medicare Access and CHIP [Children's Health Insurance Program] Reauthorization Act of 2015, which became law on April 16, 2015. See Congressional Budget Office, cost estimate for H.R. 2, the Medicare Access and CHIP Reauthorization Act of 2015 (March 25, 2015), www.cbo.gov/publication/50053. For information on the March baseline budget projections, see Congressional Budget Office, *Updated Budget Projections: 2015 to 2025* (March 2015), www.cbo.gov/publication/49973. For information on the January 2015 economic projections, see Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), www.cbo.gov/publication/49892.

of GDP at the end of 2015—equal to its value in 2014, when it reached its highest level since 1950.

In those projections, a combination of the anticipated further strengthening of the economy and constraints on federal spending built into law keeps deficits close to their current percentage of GDP for the next several years. With deficits staying below 3 percent of GDP from 2015 through 2019, and then rising slowly thereafter, federal debt held by the public is projected to stay between 73 percent and 74 percent of GDP from 2015 through 2020.

Later in the 10-year baseline projection period, under current law, deficits would be notably larger, CBO anticipates. Interest rates are expected to rebound from their present unusually low levels, sharply increasing interest payments on the government's debt. Moreover, increased spending on the major health care programs and on Social Security is projected to cause mandatory spending to rise as a percentage of GDP.[2] In addition, revenues would grow relative to GDP for the next 10 years as an increase in individual income taxes was offset primarily by a decline in remittances from the Federal Reserve (all relative to the size of the economy). By 2025, under current law, the budget deficit would grow to nearly 4 percent of GDP; federal debt would equal 78 percent of GDP and would be on the rise relative to the size of the economy.

The Long-Term Budgetary Imbalance

The detailed long-term budget estimates that CBO presents in this and the following four chapters depend on projections of a host of demographic and economic conditions that the agency bases primarily on historical patterns. The estimates in these five chapters do not incorporate the long-term economic effects of changes in fiscal policies in the extended baseline; those effects are incorporated, however, in the estimates presented in Chapters 6 and 7. The demographic and economic projections that underlie the detailed long-term budget estimates are summarized later in this chapter and discussed in detail in Appendix A. (Appendix B offers a discussion of changes in CBO's projections since last year.)

CBO's extended baseline projections show a substantial imbalance in the federal budget over the long term, with revenues falling well short of spending. Two measures offer complementary perspectives on the size of that imbalance: Projections of federal debt illustrate how the shortfall in revenues relative to spending would accumulate over time under current law; and estimates of how much spending or revenues would need to be changed to achieve a chosen goal for federal debt illustrate the magnitude of the modifications in law that policymakers might consider.

In addition to its extended baseline, CBO has developed an *extended alternative fiscal scenario*, which incorporates the assumptions that certain policies that have been in place for a number of years will be continued, that some provisions of law that might be difficult to sustain for a long period will be modified, and that federal revenues and certain categories of federal spending will be maintained at or near their historical shares of GDP (see Chapter 6). Under that scenario, federal debt would grow even faster than it would under the extended baseline, so larger policy changes would be needed to reach any chosen fiscal target.

The Accumulation of Federal Debt

Debt held by the public represents the amount that the federal government has borrowed in financial markets, by issuing Treasury securities, to pay for its operations and activities.[3] If a given combination of federal spending and revenues is to be sustainable over time, debt held by the public eventually must grow no faster than the economy

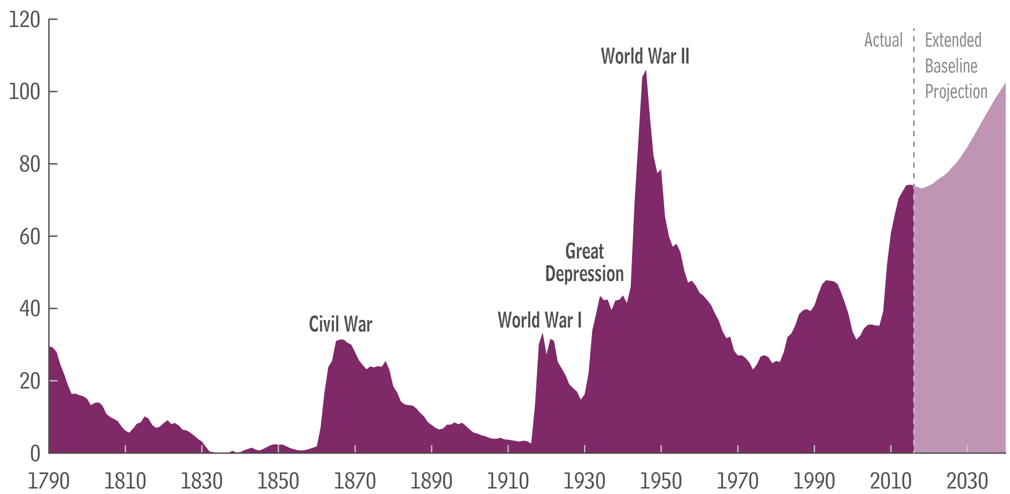
2. Lawmakers generally determine spending for mandatory programs by setting eligibility rules, benefit formulas, and other parameters rather than by appropriating specific amounts each year. In that way, mandatory spending differs from discretionary spending, which is controlled by annual appropriation acts.

3. When the federal government borrows in financial markets, it competes with other participants for financial resources and, in the long term, crowds out private investment, reducing economic output and income. In contrast, federal debt held by trust funds and other government accounts represents internal transactions of the government and has no direct effect on financial markets. (That debt and debt held by the public together make up gross federal debt.) For more discussion, see Congressional Budget Office, *Federal Debt and Interest Costs* (December 2010), www.cbo.gov/publication/21960. Several factors not directly included in the budget totals also affect the government's need to borrow from the public. They include increases or decreases in the government's cash balance as well as the cash flows reflected in the financing accounts used for federal credit programs.

Figure 1-1.

Federal Debt Held by the Public

Percentage of Gross Domestic Product



The historically high and rising amounts of federal debt that CBO projects would have significant negative consequences, including reducing the total amounts of national saving and income in the long term; increasing the government's interest payments, thereby putting more pressure on the rest of the budget; limiting lawmakers' flexibility to respond to unforeseen events; and increasing the likelihood of a fiscal crisis.

Source: Congressional Budget Office. For details about the sources of data used for past debt held by the public, see Congressional Budget Office, *Historical Data on Federal Debt Held by the Public* (July 2010), www.cbo.gov/publication/21728.

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period. These projections do not reflect the macroeconomic feedback of the policies underlying the extended baseline. (For an analysis of those effects and their impact on debt, see Chapter 6.)

does. If debt continued to rise relative to GDP, at some point investors would begin to doubt the government's willingness or ability to repay its obligations. Such doubts would make it more expensive for the government to borrow money, thus necessitating cuts in spending, increases in taxes, or some combination of those two approaches. For that reason, the amount of federal debt held by the public relative to the nation's annual economic output is an important barometer of the government's financial position.

Measuring debt as a percentage of GDP is particularly useful when making comparisons between amounts of debt in different years. That measure accounts for changes in price levels, population, output, and income—all of which affect the scope of potential budgetary adjustments. Examining whether debt as a percentage of GDP is increasing over time from its current high level is therefore a simple and meaningful way to assess the sustainability of the budget.

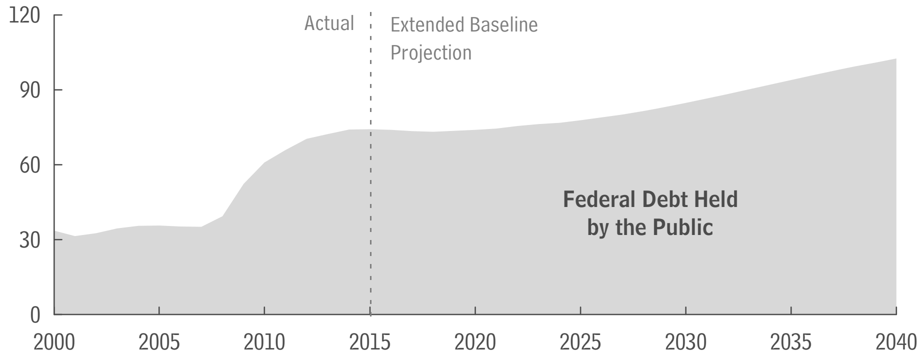
At the end of 2008, federal debt held by the public stood at 39 percent of GDP, which was close to its average of the preceding several decades. Since then, large deficits have caused debt held by the public to grow sharply—to 74 percent of GDP in 2014; debt is projected to stay at that level in 2015. Debt has exceeded 70 percent of GDP during only one other period in U.S. history: from 1944 through 1950; it peaked at 106 percent of GDP in 1946 because of the surge in federal spending that occurred during World War II (see Figure 1-1).

CBO projects that, as a share of GDP, debt held by the public will exceed its current level in 2021 and then keep rising if existing laws remain unchanged. By 2040, under the extended baseline, federal debt held by the public would reach 103 percent of GDP, even without accounting for the harmful economic effects of the growing debt (see Figure 1-2)—nearly the same percentage as that recorded in 1945 (104 percent) and in 1946 (106 percent) and more than two and a half times the average percentage during the past several decades. Incorporating the negative economic effects of higher debt pushes the projected debt up to 107 percent of GDP in 2040 (see Chapter 6). Moreover, the debt would be on an upward trajectory, which ultimately would be unsustainable.

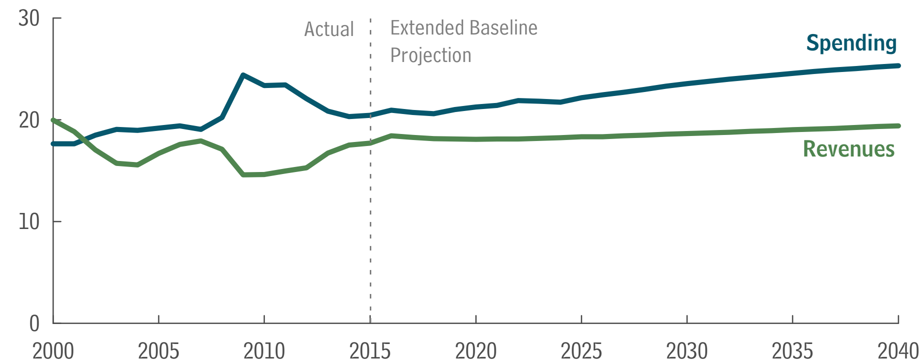
Figure 1-2.

Federal Debt, Spending, and Revenues

Percentage of Gross Domestic Product



Deficits and **debt held by the public** will remain roughly stable in the near term, reflecting the anticipated further strengthening of the economy and constraints on federal spending built into law. But the long-term outlook for the budget is projected to worsen . . .



. . . as growth in **total spending** would outpace growth in **total revenues**, resulting in larger budget deficits and debt if current laws remained generally unchanged.

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period. These projections do not reflect the macroeconomic feedback of the policies underlying the extended baseline. (For an analysis of those effects and their impact on debt, see Chapter 6.)

GDP = gross domestic product.

Continued

Projections so far into the future are highly uncertain, of course. Nevertheless, under a wide range of possible expectations about key factors affecting budgetary outcomes, CBO anticipates that if current laws generally stayed the same, federal debt in 2040 would be very high by the nation's historical standards (see Chapter 7).

The Magnitude and Timing of Policy Changes Needed to Meet Various Goals for Federal Debt

An alternative perspective on the long-term fiscal imbalance comes from assessing the changes in revenues or noninterest spending that would be needed to achieve a chosen goal for federal debt. One possible goal would be to try to ensure that federal debt remained the same percentage of GDP in some future year that it is today. Another would be to attempt to make federal debt the same percentage of GDP in some future year that it has been, on average, during the past several decades. Other goals are possible as well.

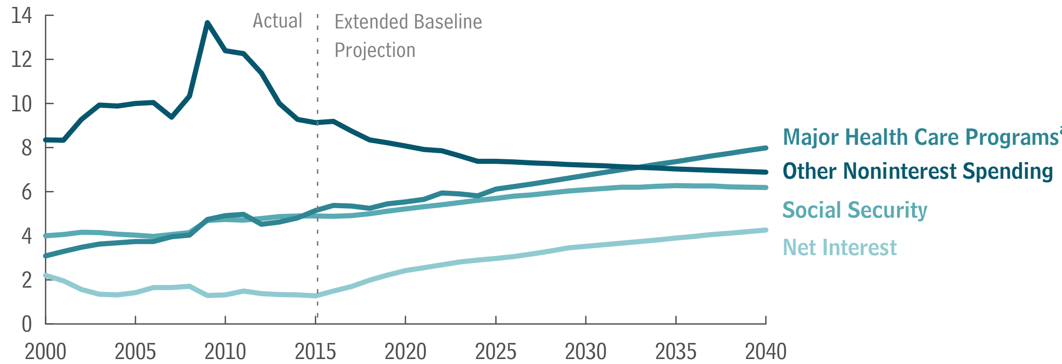
The changes in revenues or noninterest spending that are estimated to be necessary to achieve one of those goals are conceptually similar to the estimated actuarial imbalance—that is, a negative actuarial balance—that is commonly reported for the Social Security trust funds (see Table 3-1 on page 54). An estimated actuarial imbalance for a trust fund over a given period represents the changes in revenues or spending that would be needed to achieve the target balance for the trust funds if those changes were enacted immediately and maintained throughout the period. A similar calculation for the

Figure 1-2. **Continued**

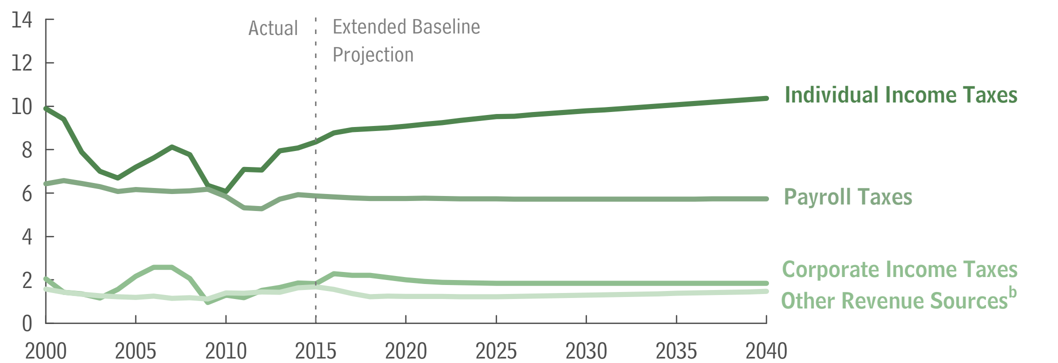
Federal Debt, Spending, and Revenues

Percentage of Gross Domestic Product

Growth in certain **components of spending**—the major health care programs and Social Security—is expected to exceed the decline in other noninterest spending relative to GDP. Net interest costs will also grow, as interest rates rebound . . .



. . . and as revenues grow only slightly more rapidly than GDP. A boost in one of the **sources of revenues**—individual income taxes—accounts for the rise in total revenues; receipts from all other sources, taken together, are projected to decline.



a. Consists of spending on Medicare (net of offsetting receipts), Medicaid, the Children's Health Insurance Program, and subsidies offered through health insurance exchanges.

b. Consists of excise taxes, remittances to the Treasury from the Federal Reserve System, customs duties, estate and gift taxes, and miscellaneous fees and fines.

federal government as a whole is one way to summarize the projected fiscal imbalance over a specified period.

The magnitude of the policy changes that would be needed to achieve a chosen goal for federal debt would depend, in part, on how quickly that goal was expected to be reached. Determining the timing of policy changes involves various trade-offs, including the economic effects of those changes and the burdens borne by different generations.

The Magnitude of Policy Changes Needed to Meet Various Goals. The scale of the changes in noninterest spending or revenues that would be needed to ensure that federal debt equaled its current percentage of GDP at a specific date in the future is often referred to as the fiscal gap.[4] In CBO's extended baseline, the fiscal gap for the 2016–2040 period amounts to 1.1 percent of GDP (without accounting for the economic effects of the policy changes that might be used to close the gap). That is, relative to the extended baseline, a combination of cuts in noninterest spending and increases in revenues that equaled 1.1 percent of GDP in each year beginning in 2016—amounting to about $210 billion in that year or

4. The fiscal gap equals the present value of noninterest outlays and other means of financing minus the present value of revenues over the projected period with adjustments to make the ratio of federal debt to GDP at the end of the period equal to the current ratio. Specifically, current debt is added to the present value of outlays and other means of financing, and the present value of the target end-of-period debt (which equals GDP in the last year of the period multiplied by the ratio of debt to GDP at the end of 2015) is added to the present value of revenues. The present value of a flow of revenues or outlays over time is a single number that expresses that flow in terms of an equivalent sum received or paid at a specific time. The present value depends on a rate of interest (known as the discount rate) that is used to translate past and future cash flows into current dollars. Other means of financing include changes in the government's cash balances and the cash flows of federal credit programs (mostly programs that provide loans and loan guarantees).

$650 per person—would result in debt in 2040 that would equal 74 percent of GDP, or the same percentage of GDP in 25 years that it equals now. If those changes came entirely from revenues or entirely from spending, they would amount, roughly, to a 6 percent increase in revenues or a 5½ percent cut in noninterest spending relative to the amounts projected for the 2016–2040 period.

Increases in revenues or reductions in noninterest spending would need to be larger to reduce debt to the percentages of GDP that are more typical of those in recent decades. For debt as a share of GDP to return to its average percentage over the past 50 years—38 percent—by 2040, the government would need to pursue a combination of increases in revenues and cuts in noninterest spending (relative to current-law projections) that totaled 2.6 percent of GDP each year. (Those increases and cuts would not account for the economic effects of the reduction in debt and the policy changes that might be used to achieve the goal; in 2016, 2.6 percent of GDP would be about $480 billion or $1,450 per person.)[5] Many combinations of policies could be adopted to meet that goal, including the following:

- If those changes came from increases of equal percentage in all types of revenues, they would represent an increase of about 14 percent, under the extended baseline, for each year in the 2016–2040 period. For households in the middle fifth of the income distribution in 2016, for example, such an increase would raise annual federal tax payments by about $1,700, on average.

- If the changes came from cuts of equal percentage in all types of noninterest spending, they would represent a cut of about 13 percent for each of the next 25 years. For example, people in the middle fifth of the lifetime earnings distribution who were born in the 1950s and who claimed benefits at age 65 would have their initial annual Social Security benefits lowered by about $2,400, on average, by such a cut.

The Timing of Policy Changes Needed to Meet Various Goals. In deciding how quickly to implement policies to put federal debt on a sustainable path—regardless of the chosen goal for federal debt—lawmakers face trade-offs:

- The sooner significant deficit reduction was implemented, the smaller the government's accumulated debt would be, the smaller the policy changes would need to be to achieve a particular long-term outcome, and the less uncertainty there would be about what policies would be adopted. However, if lawmakers implemented spending cuts or tax increases quickly, people would have little time to plan and adjust to the policy changes, and those changes would weaken the economic expansion over the next two years or so.

- By contrast, reductions in federal spending or increases in taxes that were implemented several years from now would have a smaller effect on output and employment in the short term. However, if lawmakers waited for some time before reducing federal spending or increasing taxes, the result would be a greater accumulation of debt, which would represent a greater drag on output and income in the long term and would increase the size of the policy changes needed to reach any chosen target for debt.

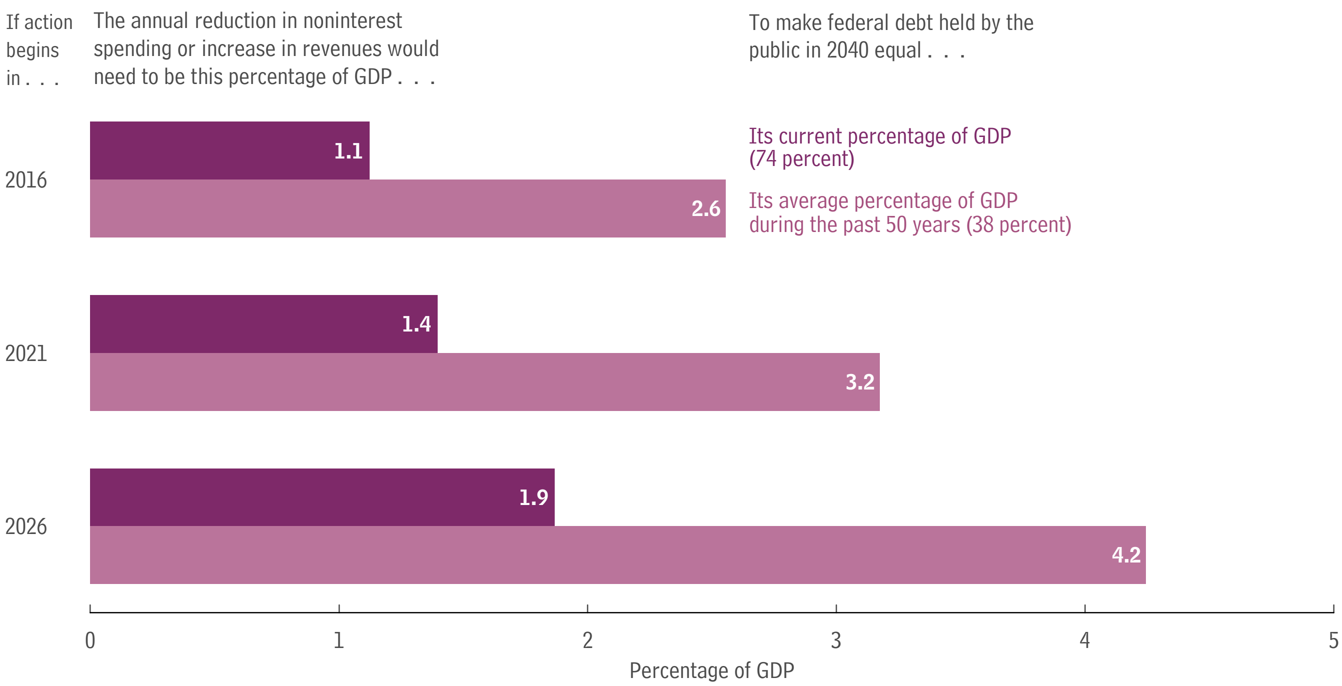
In addition, faster or slower implementation of policies to reduce budget deficits would tend to impose different burdens on different generations: Reducing deficits sooner would probably require more sacrifices by today's older workers and retirees for the benefit of today's younger workers and future generations. Reducing deficits later would require smaller sacrifices by older people and greater sacrifices by younger workers and future generations.

CBO has tried to illustrate that collection of trade-offs in three ways. First, the agency has estimated the macroeconomic consequences of several paths for federal debt in both the short term and the longer term. For example, it has analyzed the effects of phasing in deficit reduction so that, excluding interest payments, deficits would be $2 trillion lower through 2025 than under the baseline and, in subsequent years, would be reduced by the same percentage of GDP as in 2025. Under that scenario, CBO estimates, economic output would be slightly lower over the next few years but about 3 percent higher in

5. That figure is calculated in the same manner as the fiscal gap except that it uses a different target for end-of-period debt.

Figure 1-3.

The Magnitude and Timing of Policy Changes Needed to Make Federal Debt Meet Two Goals



Source: Congressional Budget Office.

Note: GDP = gross domestic product.

2040 than if current laws generally remained in effect. Those results and corresponding results for other scenarios are discussed in Chapter 6.

Second, CBO has estimated the amount by which delaying deficit reduction would increase the size of the policy adjustments needed to achieve any chosen goal for debt. For example, if the goal of lawmakers was for debt as a percentage of GDP to return to its historical average, but policy changes did not take effect until 2021, those changes would need to amount to 3.2 percent rather than 2.6 percent of GDP (see Figure 1-3). Waiting an additional five years would require even larger changes, amounting to 4.2 percent of GDP.

Third, CBO has studied how waiting to resolve the long-term fiscal imbalance would affect various generations of the U.S. population. In 2010, CBO compared economic outcomes under a policy that would stabilize the debt-to-GDP ratio starting in 2015 with outcomes under a policy that would delay stabilizing the ratio until 2025.[6] That analysis suggested that generations born after the earlier implementation date would be worse off if action to stabilize the debt-to-GDP ratio was postponed an additional 10 years. People born more than 25 years before that earlier implementation date, however, would be better off if action was delayed—largely because they would partly or entirely avoid the policy changes needed to stabilize the debt. Generations born between those two groups could either gain or lose from delayed action, depending on the details of the policy changes.[7]

Even if policy changes to reduce deficits in the long term were not implemented for several years, making decisions about them sooner rather than later would offer significant advantages. If decisions were reached sooner, people would have more time to plan and adjust their behavior to be prepared for the time when changes would be

6. See Congressional Budget Office, *Economic Impacts of Waiting to Resolve the Long-Term Budget Imbalance* (December 2010), www.cbo.gov/publication/21959. That analysis was based on a projection of slower growth in debt than CBO now projects, so the estimated effects of a similar policy today would be close, but not identical, to the effects estimated in that earlier analysis.

7. Those conclusions do not incorporate the possible negative effects of a fiscal crisis or effects that might arise from the government's reduced flexibility to respond to unexpected challenges.

implemented. In addition, decisions about policy changes that reduced future debt relative to amounts under current law would tend to increase output and employment in the next few years by holding down longer-term interest rates, reducing uncertainty, and enhancing businesses' and consumers' confidence.

Budgetary Imbalances Beyond the Next 25 Years

After 2040, the pressures of rising federal budget deficits and debt held by the public would increase further unless laws governing taxes and spending were changed. Although projections for the very long term are highly uncertain, CBO estimates that debt held by the public would be much larger relative to GDP after 75 years than it would be after 25 years. For information on CBO's projections for the very long term, see the supplemental material accompanying this report on the agency's website (www.cbo.gov/publication/50250).

Consequences of a Large and Growing Federal Debt

The high and rising amounts of federal debt held by the public that CBO projects for the coming decades under the extended baseline would have significant negative consequences for the economy in the long term and would impose significant constraints on future budget policy. In particular, the projected amounts of debt would reduce the total amounts of national saving and income in the long term; increase the government's interest payments, thereby putting more pressure on the rest of the budget; limit lawmakers' flexibility to respond to unforeseen events; and increase the likelihood of a fiscal crisis.

Less National Saving and Lower Income

Large federal budget deficits over the long term would reduce investment, resulting in lower national income and higher interest rates than would otherwise occur. Increased government borrowing would cause a larger share of the savings potentially available for investment to be used for purchasing government securities, such as Treasury bonds. Those purchases would crowd out investment in capital goods—factories and computers, for example—which would make workers less productive. Because wages are determined mainly by workers' productivity, the reduction in investment would reduce wages as well, lessening people's incentive to work. Both the government and private borrowers would face higher interest rates to compete for savings, and those rates would strengthen people's incentive to save. However, the rise in saving by households and businesses would be a good deal smaller than the increase in federal borrowing represented by the change in the deficit, so national saving—total saving by all sectors of the economy—would decline, as would private investment. (For a detailed analysis of those economic effects, see Chapter 6.)

In the short term, budget deficits would boost overall demand for goods and services, thus increasing output and employment relative to what they would be with smaller deficits or with no deficits at all. The impact of greater demand would be temporary, though, because stabilizing forces in the economy tend to push output back in the direction of its potential (or maximum sustainable) level. Those forces would include the response of prices and longer-term interest rates to greater demand and actions by the Federal Reserve.

Pressure for Larger Tax Increases or Spending Cuts

When the federal debt is large, the government ordinarily must make substantial interest payments to its lenders, and growth in the debt causes those interest payments to increase. (Net interest payments are currently fairly small relative to the size of the economy because interest rates are exceptionally low, but CBO anticipates that those payments will increase considerably as interest rates rise to their long-term levels.)

With rising debt and more normal interest rates, federal spending on interest payments would rise, thus requiring higher taxes, lower spending for benefits and services, or both to achieve any chosen targets for budget deficits and debt. If taxes were increased by raising marginal tax rates (the rates that apply to an additional dollar of income), those higher rates would discourage people from working and saving, thus further reducing output and income. Alternatively, lawmakers could choose to offset higher interest costs at least in part by reducing government benefits and services. Those reductions could be made in many ways, but to the extent that they came from cutting federal investments, future output and income also would be reduced. As another option, lawmakers could respond to higher interest payments by allowing deficits to increase for some period, but that approach would require greater deficit reduction later if lawmakers wanted to avoid a long-term increase in the debt-to-GDP ratio.

Reduced Ability to Respond to Domestic and International Problems

When the amount of outstanding debt is relatively small, a government can borrow money to address significant unexpected events—recessions, financial crises, or wars, for example. In contrast, when outstanding debt is large, a government has less flexibility to address financial and economic crises, which can be very costly for many countries.[8] A large amount of debt also can compromise a country's national security by constraining military spending in times of international crisis or by limiting the country's ability to prepare for such a crisis.

Several years ago, when federal debt was below 40 percent of GDP, the government had some flexibility to respond to the financial crisis and severe recession by increasing spending and cutting taxes to stimulate economic activity, providing public funding to stabilize the financial sector, and continuing to pay for other programs even as tax revenues dropped sharply because of the decline in output and income. As a result, federal debt almost doubled as a percentage of GDP. If federal debt stayed at its current percentage of GDP or increased further, the government would find it more difficult to undertake similar policies under similar conditions in the future. As a result, future recessions and financial crises could have larger negative effects on the economy and on people's well-being. Moreover, the reduced financial flexibility and increased dependence on foreign investors that accompany high and rising debt could weaken U.S. leadership in the international arena.

Greater Chance of a Fiscal Crisis

A large and continuously growing federal debt would have another significant negative consequence: It would increase the likelihood of a fiscal crisis in the United States.[9] Specifically, there would be a greater risk that investors would become unwilling to finance the government's borrowing needs unless they were compensated with very high interest rates; as a result, interest rates on federal debt would rise suddenly and sharply relative to rates of return on other assets. That increase in interest rates would reduce the market value of outstanding government bonds, causing losses for investors and perhaps precipitating a broader financial crisis by creating losses for mutual funds, pension funds, insurance companies, banks, and other holders of government debt—losses that might be large enough to cause some financial institutions to fail. A fiscal crisis can also make private-sector borrowing more expensive because uncertainty about the government's responses can reduce confidence in the viability of private-sector enterprises. Higher private-sector interest rates, when combined with reduced government spending and increased taxes, have tended to worsen economic conditions in the short term.

Unfortunately, predicting with any confidence whether or when such a fiscal crisis might occur in the United States is not possible. In particular, there is no identifiable tipping point in the debt-to-GDP ratio to indicate that a crisis is likely or imminent. All else being equal, however, the larger a government's debt, the greater the risk of a fiscal crisis.

The likelihood of such a crisis also depends on economic conditions. If investors expect continued economic growth, they are generally less concerned about the government's debt burden; conversely, substantial debt can reinforce more generalized concern about an economy. Thus, in many cases around the world, fiscal crises have begun during recessions—and, in turn, have exacerbated them. In some instances, a crisis has been triggered by news that a government would need to borrow an unexpectedly large amount of money. Then, as investors lost confidence and interest rates spiked, borrowing became more expensive for the government.

If a fiscal crisis were to occur in the United States, policymakers would have only limited—and unattractive—options for responding. In particular, the government would need to undertake some combination of three approaches: restructure the debt (that is, seek to modify the contractual terms of existing obligations), pursue an inflationary monetary policy, and adopt an austerity program of spending cuts and tax increases. Thus, such a crisis would confront policymakers with extremely difficult choices and probably have a significantly negative effect on the country.

8. See, for example, Carmen M. Reinhart and Kenneth S. Rogoff, "The Aftermath of Financial Crises," *American Economic Review*, vol. 99, no. 2 (May 2009), pp. 466–472, http://tinyurl.com/ml9kchv; and Carmen M. Reinhart and Vincent R. Reinhart, "After the Fall," *Macroeconomic Challenges: The Decade Ahead* (Federal Reserve Bank of Kansas City, 2010), http://tinyurl.com/lntnp6j (PDF, 1.6 MB). Also see Luc Laeven and Fabian Valencia, *Systemic Banking Crises Database: An Update*, Working Paper 12-163 (International Monetary Fund, June 2012), http://tinyurl.com/p2clvmy.

9. For additional discussion, see Congressional Budget Office, *Federal Debt and the Risk of a Fiscal Crisis* (July 2010), www.cbo.gov/publication/21625.

CBO's Approach to Producing Long-Term Projections

Under the extended baseline, CBO's assumptions about policies governing federal spending and revenues generally reflect current law, incorporating the same assumptions underlying the agency's 10-year baseline through 2025 and then extending the baseline concept to later years. To formulate its extended baseline, CBO projects demographic and economic conditions for the decades ahead and develops assumptions about future policies for the major categories of federal spending and revenues. The set of projected demographic and economic conditions, which CBO refers to as its economic benchmark, is consistent with CBO's 10-year baseline projections, as adjusted for recently enacted legislation, and reflects CBO's assessment of long-term demographic and economic trends thereafter; instead of incorporating the changes in federal debt and tax rates under the extended baseline, the economic benchmark incorporates the assumption that federal debt as a share of GDP and marginal tax rates remain constant at their 2025 levels in subsequent years. (That approach produces a relatively stable economic benchmark, which is described more fully in Appendix A.) Because the long-term projections of federal spending, revenues, and debt presented in this and the next four chapters reflect the relatively stable economic conditions underlying the economic benchmark, those projections do not incorporate the economic effects of rising debt beyond 2025 or possible changes to fiscal policies; those considerations are addressed in Chapters 6 and 7.

Economic Projections

Economic growth will be slower in the future than it has been in the past, CBO projects, largely because of a slowdown in the growth of the labor force resulting from the retirement of members of the baby-boom generation, declining birthrates, and the leveling-off of increases in women's participation in the labor market. The labor force is projected to grow at an average annual rate of 0.5 percent over the next 25 years, compared with the 1.7 percent recorded during the 1965–2007 period.[10] CBO projects that future productivity growth will be close to its historical average. Accounting for those and other economic variables, CBO projects that real (inflation-adjusted) GDP will increase at an average annual rate of 2.2 percent over the next 25 years, compared with 3.3 percent during the 1965–2007 period.

In the economic benchmark—where debt as a percentage of GDP is assumed to remain constant at the 2025 level—CBO projects that interest rates will rise from the unusually low levels in effect today but still be lower in the future than they have been, on average, during the past few decades. According to CBO's most recent economic projection for the next decade, the real interest rate (specifically, the interest rate after adjusting for the rate of increase in the consumer price index) on 10-year Treasury notes is projected to rise to 2.2 percent for the 2020–2025 period. After 2025, it is projected to rise to 2.3 percent and remain at that level, below its average of 3.1 percent over both the 1965–2007 and 1990–2007 periods.[11]

The average interest rate on all federal debt held by the public tends to be a little lower than the rate on 10-year Treasury notes because interest rates are generally lower on shorter-term debt than on longer-term debt; and, since the 1950s, the average maturity of federal debt has been shorter than 10 years. CBO projects that the average real interest rate on all federal debt held by the public will be 2.0 percent after 2025.

For the 2015–2040 period, the real interest rate on 10-year Treasury notes is projected to average 2.2 percent, and the rate for all federal debt held by the public is projected to average 1.5 percent. The average interest rate on federal debt is projected to rise more slowly than rates on 10-year Treasury notes because only a portion of federal debt matures each year.

If those figures for real interest rates were adjusted instead to reflect the rate of increase in the GDP price index (or the price index for personal consumption expenditures), the real interest rate on all federal debt held by the public over the next 25 years would average 1.9 percent. Thus, during the next 25 years as a whole, the growth rate of GDP—at 2.2 percent—is projected to exceed the average real interest rate on federal debt. (Beyond 2025, the

10. In its assessment of historical experience, CBO has excluded the years that have elapsed since 2007 because of the effects of the recession.

11. For comparisons of historical real rates, past values of the consumer price index were based on the Consumer Price Index Research Series Using Current Methods from the Bureau of Labor Statistics; that series accounts for changes over time in how that index measures inflation.

average interest rate on federal debt is projected to be only slightly higher than the growth rate of GDP.) When the interest rate is about the same as the growth rate of GDP, the ratio of debt to GDP would remain steady over time if the federal budget, excluding interest payments, was in balance.

Policy Assumptions

Under CBO's extended baseline, projections for the 2016–2025 period are identical to those in the agency's 10-year baseline, as adjusted for recently enacted legislation. For later years, the extended baseline generally follows the baseline concept (see Table 1-1 for a summary of CBO's policy assumptions).

Major Health Care Programs. CBO projects federal spending for the government's major health care programs—Medicare, Medicaid, the Children's Health Insurance Program, and insurance subsidies provided through the exchanges created under the ACA—for 2015 through 2025 under the assumption that there will generally be no changes to laws currently governing those programs. (Unless otherwise specified, Medicare outlays are presented net of offsetting receipts, mostly premiums paid by enrollees, which reduce net outlays for that program.)

Beyond 2025, the considerable uncertainty that surrounds the evolution of the health care delivery and financing systems leads CBO to employ a formulaic approach in its projections of federal spending for health care programs. Specifically, CBO combines estimates of the number of people who will be receiving benefits from the government's health care programs with fairly mechanical estimates of the growth in spending per beneficiary. (See Chapter 2 for details about the long-term projections for the major health care programs; CBO assumes that Medicare will pay benefits as scheduled under current law regardless of the status of the program's trust funds—an assumption that is consistent with a statutory requirement that, in its 10-year baseline projections, CBO assume that funding for entitlement programs is adequate to make all payments required by law.)[12]

Social Security. CBO projects spending for Social Security under the assumption that there will be no changes to laws currently governing that program. The agency also assumes that Social Security will pay benefits as scheduled under current law regardless of the status of the program's trust funds.[13] (For more on Social Security, see Chapter 3.)

Other Mandatory Programs. For other mandatory programs—such as retirement programs for federal civilian and military employees, certain veterans' programs, the Supplemental Nutrition Assistance Program (SNAP), unemployment compensation, and refundable tax credits—the projections through 2025 are based on the assumption that current law will remain generally unchanged.[14] For years after 2025, CBO projects outlays for refundable tax credits as part of its revenue projections and projects spending for the remaining mandatory programs as a whole by assuming that such spending will decline as a share of GDP after 2025 at the same annual rate that it is projected to fall between 2020 and 2025. That is, CBO does not estimate outlays for each program separately after 2025 (see Chapter 4).

Discretionary Spending. Discretionary spending in the extended baseline matches that in the 10-year baseline through 2025. Under current law, most of the government's discretionary appropriations for the 2015–2021 period are constrained by the caps put in place by the Budget Control Act of 2011, as amended. For 2022 through 2025, those appropriations are assumed to grow from the 2021 amount at the rate of anticipated inflation. Funding for certain purposes, such as war-related activities, is not constrained by the caps; CBO assumes that such funding will increase each year through 2025 at the rate of inflation, starting from the amount appropriated for the current year. After 2025, discretionary spending is assumed to remain fixed at its percentage of GDP in 2025 (see Chapter 4).

Revenues. Revenue projections through 2025 follow the 10-year baseline, which generally incorporates the

12. Section 257(b)(1) of the Balanced Budget and Emergency Deficit Control Act of 1985, 2 U.S.C. §907(b)(1).

13. The balances of the trust funds represent the total amount that the government is legally authorized to spend for those purposes. For a discussion of the legal issues related to exhaustion of a trust fund, see Noah P. Meyerson, *Social Security: What Would Happen If the Trust Funds Ran Out?* Report for Congress RL33514 (Congressional Research Service, August 28, 2014).

14. The law governing CBO's baseline projections (section 257(b)(2) of the Deficit Control Act) makes exceptions for some programs, such as SNAP, that have expiring authorizations but that are assumed to continue as currently authorized.

Table 1-1.

Assumptions About Policies for Spending and Revenues Underlying CBO's Extended Baseline

	Assumptions About Policies for Spending
Social Security	As scheduled under current law[a]
Medicare	As scheduled under current law through 2025; thereafter, projected spending depends on the estimated number of beneficiaries and health care costs per beneficiary (for which growth is projected to move smoothly to the underlying path of excess cost growth rates over the succeeding 15 years and then follow that path)[a]
Medicaid	As scheduled under current law through 2025; thereafter, projected spending depends on the estimated number of beneficiaries and health care costs per beneficiary (for which growth is projected to move smoothly to the underlying path of excess cost growth rates over the succeeding 15 years and then follow that path)
Children's Health Insurance Program	As projected in CBO's baseline through 2025; remaining constant as a percentage of GDP thereafter
Exchange Subsidies	As scheduled under current law through 2025; thereafter, projected spending depends on the estimated number of beneficiaries, an additional indexing factor for subsidies, and health care costs per beneficiary (for which growth is projected to move smoothly to the underlying path of excess cost growth rates over the succeeding 15 years and then follow that path)
Other Mandatory Spending	As scheduled under current law through 2025; thereafter, refundable tax credits are estimated as part of revenue projections, and the rest of other mandatory spending is assumed to decline as a percentage of GDP at the same annual rate at which it is projected to decline between 2020 and 2025
Discretionary Spending	As projected in CBO's baseline through 2025; remaining constant as a percentage of GDP thereafter
	Assumptions About Policies for Revenues
Individual Income Taxes	As scheduled under current law
Payroll Taxes	As scheduled under current law
Corporate Income Taxes	As scheduled under current law through 2025; remaining constant as a percentage of GDP thereafter
Excise Taxes	As scheduled under current law[b]
Estate and Gift Taxes	As scheduled under current law
Other Sources of Revenues	As scheduled under current law through 2025; remaining constant as a percentage of GDP thereafter

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

For CBO's most recent 10-year baseline projections, see Congressional Budget Office, *Updated Budget Projections: 2015 to 2025* (March 2015), www.cbo.gov/publication/49973.

GDP = gross domestic product.

a. Assumes the payment of full benefits as calculated under current law, regardless of the amounts available in the program's trust funds.

b. The sole exception to the current-law assumption applies to expiring excise taxes dedicated to trust funds. The Balanced Budget and Emergency Deficit Control Act of 1985 requires CBO's baseline to reflect the assumption that those taxes would be extended at their current rates. That law does not stipulate that the baseline include the extension of other expiring tax provisions, even if they have been routinely extended in the past.

assumption that various tax provisions will expire as scheduled even if they have routinely been extended in the past. After 2025, rules for individual income taxes, payroll taxes, excise taxes, and estate and gift taxes are assumed to evolve as scheduled under current law.[15] Because of the structure of current tax law, total federal revenues from those sources are estimated to grow faster than GDP over the long term. Revenues from corporate income taxes and other sources (such as receipts from the Federal Reserve) are assumed to remain constant as a percentage of GDP after 2025 (see Chapter 5).

Projected Spending Through 2040

Over the past 50 years, federal outlays other than those for the government's net interest costs have averaged 18 percent of GDP. However, in the past several years, noninterest spending has been well above that average, both because of underlying trends and because of temporary circumstances (namely, the financial crisis, the weak economy, and policies implemented in response to them). Noninterest spending spiked to 23 percent of GDP in 2009 but then declined, falling to about 19 percent this year. If current laws that affect spending were unchanged, noninterest outlays would remain at about 19 percent of GDP throughout the coming decade, CBO projects, as an increase in mandatory spending was offset by a decline in discretionary spending relative to the size of the economy. After the mid-2020s, however, under the assumptions of the extended baseline, noninterest spending would rise relative to the size of the economy, mostly because of increased spending for major health care programs, reaching 21 percent of GDP by 2040.

CBO projects that, under current law, net outlays for interest would jump from 1.3 percent of GDP this year to almost 3 percent 10 years from now. By 2040, interest costs would be 4.3 percent of GDP, bringing total federal spending to over 25 percent of GDP (see Figure 1-4). Federal spending has been larger relative to the size of the economy only during World War II, when it topped 40 percent of GDP for three years.

15. The sole exception to that current-law assumption applies to expiring excise taxes dedicated to trust funds. The Deficit Control Act requires CBO's baseline to reflect the assumption that those taxes would be extended at their current rates. That law does not stipulate that the baseline include the extension of other expiring tax provisions, even if they have been routinely extended in the past.

Spending for Major Health Care Programs and Social Security

Mandatory programs have accounted for a rising share of the federal government's noninterest spending over the past few decades, reaching more than 60 percent in recent years. Most of the growth in mandatory spending has involved the three largest programs—Medicare, Medicaid, and Social Security. Federal outlays for those programs together made up almost half of the government's noninterest spending, on average, during the past 10 years, compared with less than a sixth five decades ago.

Most of the anticipated growth in noninterest spending as a share of GDP over the long term is expected to come from the government's major health care programs: Medicare, Medicaid, the Children's Health Insurance Program, and the subsidies for health insurance purchased through the exchanges created under the ACA. CBO projects that, under current law, total outlays for those programs over the next 25 years, net of offsetting receipts, would grow much faster than the overall economy, increasing from 5.2 percent of GDP now to 8.0 percent in 2040 (see Chapter 2). Spending for Social Security also would increase relative to the size of the economy, but by much less—from 4.9 percent of GDP in 2015 to 6.2 percent in 2040 and beyond (see Chapter 3).

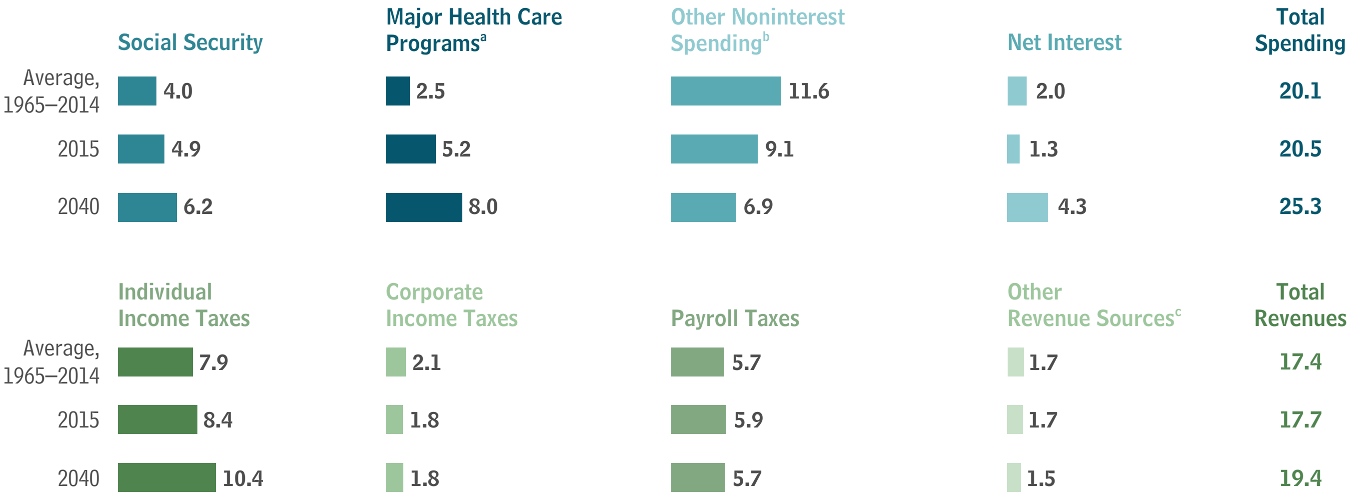
Those projected increases in spending for the government's major health care programs and Social Security between 2015 and 2040 are attributable primarily to three causes: the aging of the population; rising health care spending per beneficiary; and, to a lesser extent, an increased number of recipients of exchange subsidies and Medicaid benefits attributable to the ACA. (For estimates of the extent to which each cause contributes to the projected increases in spending, see Box 1-1 on page 24.)

The Aging of the Population. The retirement of members of the baby-boom generation portends a long-lasting shift in the age profile of the U.S. population—a change that will substantially alter the balance between working-age and retirement-age groups. During the next decade alone, the number of people age 65 or older is expected to rise by more than one-third, and the share of the population age 65 or older is projected to grow from the current 15 percent to 21 percent in 2040. By contrast, the share of the population between the ages of 20 and 64 is expected to drop from 59 percent to 54 percent.

Figure 1-4.

Spending and Revenues Under CBO's Extended Baseline, Compared With Past Averages

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

a. Consists of spending on Medicare (net of offsetting receipts), Medicaid, the Children's Health Insurance Program, and subsidies offered through health insurance exchanges.

b. Consists of all federal spending other than that for the major health care programs, Social Security, and net interest.

c. Consists of excise taxes, remittances to the Treasury from the Federal Reserve System, customs duties, estate and gift taxes, and miscellaneous fees and fines.

The aging of the population is the main factor driving the projected growth of Social Security spending as a percentage of GDP. Initial Social Security benefits are based on a person's earnings history, but those earnings are indexed to the overall growth of wages in the economy, so average benefits increase at approximately the same rate as average earnings. As a result, economic growth does not significantly alter spending for Social Security as a share of GDP. Rather, that share depends primarily on the ratio of the number of people working in jobs covered by Social Security (covered workers) to the number of Social Security beneficiaries. CBO projects that the ratio of covered workers to beneficiaries will decline significantly over the next quarter century—from 3 to 1 now to almost 2 to 1 in 2040—and then continue to drift downward.

Rising Health Care Spending per Beneficiary. Although the growth of health care spending has been slower during the past several years than it had been historically, CBO projects that per-enrollee spending in federal health care programs will continue to increase at a faster pace than potential GDP per capita over the next 25 years. The growth rate of spending per beneficiary in Medicare and Medicaid is projected to remain very low over the next few years but is then projected to increase gradually through 2040 (although remaining below its average growth rate of the past few decades). Compared with Medicare and Medicaid, costs per enrollee in private insurance are expected to grow more rapidly over the coming decade, but CBO projects a gradual slowing in later years. Although costs per beneficiary in federal health care programs are projected to increase faster than potential GDP per capita over the 25-year projection period, the difference between those two growth rates will be smaller than its average of recent decades, CBO projects (see Chapter 2).

Increased Number of Recipients of Exchange Subsidies and Medicaid Benefits. Under the ACA, many people can purchase subsidized insurance through the health insurance exchanges (or marketplaces) that are operated by the federal or state governments. Those subsidies come in two forms: refundable tax credits that can be applied to premiums, and cost-sharing subsidies that reduce deductibles and copayments. CBO anticipates that the number of participants will increase over the next few years and that between 16 million and 17 million people will receive subsidized health insurance coverage through the exchanges in each year between 2019 and 2025, compared with 8 million now.[16] Also, several million others will obtain unsubsidized coverage through the exchanges.

In addition, as a result of the ACA and a subsequent Supreme Court ruling, each state has the option to expand eligibility for Medicaid to most nonelderly adults whose income is below 138 percent of the federal poverty guidelines (commonly known as the federal poverty level, or FPL).[17] By calendar year 2020, CBO anticipates, 80 percent of the people who meet the new eligibility criteria will live in states that will have expanded their programs.[18] Each year between 2020 and 2025, about 14 million more people, on net, are projected to have coverage through Medicaid than would have had such coverage in the absence of the ACA, compared with 10 million more now.

Other Noninterest Spending

In the extended baseline, total federal spending for everything other than the major health care programs, Social Security, and net interest declines to a smaller percentage of GDP than has been the case for more than 70 years. Such spending has amounted to more than 8 percent of GDP each year since the 1930s, reaching as much as 13 percent of GDP in 1965 and 12 percent in 1990; CBO estimates that it will be 9.1 percent of GDP in 2015. Under the assumptions used for this analysis, that spending is projected to fall below 8 percent of GDP in 2021 and then to decline further, dropping to 6.9 percent of GDP in 2040 (see Chapter 4).

Spending for discretionary programs is projected to decline significantly over the next 10 years relative to GDP—from 6.5 percent to 5.1 percent—because of the constraints on discretionary funding imposed by the Budget Control Act. For its long-term projections, CBO assumed that, in subsequent years, discretionary outlays would remain at the share of GDP projected for 2025.

Spending for mandatory programs other than the major health care programs and Social Security also is projected to decline relative to the size of the economy over the next 10 years. That spending accounts for 2.6 percent of GDP today and, under current law, is projected to fall to 2.3 percent of GDP in 2025. That decline would occur in part because the improving economy would reduce the number of people eligible for some programs in this category and in part because payments per beneficiary under some programs tend to rise with prices (which usually increase more slowly than people's income). Beyond 2025, CBO projects, other mandatory spending, excluding the portion stemming from refundable tax credits, would decline as a share of GDP at the same annual rate at which it is projected to fall between 2020 and 2025. As a result, other mandatory spending would fall to 1.8 percent of GDP by 2040—lower than at any point at least since 1962 (the first year for which comparable data are available).

Interest Payments

CBO expects interest rates to rebound in coming years from their current unusually low levels. As a result, the government's net interest costs are projected to more than double relative to the size of the economy over the next decade—from 1.3 percent of GDP in 2015 to 3.0 percent by 2025—even though, under current law, federal debt would be only slightly larger relative to GDP at the end of that decade than it is today.

Beyond 2025, interest rates in the economic benchmark are assumed to increase only slightly from their projected levels in 2025, so changes in net interest costs would roughly parallel changes in the amount of federal debt held by the public. By 2040, those costs would reach 4.3 percent of GDP under current law. Growth in net interest payments and growth in debt are mutually reinforcing: Rising interest payments push up deficits and debt, and rising debt pushes up interest payments.

16. See Congressional Budget Office, *Effects of the Affordable Care Act on Health Insurance Coverage—Baseline Projections* (March 2015), Table 3, www.cbo.gov/publication/43900.

17. The ACA expanded eligibility for Medicaid to include nonelderly residents with income of up to 133 percent of the FPL, but the law defines the income used to determine eligibility in a way that effectively increases that threshold to 138 percent of the FPL. The FPL is currently $24,250 for a family of four. See Department of Health and Human Services, Office of the Assistant Secretary for Planning and Evaluation, "2015 Poverty Guidelines" (January 2015), http://aspe.hhs.gov/poverty/15poverty.cfm. As a result of the Supreme Court's decision on June 28, 2012, in *National Federation of Independent Business v. Sebelius,* 132 S. Ct. 2566 (2012), some states may choose not to expand their programs.

18. See Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), p. 69, www.cbo.gov/publication/49892.

Box 1-1.

Causes of Projected Growth in Federal Spending for the Major Health Care Programs and Social Security

Under its extended baseline, the Congressional Budget Office projects that the growth of federal noninterest spending as a share of gross domestic product (GDP) between 2015 and 2040 would result entirely from increases in spending for four large mandatory programs—Medicare, Medicaid, the subsidies provided through the health insurance exchanges established under the Affordable Care Act (ACA), and Social Security.[1] The health care programs currently account for about half of the overall spending for those four programs, and they would be responsible for more than two-thirds of the projected increase in such spending over the next 25 years. (By contrast, under the assumptions that govern the extended baseline, total federal spending on everything other than those four programs and net interest is projected to fall significantly as a percentage of GDP over the next 25 years.)

Three factors underlie the projected increase in federal spending for the health care programs and Social Security relative to the size of the economy:

- The aging of the U.S. population, which will increase the share of the population receiving benefits from those programs and also affect the average age, and thus the average health care costs, of beneficiaries;
- The effects of excess cost growth—that is, the extent to which health care costs per beneficiary, as adjusted for demographic changes, grow faster than potential GDP per capita;[2] and
- The increase, beyond that which has occurred through 2015, in enrollment in Medicaid under the ACA and in the number of people receiving subsidies for health insurance purchased through the exchanges.

CBO calculated how much of the projected growth in federal spending for the major health care programs and Social Security over the 2015–2040 period could be attributed to each of the three factors. (Of those factors, aging is the only one that affects CBO's projections for Social Security.) The agency compared the outlays projected for those programs under the extended baseline with the outlays that would occur under three alternative paths, each of which includes no increase in the number of recipients of exchange subsidies and Medicaid benefits attributable to the ACA: One included aging of the population but no excess cost growth; one included excess cost growth but no aging of the population; and one included both aging and excess cost growth.

The ways in which the aging of the population and excess cost growth interact accentuate those factors' individual effects. For example, as aging causes the number of Medicare beneficiaries to increase, rising health care spending per person has a greater impact on federal spending for health care. Likewise, when per-person health care costs rise, the increasing number of beneficiaries has greater budgetary consequences. The effect of that interaction can be identified separately—or, as in CBO's analysis, it can be allocated in proportion to the shares of projected growth that are attributable to the two factors: aging and excess cost growth.

1. The Children's Health Insurance Program, which is usually grouped with major federal health care programs in CBO's long-term projections, is not included in this analysis of the causes of projected growth.

2. Potential GDP is the economy's maximum sustainable output.

Continued

Projected Revenues Through 2040

Over the past 50 years, federal revenues as a share of GDP have averaged 17.4 percent—fluctuating between 14.6 percent and 20 percent of GDP—with no evident trend over time. After amounting to 17.9 percent of GDP in 2007, federal revenues fell sharply in 2009, to 14.6 percent of GDP, primarily because of the recession. With an improving economy and changes in certain tax rules that have resulted in higher tax rates, revenues will rebound to 17.7 percent of GDP in 2015, CBO estimates.

Box 1-1. **Continued**

Causes of Projected Growth in Federal Spending for the Major Health Care Programs and Social Security

Explaining Projected Growth in Federal Spending for the Major Health Care Programs and Social Security as a Share of GDP

	Percentage of Projected Growth Through 2025	2040
	Major Health Care Programs and Social Security	
Aging	62	56
Excess Cost Growth	17	35
Increased Number of Recipients of Exchange Subsidies and Medicaid Benefits Attributable to the ACA	21	10
	Major Health Care Programs	
Aging	42	43
Excess Cost Growth	26	45
Increased Number of Recipients of Exchange Subsidies and Medicaid Benefits Attributable to the ACA	32	12

Source: Congressional Budget Office.

Note: ACA = Affordable Care Act; GDP = gross domestic product.

The aging of the population and excess cost growth also affect the budgetary impact of the additional recipients of exchange subsidies and Medicaid benefits attributable to the ACA but in different directions: Excess cost growth increases the effect of the increased number of recipients on federal health care spending, but aging decreases the effect by reducing the share of the population that is under the age of 65 and, therefore, potentially eligible for the expanded federal benefits.

According to CBO's calculations, the aging of the population accounts for 56 percent of the projected growth in federal spending for the major health care programs and Social Security as a share of GDP through 2040 (see the table). Excess cost growth accounts for 35 percent, and the increased number of recipients of exchange subsidies and Medicaid benefits attributable to the ACA accounts for the remaining 10 percent. (For more information about CBO's projections of demographic changes over the 25-year period, see Figure 2-3 on page 45; for more information about excess cost growth and spending on federal health care programs, see Chapter 2.)

For the major health care programs alone, the relative impact of the population's aging is smaller, and the significance of factors related to health care is greater. Through 2040, aging accounts for 43 percent of projected growth in federal spending for those programs as a share of GDP, excess cost growth accounts for 45 percent, and the increased number of recipients of exchange subsidies and Medicaid benefits attributable to the ACA together account for 12 percent; most of that growth is projected to occur during the next few years. Total federal spending for those programs would increase from 5.2 percent of GDP in 2015 to 8.0 percent in 2040 under current law, CBO projects. Of that 2.8 percentage-point increase, aging would contribute 1.2 percentage points; excess cost growth, 1.3 percentage points; and the increased number of recipients of the exchange subsidies and Medicaid benefits attributable to the ACA, 0.3 percentage points.

Individual income taxes account for the bulk of federal revenues, almost half of all revenues in 2014; payroll taxes (also known as social insurance taxes) account for about one-third of all revenues; and corporate income taxes and excise taxes account for most of the remainder.[19]

CBO projects that, under current law, revenues would grow over the coming decade relative to GDP—to 18.3 percent of GDP in 2025. Individual income taxes would rise as a percentage of GDP largely because of structural features of the tax system, most significantly, real bracket creep—the pushing of a growing share of income into higher tax brackets because of a growth in real (inflation-adjusted) income and the interaction of the tax system with inflation. That increase would be

19. Most payroll tax revenues come from taxes designated for Social Security and Medicare; the rest come mainly from taxes for unemployment insurance.

partially offset by declines in other taxes relative to GDP, most notably receipts from the Federal Reserve.

Over the long term, revenues would keep growing slightly more rapidly than GDP under current law, as the effect of real bracket creep continues and certain tax increases enacted in the ACA generate a growing amount of revenues in relation to the size of the economy. By 2040, total revenues would be 19.4 percent of GDP, CBO projects. Increases in receipts from individual income taxes account for more than the 1.7 percentage-point rise in total revenues as a percentage of GDP over the next 25 years; receipts from all other sources, taken together, are projected to decline slightly as a percentage of GDP (see Chapter 5).

Even if no changes in tax law were enacted in the future, the effects of the tax system in 2040 would differ in significant ways from what those effects are today. Average taxpayers at all income levels would pay a greater share of income in taxes than similar taxpayers do now, primarily because a greater share of their income would be taxed in higher tax brackets. Moreover, the effective marginal tax rate on labor income (the percentage of an additional dollar of labor income paid in federal taxes) would be about 32 percent, compared with the current 29 percent. In contrast, the effective marginal tax rate on capital income (the percentage of an additional dollar of income from investments paid in federal taxes) would rise only slightly and remain close to 18 percent.

Changes From Last Year's Long-Term Budget Outlook

Each time it prepares long-term budget projections, CBO incorporates the effects of new legislation and updates the economic and technical aspects of its projections. The projections of federal revenues and overall noninterest outlays presented in this report are generally similar to those published in 2014, despite certain changes in law, revisions to some of the agency's assumptions and methods, and the availability of more recent data.[20] A downward revision to the projections for interest rates has lowered the projection for net interest costs and, as a result, CBO projects slightly lower debt in 2040 than the agency projected last year. That same downward revision to the projections for interest rates and some other changes have led CBO to estimate a smaller fiscal gap and a greater actuarial deficit for Social Security. (The key revisions to the projections since last year are discussed in Appendix B.)

Taken together, legislative, economic, and technical changes had the following effects on CBO's view of the federal budget in the long term:

- Under the extended baseline, CBO now projects that debt would reach 101 percent of GDP in 2039, compared with a projection last year of 106 percent. (Those figures do not incorporate feedback from the economic impact of those paths for federal debt; with such feedback considered, debt in 2039 is now projected to grow to 105 percent of GDP, compared with the 111 percent projected last year.)

- The estimated fiscal gap is smaller this year than last year. For the 2016–2040 period, CBO now estimates that cuts in noninterest spending or increases in revenues equal to 1.1 percent of GDP in each year through 2040 would be required to have debt in 2040 equal the same percentage of GDP that it constitutes today; last year, for the 2015–2039 period, CBO estimated that changes equal to 1.2 percent of GDP would be required. By itself, the reduction in projected interest rates on federal debt would have brought the gap down by 0.3 percent of GDP, but changes in projected GDP and the shift in the projection period offset most of that effect.

- The actuarial shortfall for the Social Security trust funds is estimated to be larger this year than was estimated last year. The estimated actuarial balance for Social Security is the sum of the present value of projected tax revenues and the trust funds' current balance minus the sum of the present value of projected outlays and a target balance at the end of the period; that difference is traditionally presented as a percentage of the present value of taxable payroll. CBO now estimates that the 75-year actuarial deficit for Social Security is 4.4 percent of taxable payroll, compared with the previous projection of 4.0 percent. That change reflects the reduction in projected interest rates, lower payroll tax revenues resulting from a lower projection of the taxable share of earnings, updated data, and other factors (see Chapter 3 and Appendix B).

20. For CBO's long-term projections for the 2014–2039 period, see Congressional Budget Office, *The 2014 Long-Term Budget Outlook* (July 2014), www.cbo.gov/publication/45471.

CHAPTER

2

The Long-Term Outlook for Major Federal Health Care Programs

Although spending for health care in the United States has grown more slowly in recent years than it did previously, high and rising amounts of such spending continue to pose a challenge not only for the federal government but also for state and local governments, businesses, and households. Total national spending on health care services and supplies—that is, by all people and entities in the United States, governmental and nongovernmental—increased from 4.6 percent of gross domestic product (GDP) in calendar year 1960 to 9.5 percent in 1985 and to 16.4 percent, about one-sixth of the economy, in 2013, the most recent year for which such data are available.[1] Federal spending for Medicare (net of certain receipts, termed offsetting receipts, which mostly consist of premiums paid by beneficiaries) and Medicaid rose from 2.0 percent of GDP in 1985 to 4.7 percent in 2014.[2]

Underlying those trends is the fact that health care spending per person has grown faster, on average, than the nation's economic output per capita during the past few decades. The Congressional Budget Office estimates that growth in health care spending per person outpaced growth in potential (or maximum sustainable) GDP per capita by an average of 1.4 percent per year between calendar years 1985 and 2013.[3] Key factors contributing to that faster growth were the emergence and increasing use of new medical technologies, rising personal income, and the declining share of health care costs that people paid out of pocket. Those factors were partly offset by other influences, including the spread of managed care plans in the 1990s, the 2007–2009 recession, and various legislated changes in Medicare's payment policies.

The future growth of health care spending by the federal government will depend on many factors, including demographic changes and the behavior of households, businesses, and state and local governments. (It will also depend on federal law, but CBO's extended baseline projections, which focus on the 25-year period ending in 2040, are generally based on the assumption that current law will not change.) CBO's extended baseline projections of federal health care spending match its 10-year baseline projections as adjusted to reflect recently enacted legislation for the next 10 years but employ a formulaic approach beyond that period, reflecting the considerable uncertainties about the evolution of the health care delivery and financing systems in the long run.[4] Specifically, CBO has projected federal spending after 2025 by

1. Centers for Medicare & Medicaid Services, National Health Expenditure Accounts, "NHE Tables" (accessed April 3, 2015), http://go.usa.gov/jmGY.

2. In this chapter, net federal spending for Medicare refers to gross spending for Medicare minus offsetting receipts, which are recorded in the budget as offsets to spending. When this chapter refers to net federal spending for *all* major federal health care programs, it means gross spending for all those programs minus offsetting receipts for Medicare.

3. As this chapter explains later, CBO derived that estimate after adjusting for demographic changes and giving greater weight to more recent years (in order to more closely reflect current trends in spending for health care).

4. The 10-year baseline referred to in this chapter is the one issued in March 2015, but adjusted to reflect legislation that was enacted after it was prepared. For the March baseline, see Congressional Budget Office, *Updated Budget Projections: 2015 to 2025* (March 2015), www.cbo.gov/publication/49973. The most important adjustment to that baseline was the incorporation of the estimated effect of Public Law 114-10, the Medicare Access and CHIP Reauthorization Act of 2015, which became law on April 16, 2015. See Congressional Budget Office, cost estimate for H.R. 2, the Medicare Access and CHIP Reauthorization Act of 2015 (March 25, 2015), www.cbo.gov/publication/50053.

combining estimates of the number of people who will receive benefits from government health care programs with fairly mechanical estimates of the growth of spending per beneficiary:

- Under current law, the first of those factors—the number of people receiving benefits from government programs—is projected to increase during the next few decades. That increase can be attributed to two main causes. The first is the aging of the population—in particular, of the large baby-boom generation—which will increase the number of people receiving benefits from Medicare by about one-third over the next decade. The second is the projected increase over the next few years in the number of people who will enroll in Medicaid or receive federal subsidies for health insurance purchased through exchanges under the provisions of the Affordable Care Act (ACA).

- The second factor in CBO's projections of federal spending, the growth of spending per beneficiary in most of the major health care programs, is projected to move slowly from the average rate projected for the years 2023 through 2025 (with certain adjustments) to what CBO considers its underlying growth rate.[5] Each program's underlying growth rate is essentially its long-term growth rate, which begins with the rate of growth in health care spending in recent decades and is projected to decline gradually—as people try to limit their spending for health care in order to maintain their consumption of other goods and services, and as state governments, private insurers, and employers respond to the pressures of rising health care costs.

On the basis of that formula, CBO expects that federal spending on the government's major health care programs will continue to rise substantially relative to GDP. The major health care programs are Medicare, Medicaid, the Children's Health Insurance Program (CHIP), and the subsidies for health insurance purchased through the exchanges.[6] In CBO's extended baseline, net federal spending for those programs grows from an estimated 5.2 percent of GDP in 2015 to 8.0 percent in 2040—of which 5.1 percentage points would be devoted to net spending on Medicare and 2.9 percentage points to spending on Medicaid, CHIP, and the exchange subsidies.

Those estimates are subject to considerable uncertainty (as Chapter 7 explains). A particular challenge currently is assessing how much of the recent slowdown in the growth of health care spending can be attributed to temporary factors, such as the recession, and how much reflects more enduring developments. Studies have generally concluded that part of the slowdown cannot be linked directly to the weak economy, although they differ considerably in their assessment of other factors' importance. CBO's own analysis found no direct link between the recession and slower growth in Medicare spending.[7] Accordingly, over the past several years, CBO has substantially reduced its 10-year and long-term projections of spending per person for Medicare, for Medicaid, and for the country as a whole. However, the growth rates for spending per person are expected to rebound somewhat from their recent very low levels without returning all the way to the high levels seen in the past.

Overview of Major Government Health Care Programs

A combination of private and public sources finances health care in the United States, mostly through various forms of health insurance. Most nonelderly Americans—

5. CBO followed that procedure for three of the four major health care programs but a different one for the Children's Health Insurance Program.

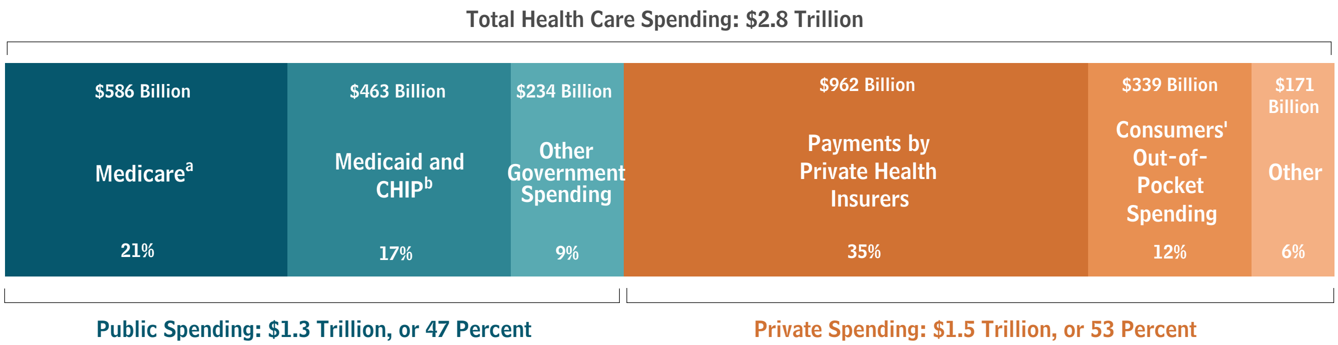
6. Federal spending on those programs is mandatory; that is, it results from budget authority provided in laws other than appropriation acts. Federal discretionary spending on health care—that is, spending that *is* subject to annual appropriations—is included not in the budget projections described here but rather in those for other noninterest spending (see Chapter 4 and Table 1-1 on page 20). Such discretionary spending includes spending for health research and for health care provided by the Veterans Health Administration. Some mandatory spending on health care (for example, spending for care for federal retirees) is also included in other noninterest spending; that mandatory spending represents a very small share of the federal budget. The spending for exchange subsidies that is analyzed in this chapter includes outlays for cost-sharing subsidies and for the refundable portion of subsidies for premiums; however, the reduction in taxes paid because of the premium subsidies—which is projected to be much smaller than the increase in outlays for the refundable portion of the subsidies—is included not here but in the revenue projections in Chapter 5.

7. Michael Levine and Melinda Buntin, *Why Has Growth in Spending for Fee-for-Service Medicare Slowed?* Working Paper 2013-06 (Congressional Budget Office, August 2013), www.cbo.gov/publication/44513.

Figure 2-1.

Distribution of Spending for Health Care, 2013

Total health care spending amounted to $2.8 trillion in calendar year 2013. That total does not include the cost to the federal government of the tax exclusion for employment-based health insurance, which amounted to roughly $250 billion in 2013.



Source: Congressional Budget Office based on data from the Centers for Medicare & Medicaid Services.

Note: CHIP = Children's Health Insurance Program.

a. Gross spending for Medicare refers to all of the program's spending not counting offsetting receipts (from premium payments made by beneficiaries to the government and amounts paid by states from savings on Medicaid's prescription drug costs) that are credited to the program.

b. Includes federal and state spending.

about 153 million of them in 2015, CBO and the staff of the Joint Committee on Taxation (JCT) estimate—have private health insurance obtained through an employer as their primary source of coverage. Many other people obtain insurance through government programs. In 2015, average monthly enrollment will be an estimated 55 million people in Medicare and an estimated 66 million in Medicaid.[8] In addition, CBO and JCT estimate that, over the course of this calendar year, an average of about 11 million nonelderly people will be covered by health insurance purchased through exchanges run by the federal government or state governments (though the total number enrolled at any particular time during the year might be higher), and most of those people will receive tax subsidies from the federal government to help pay for that insurance.[9] Another roughly 6 million people will be covered by a policy purchased directly from an insurer—that is, not through an exchange. At any given time during this calendar year, according to CBO and JCT's projections, about 35 million nonelderly people will be uninsured. Over the next few years, the number of people without insurance coverage is projected to decline.

In 2013, the most recent calendar year for which data are available, total spending for health care in the United States amounted to about $2.8 trillion (see Figure 2-1).[10] Of that amount, 53 percent was financed privately; specifically, 35 percent consisted of payments by private health insurers, 12 percent was consumers' out-of-pocket spending, and 6 percent came from other sources of

8. Congressional Budget Office, "Medicare—Baseline Projections" (March 2015), www.cbo.gov/publication/44205, and "Medicaid—Baseline Projections" (March 2015), www.cbo.gov/publication/44204. Both estimates given have been adjusted to reflect recently enacted legislation. Also, some people have coverage from more than one source at a time. Currently, about 8.3 million people with Medicaid coverage are also covered by Medicare, which is their primary source of coverage. For information about people eligible for benefits through both programs, see Congressional Budget Office, *Dual-Eligible Beneficiaries of Medicare and Medicaid: Characteristics, Health Care Spending, and Evolving Policies* (June 2013), www.cbo.gov/publication/44308.

9. Congressional Budget Office, "Effects of the Affordable Care Act on Health Insurance Coverage—Baseline Projections" (March 2015), www.cbo.gov/publication/43900. The estimates given have been adjusted to reflect recently enacted legislation.

10. This report defines total spending for health care as the health consumption expenditures in the national health expenditure accounts maintained by the Centers for Medicare & Medicaid Services. That definition excludes spending on medical research, structures, and equipment. Under a broader definition that includes those categories, total national spending for health care was 17.4 percent of GDP in calendar year 2013. For more information, see Micah Hartman and others, "National Health Spending in 2013: Growth Slows, Remains in Step With the Overall Economy," *Health Affairs*, vol. 34, no. 1 (January 2015), pp. 150–160, http://dx.doi.org/10.1377/hlthaff.2014.1107.

private funds, such as philanthropy.[11] The remaining 47 percent of total spending on health care was public: gross federal spending for Medicare, which made up 21 percent of the total; federal and state spending for Medicaid and CHIP, which accounted for 17 percent; and spending on various other programs (including those run by state and local governments' health departments, by the Department of Veterans Affairs, and by the Department of Defense), which accounted for 9 percent.

A significant share of private health care spending is subsidized through provisions in the tax code—primarily through the tax exclusion for employment-based health insurance, which is not reflected in the reported totals for health care spending. Under that provision, most payments that employers and employees make for health insurance coverage are exempt from payroll and income taxes. CBO estimates that in 2013, the federal cost, or tax expenditure, associated with that exclusion was roughly $250 billion, or 1.5 percent of GDP—a sum that was equal to nearly one-quarter of all spending on private health insurance and roughly equal to federal spending on Medicaid in that year.[12] It is projected to equal 1.6 percent of GDP over the 2016–2025 period.[13]

Medicare

In 2015, according to CBO's projections, Medicare will provide health insurance to about 55 million people who are elderly, are disabled, or have end-stage renal disease. The elderly make up about 85 percent of the enrollees; in general, people become eligible for Medicare when they reach 65, and disabled people become eligible 24 months after they qualify for benefits under Social Security's Disability Insurance program.[14]

The Medicare program provides a specified set of benefits. Hospital Insurance (HI), or Medicare Part A, covers inpatient services provided by hospitals, care in skilled nursing facilities, home health care, and hospice care. Part B mainly covers services provided by physicians, other practitioners, and hospitals' outpatient departments. Part D provides a prescription drug benefit. Most enrollees in Medicare are in the traditional fee-for-service program, in which the federal government pays for covered services directly; but about 30 percent have opted for Part C of the program, known as Medicare Advantage, in which they get coverage for Medicare benefits through a private health insurance plan. In 2014, gross spending for Medicare was $600 billion, and net spending (that is, gross spending minus offsetting receipts, which mostly consist of beneficiaries' payments of premiums) was $506 billion.

Parts A, B, and D of the program are financed in different ways. Outlays for Part A are financed by dedicated sources of income credited to a fund called the Hospital Insurance Trust Fund. Of those dedicated sources, the primary one is a payroll tax (amounting to 2.9 percent of all earnings), and the others are a 0.9 percent tax on earnings over $200,000 (or $250,000 for married couples) and a portion of the federal income taxes paid on Social Security benefits.[15] For Part B, premiums paid by beneficiaries cover just over one-quarter of outlays, and the government's general fund covers the rest. Enrollees' premiums under Part D are set to cover about one-quarter of the cost of the basic prescription drug benefit (although many low-income enrollees pay no premiums), and the general fund covers most of the rest. Federal payments to private insurance plans under Part C comprise a blend of funds drawn from Parts A, B, and D. Altogether, in calendar year 2013, about 43 percent of gross federal spending on Medicare was financed by the HI trust fund's

11. For the purposes of that analysis, out-of-pocket payments include payments made to satisfy cost-sharing requirements for services covered by insurance, as well as payments for services not covered by insurance. However, they do not include the premiums that people pay for health insurance—because premiums fund the payments that insurers provide, which have already been accounted for.

12. The estimated federal cost includes the effects on revenues from both payroll and income taxes. The income tax portion is based on Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2012–2017*, JCS-1-13 (February 1, 2013), http://go.usa.gov/3PkZA. For more information about the tax exclusion, see Congressional Budget Office, *The Distribution of Major Tax Expenditures in the Individual Income Tax System* (May 2013), www.cbo.gov/publication/43768.

13. Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), p. 103, www.cbo.gov/publication/49892.

14. People with amyotrophic lateral sclerosis (also known as Lou Gehrig's disease) are an exception: They are eligible for Medicare in the month when their Disability Insurance benefits start.

15. The thresholds for the 0.9 percent tax are not indexed for inflation. Certain people are subject to an additional 3.8 percent tax on unearned income that is officially labeled a Medicare tax even though the revenues are credited to the government's general fund rather than to the HI trust fund.

dedicated income, about 13 percent came from beneficiaries' premiums, and about 41 percent came from the general fund; money from other sources financed the rest.[16]

In the fee-for-service portion of Medicare, beneficiaries' cost-sharing obligations (that is, what they are obliged to pay out of pocket) vary widely by type of service, and the program does not set an annual limit on the health care costs for which beneficiaries are responsible. However, the great majority of beneficiaries—about 90 percent of them in 2010, according to one recent study—have supplemental insurance that covers many or all of the program's cost-sharing requirements.[17] The most common sources of supplemental coverage are plans for retirees offered by former employers, Medicare Advantage plans, individually purchased policies (called medigap insurance), and Medicaid.

A number of provisions of law constrain Medicare's payments to providers of health care. Most recently, the Medicare Access and CHIP Reauthorization Act of 2015 set the schedule of increases in Medicare's payment rates for physicians' services. Those increases will vary depending on the year and certain other factors, but they will range between zero and 0.75 percent per year.[18] That legislation also modified updates to payment rates for certain other services in some years.

The ACA also contains numerous provisions that, on balance, limit the growth of Medicare spending. The provisions that will have the greatest effect impose permanent reductions on the annual updates to payment rates for many providers (other than physicians) in the fee-for-service portion of the program. Under those provisions, the updates equal the estimated percentage change in the average prices of providers' inputs, such as labor and equipment, minus the 10-year moving average of growth in productivity in the economy overall. As a result, the providers will face pressure to match other businesses in their ability to use fewer inputs to produce a given amount of output. Other provisions of the ACA subtract specified fractions of a percentage point from the updates to payment rates for various services through 2019.

In addition, the ACA established the Independent Payment Advisory Board (IPAB), which is required to submit a proposal to reduce Medicare spending in certain years if the rate of growth in spending per enrollee is projected to exceed specified targets.[19] The proposal—or an alternative proposal submitted by the Secretary of Health and Human Services if the board does not submit a qualifying proposal—must achieve a specified amount of savings in the year it is implemented while not increasing spending in the succeeding nine years by more than the amount of those first-year savings. The proposal would go into effect automatically unless blocked or replaced by subsequent legislation. In CBO's baseline projections, the rate of growth of Medicare spending per beneficiary is below the target rate for each year through 2024 but exceeds it in 2025. As a result, CBO projects that the IPAB mechanism will reduce spending in 2025 by about $1 billion.[20]

Finally, the Budget Control Act of 2011, as amended, specifies automatic procedures known as sequestration (that is, the cancellation of funding) that will reduce most Medicare payments through September 2024 still further. Sequestration will reduce payment rates for most services

16. Those calculations are based on data from Boards of Trustees, Federal Hospital Insurance and Federal Supplementary Medical Insurance Trust Funds, *2014 Annual Report of the Boards of Trustees of the Federal Hospital Insurance and Federal Supplementary Medical Insurance Trust Funds* (July 2014), Table II.B1, http://go.usa.gov/bUZm. The measures of benefits and premium receipts in that table treat Part D premiums for basic benefits that beneficiaries pay directly to plans as if those premiums were paid to Medicare and then disbursed to the plans.

17. Medicare Payment Advisory Commission, *A Data Book: Health Care Spending and the Medicare Program* (June 2014), p. 27, http://go.usa.gov/3D3DQ (PDF, 1.7 MB).

18. From October 1998 through March 2015, payment rates for services covered by the fee schedule for physicians were governed by the sustainable growth rate (SGR) mechanism. In practice, however, the Congress almost always overrode the SGR mechanism when it was about to reduce payment rates. In April 2015, legislation was enacted that replaced that mechanism. For more details, see Congressional Budget Office, cost estimate for H.R. 2, the Medicare Access and CHIP Reauthorization Act of 2015 (March 2015), www.cbo.gov/publication/50053.

19. From 2015 through 2019, the target growth rate is the average of inflation in the economy generally and inflation for medical services in particular; in subsequent years, the target growth rate is the percentage increase in per capita GDP plus 1 percentage point. The ACA prohibits the IPAB from proposing certain actions, such as modifying Medicare's eligibility rules or reducing benefits.

20. Congressional Budget Office, "Medicare—Baseline Projections" (March 2015), Note f, www.cbo.gov/publication/44205. The estimate has since been updated to reflect recently enacted legislation, but it still stands at about $1 billion in 2025.

by 2.0 percent through the first half of fiscal year 2023, by 2.9 percent for the second half of 2023, by 1.1 percent for the first half of 2024, and by 4.0 percent for the second half of 2024, according to CBO's estimates. All told, CBO projects that sequestration will cancel about $150 billion of Medicare payments to providers and health insurance plans over the 2016–2025 period.

Medicaid

A joint federal-state program, Medicaid pays for health care services, mostly for low-income people. About 83 million people will be enrolled in Medicaid at some point during 2015, CBO estimates, and the average monthly enrollment will be about 66 million.[21] Currently, almost half of Medicaid's enrollees are children in low-income families; almost one-third are adults under age 65 who are not disabled; and the remaining one-fifth or so are elderly or disabled adults. Expenses tend to be much higher for beneficiaries who are elderly or disabled, many of whom require long-term care, than for other beneficiaries. In 2014, about 30 percent of federal spending for benefits was for long-term services and supports, a category that includes institutional care provided in nursing homes and certain other facilities, as well as care provided in a person's home or in the community. In that year, the elderly or disabled accounted for more than half of federal spending for Medicaid benefits.[22]

States administer their Medicaid programs under federal guidelines that mandate a minimum set of services that must be provided to certain categories of low-income people. The required services include inpatient and outpatient hospital services, services provided by physicians and laboratories, comprehensive and preventive health care services for children, nursing home and home health care, and transportation. The required eligibility categories include families that would have met the financial requirements of the Aid to Families With Dependent Children program when it existed; elderly and disabled people who qualify for the Supplemental Security Income program; and children and pregnant women in families with income below 138 percent of the federal poverty guidelines (commonly referred to as the federal poverty level or FPL).[23]

Nevertheless, beyond the federal requirements, state governments have substantial flexibility to determine eligibility, benefits, and payments to providers under Medicaid. States may choose to make additional groups of people eligible (such as elderly adults who have income above the usual eligibility thresholds but who have high medical expenses relative to their income) or to provide additional benefits (such as coverage for prescription drugs and dental services). Moreover, many states seek and receive federal waivers that allow them to provide benefits and cover groups that would otherwise be excluded. Most recently, as a result of the ACA and a subsequent Supreme Court ruling, each state has the option to expand eligibility for Medicaid to most nonelderly adults with income below 138 percent of the FPL.[24] Currently, 29 states and the District of Columbia, which together contain about half of the people who meet the new eligibility criteria, have expanded their programs. CBO anticipates that more states will expand coverage during the next few years and that, by 2020, about 80 percent of the people who meet the new eligibility criteria will be in states that have expanded coverage.

The federal government's share of Medicaid's spending for benefits varies by state and has historically averaged about 57 percent. However, for enrollees newly eligible under the ACA's coverage expansion, the federal government will pay all costs through 2016, a slightly declining share of costs from 2017 to 2019, and 90 percent of costs in 2020 and beyond. According to CBO's estimates, those changes will raise the federal share of Medicaid

21. Those two estimates differ from each other for two reasons. First, many people are enrolled in Medicaid for less than 12 months. Second, for most enrollees, the typical 12-month eligibility period straddles two consecutive years. That is, some enrollees leave Medicaid partway through the year, after their eligibility period ends; other enrollees begin a new eligibility period after the start of the year. As a result, the total number of people enrolled in Medicaid at some point in the year is significantly higher than the average number of people enrolled in a given month.

22. Congressional Budget Office, "Medicaid—Baseline Projections" (March 2015), www.cbo.gov/publication/44204.

23. The FPL is currently $24,250 for a family of four. See Department of Health and Human Services, Office of the Assistant Secretary for Planning and Evaluation, "2015 Poverty Guidelines" (January 2015), http://aspe.hhs.gov/poverty/15poverty.cfm.

24. In fact, the ACA expanded eligibility for Medicaid to include nonelderly residents with income of up to 133 percent of the FPL, but the act defined income in a way that effectively raised that threshold to 138 percent of the FPL. As a result of the Supreme Court decision, which was issued on June 28, 2012 (*National Federation of Independent Business v. Sebelius*, 132 S. Ct. 2566 (2012)), some states chose not to expand their programs.

spending to between 62 percent and 64 percent in 2015 and later years.[25]

In 2014, federal spending for Medicaid amounted to $301 billion, of which $270 billion covered benefits for enrollees. (The rest included payments to hospitals that served a disproportionate share of Medicaid patients and low-income uninsured patients, costs for the Vaccines for Children program, and administrative expenses.) On the basis of data provided by the Centers for Medicare & Medicaid Services (CMS), CBO estimates that the states spent $195 billion on Medicaid in that year.[26]

Children's Health Insurance Program

CHIP, a much smaller joint federal-state program, provides health insurance coverage for children in families whose income, though modest, is too high for them to qualify for Medicaid.[27] States have discretion to determine income eligibility, but it usually falls in the range between 100 percent and 300 percent of the FPL. Like Medicaid, CHIP is administered by the states within broad federal guidelines. Unlike Medicaid, however, CHIP has a fixed nationwide limit on federal spending.[28]

In 2014, federal spending on CHIP was $9.3 billion, and about 8 million people (almost all of them children) were enrolled in the program at some point during the year.[29] The federal share of CHIP spending varies among the states but usually averages about 70 percent.[30]

25. Congressional Budget Office, "Medicaid—Baseline Projections" (March 2015), Note a, www.cbo.gov/publication/44204.

26. CBO's calculations rely on unpublished data from states' filings of the CMS-64 Quarterly Expense Report for fiscal year 2014. States use that form to report their spending for Medicaid-covered benefits and administrative activities.

27. Under certain conditions, pregnant women and parents of children enrolled in CHIP are also eligible for the program, but they constitute a very small percentage of the program's enrollment. See Congressional Budget Office, "Children's Health Insurance Program—Baseline Projections" (March 2015), www.cbo.gov/publication/44189.

28. CHIP also differs from Medicaid in that its funding expires after September 2017, under current law.

29. Congressional Budget Office, "Children's Health Insurance Program—Baseline Projections" (March 2015), www.cbo.gov/publication/44189.

Subsidies for Insurance Purchased Through Exchanges

Many people can buy subsidized insurance through exchanges (also called marketplaces) operated by the federal government, by state governments, or through a partnership between federal and state governments. There are two kinds of subsidy: refundable tax credits to help pay for premiums; and cost-sharing subsidies to reduce out-of-pocket expenses, such as deductibles and copayments. To qualify for the premium tax credits, a person generally must have household income between 100 percent and 400 percent of the FPL and must not have access to certain other sources of health insurance coverage. (The most common examples are coverage through an employer that meets the law's definition of being affordable and coverage from a government program, such as Medicare or Medicaid.) To qualify for the cost-sharing subsidies, a person must meet the requirements for the premium tax credits, enroll in what the ACA calls a silver plan (which covers about 70 percent of the cost of covered benefits), and have household income below 250 percent of the FPL.

The size of a person's premium tax credit is the difference between the cost of the second-lowest-cost silver plan available to that person and a specified percentage of his or her household income. For example, in calendar year 2014, the tax credit was set so that people with income between 100 percent and 133 percent of the FPL would pay about 2 percent of their income to enroll in the second-lowest-cost silver plan, while people with higher income would pay a larger share of their income, up to about 9.5 percent for those with income between 300 percent and 400 percent of the FPL. (Therefore, if a person's premium for such a plan would be less than the applicable percentage of income, that person would receive no tax credit.) The amounts that enrollees must pay are indexed so that the subsidies cover roughly the same shares of the premiums over time. After calendar year 2017, however, an additional indexing factor may apply; if so, the shares of the premiums that enrollees pay

30. The ACA provided for a 23 percentage-point increase in the federal share of each state's CHIP spending from 2016 through 2019. CBO estimates that the average federal share will consequently rise from 70 percent to 93 percent during those four years before reverting to 70 percent in 2020. See Centers for Medicare & Medicaid Services, "Children's Health Insurance Program Financing" (accessed April 6, 2015), http://tinyurl.com/kqjfj3s.

will increase, and the shares of the premiums that the subsidies cover will decline.[31]

CBO and JCT estimate that, over the course of calendar year 2015, an average of about 11 million people will be covered by insurance purchased through the exchanges, of whom about 8 million will receive subsidies and 3 million will not. Over time, coverage through the exchanges will increase substantially, CBO and JCT expect, as people respond to the subsidies and to rising penalties for failing to obtain coverage. According to CBO and JCT's projections, an average of about 21 million people will have such coverage in 2016, and between 22 million and 24 million will have it in each year between 2017 and 2025. Roughly three-quarters of those enrollees are expected to receive subsidies. In fiscal year 2015, outlays for those subsidies and related spending will be about $41 billion, CBO and JCT estimate.[32]

The Historical Growth of Health Care Spending

Total spending for health care in the United States—that is, private and public spending combined—has risen significantly as a share of GDP over the past several decades. Such spending has grown relative to GDP in most years, except for the periods between calendar years 1993 and 2000 and again between 2009 and 2013 (the most recent year for which data are available). During both of those periods, spending for health care remained roughly stable as a share of the economy.

Some analysts have attributed the lull in growth from 1993 to 2000 to a substantial rise in the number of people enrolled in managed care plans and to excess capacity among providers of some types, which increased the leverage that health plans had in negotiating payments to providers; also, economic growth was relatively rapid in that period, making it easier for rising spending to remain stable as a share of the economy.[33] In examining the more recent slowdown in health care spending—from 2009 to 2013—analysts have reached different conclusions about the relative contributions of the weak economy and of changes in the delivery and financing of health care. Some analysts believe that an expansion of high-deductible health plans, increasing efforts by states to control Medicaid spending, and a slackening in the diffusion of new technologies are the key factors in the most recent slowdown.[34] Others believe that the weakened economy has been the primary factor.[35] How long the slowdown may persist is highly uncertain. In fact, one recent study estimated that total spending for health care in the United States increased as a share of GDP in calendar year 2014 and would continue to do so through 2023 (the last year included in the analysis).[36]

Spending for Medicare and Medicaid has also grown quickly in the past few decades, partly because of rising enrollment and partly because of rising costs per enrollee. Between 1985 and 2014, net federal spending for Medicare rose from 1.5 percent of GDP to 2.9 percent, and federal spending for Medicaid rose from 0.5 percent of GDP to 1.7 percent. (*Total* spending for Medicaid, including spending by the states, rose from 0.9 percent of GDP to 2.9 percent.) During the last few years of that period, however, net federal spending for Medicare grew

31. The additional indexing factor will apply in any year after calendar year 2017 in which the total costs of the exchange subsidies exceed a specified percentage of GDP. CBO expects that the indexing factor will apply in some years, although the uncertainty of projections of both the exchange subsidies and GDP make the timing unclear. For an explanation of the indexing factor, see Congressional Budget Office, *Additional Information About CBO's Baseline Projections of Federal Subsidies for Health Insurance Provided Through Exchanges* (May 2011), www.cbo.gov/publication/41464.

32. Congressional Budget Office, "Effects of the Affordable Care Act on Health Insurance Coverage—Baseline Projections" (March 2015), Table 3, www.cbo.gov/publication/43900. Related spending includes grants to states and payments by the federal government to insurers under several provisions of the ACA.

33. See Katharine Levit and others, "National Health Expenditures in 1997: More Slow Growth," *Health Affairs,* vol. 17, no. 6 (November/December 1998), pp. 99–110, http://dx.doi.org/10.1377/hlthaff.17.6.99.

34. See, for example, Amitabh Chandra, Jonathan Holmes, and Jonathan Skinner, "Is This Time Different? The Slowdown in Health Care Spending," *Brookings Papers on Economic Activity* (Fall 2013), pp. 261–323, http://tinyurl.com/pyrjret (PDF, 752 KB).

35. See, for example, Larry Levitt and others, *Assessing the Effects of the Economy on the Recent Slowdown in Health Spending* (Kaiser Family Foundation, April 2013), http://tinyurl.com/m78guc9; and David Dranove and others, "Health Spending Slowdown Is Mostly Due to Economic Factors, Not Structural Change in the Health Care Sector," *Health Affairs*, vol. 33, no. 8 (August 2014), pp. 1399–1406, http://dx.doi.org/10.1377/hlthaff.2013.1416.

36. Andrea M. Sisko and others, "National Health Expenditure Projections, 2013–23: Faster Growth Expected With Expanded Coverage and Improving Economy," *Health Affairs*, vol. 33, no. 10 (October 2014), pp. 1841–1850, http://dx.doi.org/10.1377/hlthaff.2014.0560.

only about as quickly as the overall economy did. Federal spending for Medicaid also grew at about that rate in recent years—until 2014, when spending for Medicaid increased rapidly because of the expansion of Medicaid coverage under the ACA. Between 2013 and 2014, net Medicare spending grew by only 2.8 percent, whereas federal Medicaid spending grew by 13.6 percent.[37]

Factors Affecting the Growth of Health Care Spending

A crucial factor underlying the rise in per capita spending for health care during the past few decades has been the emergence, adoption, and widespread diffusion of new medical technologies and services.[38] Major advances in medical science allow providers to diagnose and treat illnesses in ways that previously were impossible. Many of those innovations rely on costly new drugs, equipment, and skills.[39] Other innovations are relatively inexpensive, but their costs add up quickly as growing numbers of providers and patients make use of them. Although technological advances can sometimes reduce costs, they have generally increased total health care spending.

Other factors that have contributed to the growth of per capita spending on health care in recent decades include increases in personal income and changes in insurance coverage—in particular, declines in the share of health care costs that people with coverage pay out of pocket. Demand for medical care tends to rise as real (that is, inflation-adjusted) family income increases. People also use more care if they pay a smaller portion of the cost—and between 1970 and 2000, the share of total health care spending paid out of pocket declined rapidly, from 37 percent to 16 percent.[40] (More recently, the rate of decline has slowed, leaving the share of health care spending paid out of pocket at about 12 percent in 2013; reasons for that slowing include an increase in the share of insured people who have an annual deductible and an increase in the share enrolled in high-deductible health plans.)

In general, disentangling the effects of technology, income, and insurance coverage on the growth of health care spending is difficult, because rising income and expanding insurance coverage have themselves increased the demand for new technologies. One study estimated that new medical technologies and rising income were the most important factors behind the growth of health care spending between 1960 and 2007, and that the two accounted for roughly equal shares of that growth—but also that the effect of increasing insurance coverage during that period was highly uncertain.[41] Another study concluded that after Medicare was introduced, the resulting expansion of insurance coverage increased health care spending not just for the elderly patients who gained coverage but for younger patients as well. Part of the reason, according to the study, was that the increased insurance coverage spurred a more rapid and widespread adoption of existing treatment methods, such as those provided by cardiac intensive care units, for the elderly and nonelderly alike—though the study concluded that questions remained about the magnitude of those effects.[42]

Spending on health care per person would also be expected to grow if people were developing more health problems or becoming more likely to contract diseases, but the evidence about the importance of those factors is mixed. In particular, researchers have reached different

37. Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), p. 11, www.cbo.gov/publication/49892.

38. Congressional Budget Office, *Technological Change and the Growth of Health Care Spending* (January 2008), www.cbo.gov/publication/41665.

39. See, for example, Jay H. Hoofnagle and Averell H. Sherker, "Therapy for Hepatitis C—The Costs of Success," *The New England Journal of Medicine*, vol. 370, no. 16 (April 17, 2014), pp. 1552–1553, http://tinyurl.com/p7z4tyu.

40. Centers for Medicare & Medicaid Services, National Health Expenditure Accounts, "NHE Tables" (accessed April 3, 2015), http://go.usa.gov/jmGY.

41. Sheila Smith, Joseph P. Newhouse, and Mark S. Freeland, "Income, Insurance, and Technology: Why Does Health Spending Outpace Economic Growth?" *Health Affairs*, vol. 28, no. 5 (September/October 2009), pp. 1276–1284, http://dx.doi.org/10.1377/hlthaff.28.5.1276.

42. Amy Finkelstein, "The Aggregate Effects of Health Insurance: Evidence From the Introduction of Medicare," *The Quarterly Journal of Economics*, vol. 122, no. 1 (February 2007), pp. 1–37, http://tinyurl.com/oqlrvjq. One factor that may have contributed to that study's findings was the relatively generous payment system that Medicare adopted. Following the common practice of private insurers at the time, Medicare initially paid hospitals on the basis of their incurred costs—an approach that gave hospitals little incentive to control those costs—rather than according to fee schedules, as it does today. The increase in hospital spending that resulted from Medicare's creation might have been smaller under a less generous payment system.

Table 2-1.

Average Annual Rate of Excess Cost Growth in Spending for Health Care

Percent

	Medicare	Medicaid	Other	Overall
1975 to 2013	1.9	1.5	1.8	1.8
1980 to 2013	1.6	1.2	1.7	1.6
1985 to 2013	1.4	0.9	1.5	1.4
1990 to 2013	1.2	0.3	1.3	1.1

Source: Congressional Budget Office.

Note: Excess cost growth refers to the extent to which the growth rate of nominal health care spending per capita—adjusted for demographic characteristics of the relevant populations—outpaces the annual growth rate of potential gross domestic product (GDP) per capita, on average. (Potential GDP is CBO's estimate of the maximum sustainable output of the economy.) The historical rates of excess cost growth are a weighted average of annual rates: Twice as much weight is placed on the latest year as on the earliest year.

conclusions about the extent to which spending growth is affected by changes in the prevalence of chronic diseases (such as cardiovascular disease, diabetes, and arthritis); in the share of the people with those diseases who receive treatment; and in the costs per case of treating those diseases.[43]

Studies that have analyzed the growth of health care spending have consistently found that the aging of the population has had only a small effect on it.[44] Although older adults have higher average medical expenses than younger adults do, the age composition of the population has not changed enough to account for much of the increase in per capita spending. Aging has had a larger effect on *federal* spending for health care, however, because nearly all U.S. residents become eligible for Medicare when they turn 65. From 1985 to 2015, the share of the population that was at least 65 years old grew by about one-quarter, from almost 12 percent to 15 percent.

Excess Cost Growth

As part of its analysis of health care spending, CBO calculates the growth in that spending per person relative to the growth of potential GDP per person after removing the effects of demographic changes on health care spending—in particular, changes in the age distribution of the population.[45] The resulting ratio is called excess cost growth. The phrase is not intended to imply that growth in per capita spending for health care is necessarily excessive or undesirable; excess cost growth simply measures the extent to which the growth in such spending (adjusted for demographic changes) outpaces the growth in potential output per capita.

According to CBO's calculations, average rates of excess cost growth have ranged between 0.3 percent and 1.9 percent for various parts of the health care system and during various periods in the past several decades (see Table 2-1).[46] Although such rates are quite variable from year to year, they have generally declined over the past few decades, probably because of two important shifts in how care is financed. First, private health insurance has moved away from indemnity policies—which generally

43. For additional discussion, see Congressional Budget Office, *Key Issues in Analyzing Major Health Insurance Proposals* (December 2008), p. 23, www.cbo.gov/publication/41746. See also Congressional Budget Office, *How Does Obesity in Adults Affect Spending on Health Care?* (September 2010), www.cbo.gov/publication/21772; Charles S. Roehrig and David M. Rousseau, "The Growth in Cost per Case Explains Far More of U.S. Health Spending Increases Than Rising Disease Prevalence," *Health Affairs*, vol. 30, no. 9 (September 2011), pp. 1657–1663, http://dx.doi.org/10.1377/hlthaff.2010.0644; and Kenneth E. Thorpe and others, "The Rising Prevalence of Treated Disease: Effects on Private Health Insurance Spending," *Health Affairs*, web exclusive (June 2005), http://dx.doi.org/10.1377/hlthaff.w5.317.

44. See, for example, Uwe E. Reinhardt, "Does the Aging of the Population Really Drive the Demand for Health Care?" *Health Affairs*, vol. 22, no. 6 (November 2003), pp. 27–39, http://dx.doi.org/10.1377/hlthaff.22.6.27.

45. Potential GDP is CBO's estimate of the maximum sustainable output of the economy; using potential GDP rather than actual GDP in the calculation of excess cost growth limits the effect of cyclical changes in the economy on that calculation.

46. The rates of excess cost growth are a weighted average of annual rates in which twice as much weight was placed on the latest year as on the earliest year. In calculating excess cost growth for Medicare, CBO adjusted for changes in the age distribution of beneficiaries. In calculating excess cost growth for Medicaid, CBO adjusted for changes in the program's case mix—that is, the proportions of beneficiaries who were children, elderly, disabled, and none of the above—rather than for changes in the age distribution of beneficiaries. The rates of excess cost growth adjusted for demographic changes reflect changes in spending per person rather than changes in the number or composition of beneficiaries. The introduction of Medicare's Part D drug benefit in 2006 resulted in a onetime shift in some spending from Medicaid to Medicare; to adjust for that shift, CBO assumed that excess cost growth in 2006 for both Medicare and Medicaid was equal to the average of excess cost growth in the two programs for that year.

reimburse enrollees for their incurred medical costs and which predominated before the 1990s—and toward greater management of care. Second, beginning in the 1980s, Medicare shifted from payments that were based on the costs that providers incurred or the charges that they submitted to fee schedules that constrained price increases.

Excess cost growth has been especially low, on average, during two periods—in most of the 1990s and during the past few years. In the mid- to late 1990s, managed care was spreading rapidly, and some of the low excess cost growth probably represented a series of onetime downward shifts in health care costs, spread out over several years, rather than a permanent change in the underlying growth rate of health care spending. During the past few years, some of the low excess cost growth has probably reflected the economic downturn and may be reversed once the economy recovers further. Even the part of the currently low excess cost growth that reflects structural changes in how care is delivered or how it is financed may largely represent another onetime downward shift in costs, rather than a permanent reduction in the growth rate of spending.

For those reasons, even though growth rates are currently below the historical average, CBO judges that the rate of excess cost growth in overall spending on health care since 1985 is the rate that best reflects features of the health care delivery and financing systems that are likely to endure for a number of years—which is important because the agency uses its estimate of historical excess cost growth to inform its projections of future spending. Within that period, the later years provide a more useful guide to the future than the earlier years do. Therefore, CBO calculated a weighted average of the annual excess cost growth rates between 1985 and 2013 (the latest year for which data are available), placing twice as much weight on the latest year as on the earliest year and setting the weights for intermediate years by following a linear progression between the two. After making that adjustment, CBO arrived at its estimate of the historical rate of excess cost growth to be used as a basis for its long-term projections: 1.4 percent per year.[47]

Long-Term Responses to Rising Health Care Costs

Health care spending cannot rise more quickly than GDP forever. When that spending increases as a share of GDP, it absorbs a growing share of people's income, restraining the consumption of other goods and services and building pressure to slow its growth, both in the private sector and in government programs. Those responses will occur even if, as CBO assumes in making its projections, current federal law does not change.

Responses in the Private Sector, Health Insurance Exchanges, and Medicaid

CBO expects that the private sector will respond to rising health care costs by pursuing various ways to restrain spending. Many employers will intensify their efforts to reduce the costs of the insurance plans that they offer—for example, by working with insurers and providers to make the delivery of health care more efficient, by limiting the amount of insurance coverage that they offer, or by offering a fixed contribution that employees can use to purchase health insurance. Some employees will move to plans with more tightly managed benefits, narrower networks of providers, or higher cost-sharing requirements—moves that would lower premiums by shifting costs to the employees, but that also could reduce total spending on health care. Such changes are already under way; for example, the share of covered workers with an annual deductible increased from 55 percent in 2006 to 80 percent in 2014.[48]

When it goes into effect in 2018, an excise tax on certain health insurance plans with high premiums will also encourage some employers and individuals to choose plans with lower premiums. In some cases, employers are already reducing the benefits that their insurance plans cover or increasing workers' deductibles and copayments to avoid having to pay the tax in the future.[49] Although the excise tax will not apply to health insurance plans offered through exchanges, people buying coverage through exchanges are also likely to seek ways to avoid

47. The same method applied to data through 2007 yields an estimate of 1.6 percent per year. That is, the slow growth of health care spending experienced during the past several years, all else being equal, has reduced the average rate of excess cost growth by about 0.2 percentage points.

48. Gary Claxton and others, *Employer Health Benefits: 2014 Annual Survey* (Kaiser Family Foundation and Health Research and Educational Trust, September 2014), p. 120, http://tinyurl.com/q7h4osw.

49. Julie Piotrowski, "Excise Tax on 'Cadillac' Plans," Health Policy Briefs, *Health Affairs* (September 12, 2013), http://tinyurl.com/my4kfd7.

higher premiums, which will tend to slow the growth of federal spending for the exchange subsidies.[50]

Many state governments will respond to growing costs for Medicaid by restraining payment rates to providers and managed care plans, limiting the services that they choose to cover, or tightening eligibility for the program so that it serves fewer beneficiaries than it would have otherwise. Because federal spending for Medicaid depends on state spending, such actions by the states will tend to slow the growth of federal spending for the program as well.

Over the long term, those responses by businesses, individuals, and state governments will sharply slow the growth of health care spending, resulting in a reduction of the rate of excess cost growth in the health care system, CBO projects. That slowdown could occur in different ways. Improvements in the efficiency of the health care sector, for example, could lower the rate of excess cost growth. Many experts believe that a substantial share of current health care spending is of low value, meaning that the services provided yield little health benefit relative to their costs. If the use of such services fell, the rate of excess cost growth could also decline for an extended period without imposing direct costs on patients. However, reducing the use of low-value care without affecting high-value care is very challenging, so the degree to which such a reduction might occur is highly uncertain.[51]

The responses to high and rising health care costs could have other effects as well. They could lead to significant changes in the amount that people paid directly for care, their access to care, or the quality of care—at least, relative to what would have occurred without a slowdown in spending. In the private sector, people might face increased cost-sharing requirements and narrower networks of providers; new and potentially useful health technologies might be introduced more slowly or used less frequently than they would have been otherwise; and more treatments and interventions might not be covered by insurance. Those outcomes might affect people with employment-based health insurance and people purchasing health insurance through the exchanges. In Medicaid, some beneficiaries might lose their eligibility or have to pay more out of pocket if states narrowed their eligibility criteria or dropped coverage of optional services. Medicaid beneficiaries might also end up with more tightly managed care. In addition, private insurers and Medicaid programs might constrain payments to providers in ways that limited access to care, the quality of care, or both.

Responses in Medicare

Many features of the Medicare program cannot be altered without changes in federal law. Still, a reduction in spending growth elsewhere in the health care sector would probably affect Medicare, which is integrated to a significant degree with the other parts of the health care system. In particular, spending on Medicare will slow to the extent that actions by businesses, individuals, and states result in lower-cost patterns of practice by physicians, slower development and diffusion of new medical technologies, and cost-limiting changes to the structure of the overall health care system.

In addition, current law includes a number of incentives and mechanisms that could reduce spending growth in Medicare. For one thing, the program's premiums and cost sharing will consume a growing share of beneficiaries' income—because the growth of health care spending in general is projected to outpace the growth of income—and that will constrain demand for some Medicare services. Changes being made in the structure of Medicare's payments to providers, such as financial incentives to reduce hospital-acquired infections and readmissions, may also help hold down federal spending.[52] Further, the Center for Medicare & Medicaid Innovation, an arm of CMS, is testing promising ways to modify rules and payment methods that could reduce costs without impairing

50. A recent analysis of insurance plans available through exchanges found that many consumers continued enrolling in cheaper plans with narrower networks of providers even though they reported low satisfaction with those plans. See McKinsey Center for U.S. Health System Reform, *Hospital Networks: Evolution of the Configurations on the 2015 Exchanges* (April 2015), http://tinyurl.com/pnyv563 (PDF, 881 KB).

51. See Katherine Baicker, Sendhil Mullainathan, and Joshua Schwartzstein, *Behavioral Hazard in Health Insurance*, Working Paper 18468 (National Bureau of Economic Research, October 2012), www.nber.org/papers/w18468.

52. Sarah L. Krein and others, "Preventing Hospital-Acquired Infections: A National Survey of Practices Reported by U.S. Hospitals in 2005 and 2009," *Journal of General Internal Medicine*, vol. 27, no. 7 (July 2012), pp. 773–779, www.ncbi.nlm.nih.gov/pmc/articles/PMC3378739/. For a description of the program to reduce hospital readmissions, see Centers for Medicare & Medicaid Services, "Readmissions Reduction Program" (accessed April 6, 2015), http://go.usa.gov/DxKC.

the quality of health care; the changes that prove effective may be expanded by the Secretary of Health and Human Services.[53] Several such demonstrations are currently under way, but which, if any, will prove successful in slowing spending growth for Medicare as a whole is uncertain.

Growth in Medicare spending will also be constrained by the rules governing the annual updates that are made to Medicare's payment rates for health care services. The scheduled updates will generally be smaller than the increases in the prices of inputs (namely, labor and supplies) used to deliver care. But it is unclear whether providers' responses to that constraint will lead to offsetting increases or to further reductions in spending for Medicare and other health care programs. The answer depends on whether or to what extent the providers can restrain the growth of their costs, either by increasing their productivity over time—that is, producing the same quantity and quality of output (treatments and procedures) with fewer or less costly inputs—or by other means.

There is considerable uncertainty, partly because of data limitations, about the degree of productivity growth in the health care sector and how it compares with productivity growth in the economy as a whole. Some evidence suggests that productivity growth in the hospital industry is substantial. For example, one recent study found such evidence for selected medical conditions, after adjusting for trends in the severity of illness and improvements in patients' outcomes.[54] Also, a recent analysis by CMS indicates that Medicare's payment updates for services by providers other than physicians were, on average, roughly in line with general price inflation (which reflects growth in productivity in the economy as a whole) over the 1991–2011 period.[55] Furthermore, an analysis by the American Hospital Association indicates that private-sector payment rates grew at about the same pace as Medicare's payment rates over that period, on average, and that aggregate profit margins for hospitals in 2012 were higher than those in the early 1990s.[56] Taken together, those findings suggest that, on average, hospitals have improved their productivity roughly in line with economywide productivity growth.[57] Earlier evidence, however, suggests that productivity growth in the hospital industry is very low.[58] Evidence about productivity growth for physicians is harder to interpret, partly because of the challenges involved in measuring the quality of the care that they provide.[59]

If providers cannot increase their productivity enough over time to keep the growth of their costs in line with the updates to Medicare's payment rates, they might respond in other ways, such as reducing the quality of care, reducing Medicare beneficiaries' access to care (which might reduce spending), or trying to increase revenues by other means (which might increase spending). Providers that are not able to adjust to the constraint imposed by the payment updates might merge with more profitable providers or close.

If access to providers under the traditional fee-for-service program declined, more enrollees might shift into Medicare Advantage plans, which are not bound by the updates to payment rates that apply to traditional Medicare. Medicare Advantage plans might be able to offer better access to care than the fee-for-service program if they increased the rates that they paid providers, but that would probably require enrollees in such plans to pay higher premiums. Because federal payments to those plans are based largely on costs in the fee-for-service

53. A list of the center's ongoing projects is available at Centers for Medicare & Medicaid Services, "Innovation Models" (accessed April 6, 2015), http://go.usa.gov/3Dc2Q.

54. John A. Romley, Dana P. Goldman, and Neeraj Sood, "U.S. Hospitals Experienced Substantial Productivity Growth During 2002–11," *Health Affairs*, vol. 34, no. 3 (March 2015), pp. 511–518, http://dx.doi.org/10.1377/hlthaff.2014.0587.

55. Centers for Medicare & Medicaid Services, *Review of Assumptions and Methods of the Medicare Trustees' Financial Projections* (December 2012), p. 60, http://go.usa.gov/Xn7Q.

56. American Hospital Association, "Trends in Hospital Financing," in *Trends Affecting Hospitals and Health Systems* (accessed April 6, 2015), http://tinyurl.com/m4by9zd.

57. Less information is readily available about the influence of changes in Medicare's payment rates and methods over the past two decades on the growth of costs for other providers.

58. Jonathan D. Cylus and Bridget A. Dickensheets, "Hospital Multifactor Productivity: A Presentation and Analysis of Two Methodologies," *Health Care Financing Review*, vol. 29, no. 2 (Winter 2007–2008), pp. 49–64, http://go.usa.gov/XrHC; and Michael J. Harper and others, "Nonmanufacturing Industry Contributions to Multifactor Productivity, 1987–2006," *Monthly Labor Review*, vol. 133, no. 6 (June 2010), pp. 16–31, www.bls.gov/opub/mlr/2010/06/art2full.pdf (1 MB).

59. See Joseph P. Newhouse and Anna D. Sinaiko, "Estimates of Physician Productivity: An Evaluation," *Health Care Financing Review*, vol. 29, no. 2 (Winter 2007–2008), pp. 33–39, www.ncbi.nlm.nih.gov/pmc/articles/PMC4195017/.

program, it is unclear whether such a shift—if it were to occur—would substantially alter the trajectory of Medicare spending.

Because of the uncertainty about the responses of Medicare providers to the payment updates, CBO has not adjusted its projections of spending in the long term to take such responses into account.

CBO's Method for Making Long-Term Projections of Federal Health Care Spending

CBO's extended baseline projections of federal spending on the major health care programs, like the rest of the agency's extended baseline projections, generally reflect the provisions of current law. The projections in the extended baseline for the next 10 years match the agency's 10-year baseline projections as adjusted to reflect recently enacted legislation, which are based on detailed analysis of the major health care programs. Beyond the coming decade, however, projecting federal health care spending becomes increasingly difficult because of the considerable uncertainties involved. A wide range of changes could occur—in people's health, in the sources and extent of their insurance coverage, and in the delivery of medical care—that are almost impossible to predict but that could have a significant effect on federal health care spending.

Therefore, for the projections beyond 2025, CBO has adopted a formulaic approach—one that combines estimates of the number of beneficiaries of government health care programs with fairly mechanical projections of spending growth per beneficiary. CBO has estimated spending growth per beneficiary by combining projected growth in potential GDP per capita and projected excess cost growth for the program in question (with adjustments for demographic changes in the beneficiaries of that program).

The long-term projections of excess cost growth depend on CBO's assessment of the *underlying* rates of excess cost growth. The underlying growth rates begin in 2014 with the historical average rate of excess cost growth described above—1.4 percent per year—and are projected to decline gradually, at different rates for different programs, in response to the pressures created by rising costs. Projected excess cost growth for each program depends on the rate of excess cost growth for that program implied by the baseline projections for the next decade; on CBO's assessment of the underlying rate of excess cost growth for the program a quarter century from now and beyond; and on a blend of those factors for the intervening period (the 11th through the 24th years of the projection).

Excess Cost Growth Over the Next Decade

For 2016 through 2025, the projected rates of excess cost growth used in CBO's extended baseline are derived from CBO's 10-year baseline:

- For Medicare, CBO's baseline projections imply an average annual rate of excess cost growth over that decade of about 0.4 percent; that is, spending per beneficiary for Medicare (adjusted for demographic changes) is projected to grow slightly faster than potential GDP per capita. That slow projected growth rate stems partly from slow projected growth in the use of Medicare services, which is consistent with recent experience. In addition, some of the limitations on payments under current law will be phased in. Consequently, excess cost growth in Medicare is projected to be negative during the next few years and then to rise to about 0.8 percent per year by the end of the decade.

- For federal Medicaid spending, CBO's baseline projections imply an average annual rate of excess cost growth of 0.5 percent (after the effects of the changing federal share of Medicaid spending are removed). The expansion of benefits in some states to people with income of up to 138 percent of the FPL will increase total Medicaid spending; it will also probably change the average cost per enrollee over the next several years, because average spending on the new enrollees (mostly adults who are not disabled) will tend to differ from average spending on previously eligible enrollees. However, excess cost growth incorporates an adjustment for demographic changes, so it is not significantly affected by the expansion.

- For the exchange subsidies, CBO's baseline projections of spending per enrollee depend on its projections of private health insurance premiums. The agency's baseline projections imply an average annual rate of excess cost growth of about 2 percent for those premiums. The agency's projections of spending per enrollee on the exchange subsidies also account for the likelihood that federal subsidies will cover a declining share of the premiums over time as a result of the additional indexing factor mentioned above.

Underlying Rates of Excess Cost Growth

CBO's projections of the underlying rates of excess cost growth are calculated as follows:

- For all parts of the health care system, the underlying rate of excess cost growth in 2014 equals the weighted average rate of excess cost growth observed in the overall health care system between 1985 and 2013, which is 1.4 percent.

- The underlying rates of excess cost growth gradually decline, over 75 years, to zero for Medicaid and private insurance premiums and to 1.0 percent for Medicare. CBO built in that difference because, in the absence of changes in federal law, state governments and the private sector have more flexibility to respond to the pressures of rising health care spending than the federal government does. Such a difference in growth rates could occur if, for instance, actions taken to reduce spending growth in the private sector weakened the incentives to develop and disseminate new medical technologies for nonelderly people but had a smaller effect on new technologies for diseases that principally affected the elderly.

- The underlying rate of excess cost growth in each sector declines in linear fashion—that is, by the same fraction of a percentage point each year. That linear decline, which CBO calls the underlying path of excess cost growth, reflects the agency's assessment that, over time, the steps needed to keep reducing growth rates will become increasingly onerous, but the pressure to take them will also intensify because of increasingly high health care spending.

Formulating Long-Term Projections

In CBO's extended baseline, projected federal spending for the major federal health care programs for the 2016–2025 period matches the projected spending in CBO's 10-year baseline. For 2026 and later years, the projection of federal spending is constructed as follows:

- For Medicare, excess cost growth in 2026 equals 0.9 percent, the average rate projected from 2023 through 2025 with certain adjustments.[60] It then increases by the same fraction of a percentage point each year for 14 years, so that in 2040 it matches the rate in the underlying path for that year, 1.3 percent. Altogether, by CBO's projections, excess cost growth for Medicare would average 0.8 percent per year during the 2016–2040 period. To generate estimates of total spending in the long term, CBO combined those projections of excess cost growth with estimates of the future number of Medicare beneficiaries. CBO estimates that the number of beneficiaries would grow with the size of the population age 65 and over and with the number of recipients of Social Security's Disability Insurance program.[61]

- For Medicaid, excess cost growth in 2026 equals 0.7 percent, the average rate projected from 2023 through 2025. It then increases by the same fraction of a percentage point each year for 14 years, so that in 2040 it matches the rate in the underlying path, 0.9 percent. According to the agency's projections, excess cost growth for the program would average 0.7 percent per year during the 2016–2040 period. To generate projections for Medicaid spending in the long term, CBO combined its projections of excess cost growth with estimates of the future number of Medicaid beneficiaries. States' future decisions about Medicaid eligibility and covered benefits are quite uncertain even over the next 10 years, and that uncertainty grows with time; accordingly, CBO adopted a formulaic approach to generating the number of Medicaid beneficiaries after the next decade. That approach takes into account population growth, increasing earnings, and prospective actions by states (see Appendix A).

- For private health insurance premiums, excess cost growth in 2026 is about 2 percent, the average rate projected from 2023 through 2025. It then decreases

60. Spending amounts were adjusted for the fact that, because of the quirks of the calendar, Medicare is scheduled to make 11, rather than the normal 12, capitation payments in Parts C and D of the program in 2024. In addition, the effect of sequestration was removed because that cancellation of funding will not affect spending after 2024. After those adjustments were made, the average projected rate of excess cost growth rate from 2023 through 2025 came to 0.8 percent. Under current law, payment rates for physicians' services in Medicare will remain at the 2019 level from 2020 through 2025, and they will increase annually starting in 2026. Those changes in the scheduled payment updates boost the projected excess cost growth rate in 2026 from 0.8 percent to 0.9 percent.

61. For more information about how CBO projects the number of beneficiaries of Social Security's Disability Insurance program, see Congressional Budget Office, *CBO's Long-Term Model: An Overview* (June 2009), www.cbo.gov/publication/20807, and Appendix A of this report.

by the same fraction of a percentage point each year for 14 years, so that in 2040 it matches the rate in the underlying path for that year, 0.9 percent. CBO projected the amounts of the exchange subsidies on the basis of excess cost growth for private health insurance premiums, the effects of the additional indexing factor described above, and growth in income (which reduces the share of the population that is eligible for subsidies).

- Under current law, funding for CHIP expires after September 2017. Following statutory guidelines, CBO assumes in its baseline spending projections that annual funding for the program from 2018 through 2025 will amount to $5.7 billion.[62] For 2026 and beyond, CBO assumes that spending on the program will equal the same share of GDP as the share in 2025.

All long-term economic and demographic developments are uncertain, but excess cost growth in health care may be particularly so. Pharmaceuticals, medical procedures and technology, and the delivery of care all continue to evolve rapidly, potentially making spending for any of the federal health care programs much higher or lower than CBO projects. Compounding the uncertainty imposed by those factors are the uncertain responses of beneficiaries and providers. For example, enrollees may be willing to accept more restrictions on their use of new services in return for lower premiums and cost-sharing requirements in Medicare Advantage plans. And if some insurers encourage or discourage the use of certain new drugs and technologies, the result may be changes in providers' behavior that affect the services received by people covered by other insurers. The number of beneficiaries in Medicaid and the exchanges is also very uncertain, because changes in the distribution of income and the steps that states may take regarding eligibility are unclear. Chapter 7 shows how CBO's projections would differ if the growth of costs per beneficiary in Medicare and Medicaid proved significantly higher or lower than the agency projects in the extended baseline.

62. See Congressional Budget Office, cost estimate for H.R. 2, the Medicare Access and CHIP Reauthorization Act of 2015 (March 2015), www.cbo.gov/publication/50053.

Long-Term Projections of Spending for the Major Health Care Programs

In CBO's extended baseline projections, which generally reflect current law, federal spending on the major health care programs increases significantly as a percentage of the economy in the coming decades.

Projected Spending

In 2015, federal spending for Medicare (net of offsetting receipts), Medicaid, CHIP, and the exchange subsidies will amount to 5.2 percent of GDP, CBO expects; net Medicare spending will equal 3.0 percent and federal spending on Medicaid, CHIP, and the exchange subsidies will equal 2.2 percent. In CBO's extended baseline, federal spending for those programs rises to 8.0 percent of GDP in 2040; net Medicare spending accounts for 5.1 percent and spending on Medicaid, CHIP, and the exchange subsidies for 2.9 percent (see Figure 2-2).[63] Gross Medicare spending is projected to increase from 3.5 percent of GDP in 2015 to 6.3 percent in 2040.

The projected rise in federal spending for the major health care programs relative to GDP results from the continued aging of the population, the expectation that health care costs per beneficiary will continue to grow somewhat faster than potential GDP per capita, and the continued increase in spending for federal subsidies for health care through Medicaid and the insurance exchanges over the next few years. In CBO's extended baseline, aging accounts for 43 percent of the programs' spending growth relative to GDP over the next 25 years, excess cost growth accounts for 45 percent, and an increased number of recipients of exchange subsidies and Medicaid benefits attributable to the ACA accounts for 12 percent (see Box 1-1 on page 24).

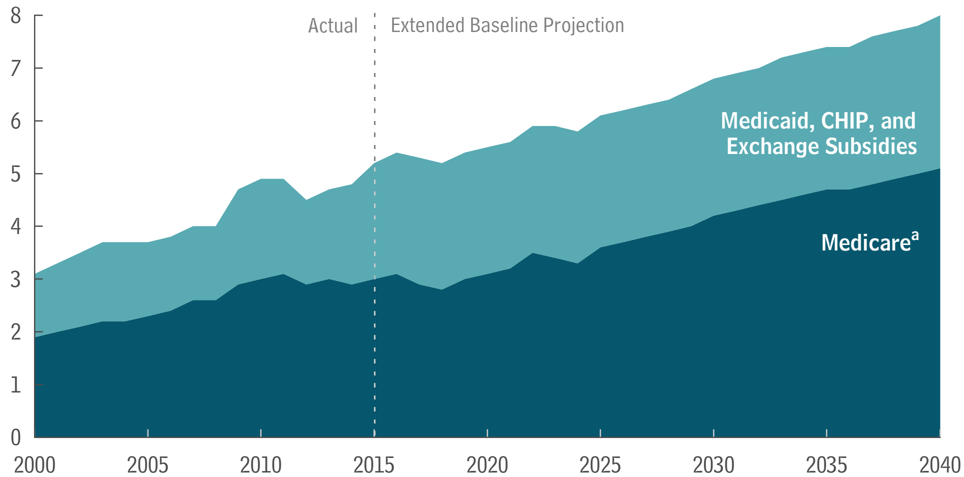
The factors that underlie the projected rise in total federal spending for the major health care programs also affect the amounts of spending that would subsidize care for different types of beneficiary. Although the ACA has

63. The projections in this chapter include the effects of the exchange subsidies on outlays; the smaller effects on revenues are included in the projections presented in Chapter 5. In all of the projections, the outlays for the exchange subsidies are presented in combination with outlays for Medicaid and CHIP; they all constitute federal subsidies for health insurance for low- and moderate-income households. Spending for the exchange subsidies includes related spending for risk adjustment.

Figure 2-2.

Federal Spending on the Major Health Care Programs, by Category

Percentage of Gross Domestic Product



The projected rise in federal spending for the major health care programs relative to GDP results from the continued aging of the population; the expectation that health care costs per person will continue to grow at a faster rate than potential GDP per capita; and, to a lesser extent, an increased number of recipients of exchange subsidies and Medicaid benefits attributable to the Affordable Care Act.

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

CHIP = Children's Health Insurance Program.

a. Net spending for Medicare refers to gross spending for Medicare net of offsetting receipts (from premium payments made by beneficiaries to the government and amounts paid by states from savings on Medicaid's prescription drug costs).

expanded federal support for health care regardless of people's health status, only about one-fifth of federal spending for the major health care programs in 2025 would finance care for able-bodied, nonelderly people, CBO projects in the extended baseline; about three-fifths would go toward care for people who are at least 65 years old, and about one-fifth toward care for blind and disabled people. After 2025, according to CBO's estimates in the extended baseline, the share of federal spending for the major health care programs that finances care for people who are at least 65 would rise slowly because of the continued aging of the population.

Among people who are at least 65, the fraction who will be significantly older than 65 will increase over the next 25 years (see Figure 2-3). That shift affects CBO's long-term projections because Medicare spending has traditionally been higher, on average, for the older people within the over-65 group. For example, in Parts A and B of the fee-for-service portion of Medicare in calendar year 2012, spending averaged about $5,000 for 66-year-olds, $8,500 for 75-year-olds, and $12,500 for 85-year-olds.[64] CBO expects that pattern to persist. One consequence of the pattern is that elderly beneficiaries over any given age receive a disproportionate share of the program's spending. For example, people who will be at least 75 years old in 2040 will represent about 56 percent of the elderly people enrolled in Medicare but will account for about 70 percent of the program's spending for elderly people, according to CBO's projections.

Although this chapter focuses on federal spending for health care, CBO also projected total national spending on health care (see Box 2-1). The agency combined its projections of federal spending on the major health care programs with rough projections of other health care spending. According to that analysis, which involves substantial uncertainty, national spending on health care as a share of GDP would continue to rise—from about

64. Calculating average spending for 65-year-old beneficiaries is not helpful for this comparison because most of them are enrolled in Medicare for only part of the calendar year in which they turn 65. The amounts reported here include spending under Parts A and B of Medicare averaged among all beneficiaries of each age enrolled in Part A, Part B, or both, within the traditional fee-for-service program. The fraction of beneficiaries enrolled in both Parts A and B increases as beneficiaries age.

Box 2-1.

National Spending on Health Care

National spending on health care increased from 9.5 percent of gross domestic product (GDP) in 1985 to 16.4 percent of GDP in 2013. In the Congressional Budget Office's extended baseline, which generally reflects current law, national spending for health care increases to about 25 percent of GDP by 2040.

CBO has only a limited ability to project national spending on health care, because the agency does not track all of the components of that spending as closely as it analyzes the components that are directly relevant to the federal budget. Therefore, to generate projections of national spending for health care, the agency combined its own projections for some categories of spending with projections for other categories developed by the Office of the Actuary in the Centers for Medicare & Medicaid Services (CMS).[1] The resulting projections were rough and involved substantial uncertainty—especially as they moved farther into the future—and therefore should be viewed with caution.

To project national spending for health care for the 2016–2025 period, CBO started with its projections of federal spending on the government's major health care programs. Other spending for health care includes payments by private health insurers, out-of-pocket payments by consumers, and other public spending. CBO estimated such spending by means of its own projections of payments by private health insurers and the Office of the Actuary's projections of out-of-pocket payments by consumers and of other public spending. Because the projections from CMS are available only through 2023, CBO used a historical rate of excess cost growth to extend them for the following two years.[2]

To project national spending for health care after 2025, CBO again started with its projections of federal spending on the government's major health care programs. It estimated other spending for health care by combining its projections of demographic and economic conditions with assumptions about excess cost growth for such spending. The starting point for projected excess cost growth in other health care spending was the weighted average rate of excess cost growth observed in the overall health care system between 1985 and 2013. CBO assumed that the rate of excess cost growth for other health care spending would slow from that historical rate—1.4 percent—in 2014 to zero over 75 years, in reaction to the pressures developing from rising health care spending. The slowdown was assumed to occur in linear fashion—that is, the rate of excess cost growth was assumed to decline by the same number of fractional percentage points each year.

1. This report defines total spending for health care as the health consumption expenditures in the national health expenditure accounts maintained by CMS. That definition excludes spending on medical research, structures, and equipment, and it includes out-of-pocket spending, payments made by public and private health insurance plans, spending on public health, and payments made by other third-party payers, such as workers' compensation.

2. Andrea M. Sisko and others, "National Health Expenditure Projections, 2013–23: Faster Growth Expected With Expanded Coverage and Improving Economy," *Health Affairs*, vol. 33, no. 10 (October 2014), pp. 1841–1850, http://dx.doi.org/10.1377/hlthaff.2014.0560.

17 percent of GDP now to about 25 percent by 2040—if current laws remained in place.

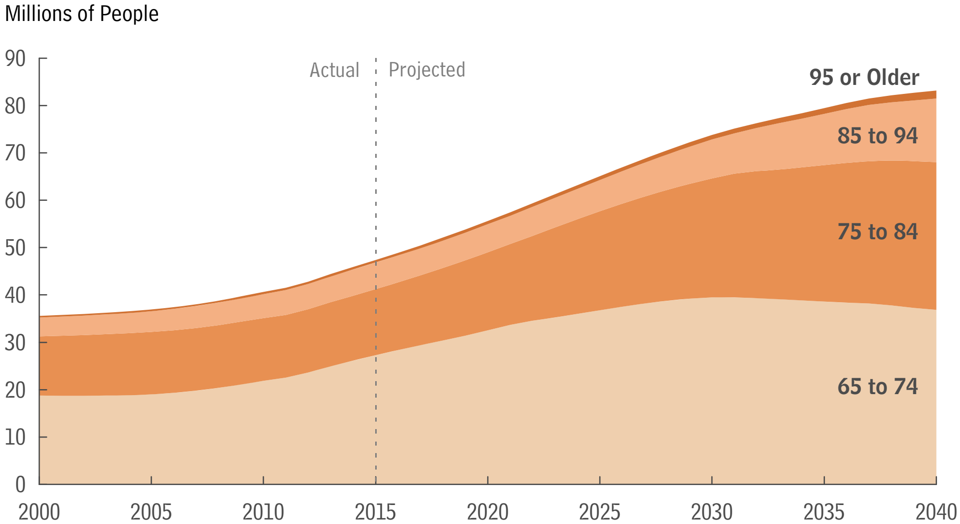
Projected Financing

Spending on the government's major health care programs is financed in various ways. For Medicaid and CHIP, states and the federal government share in the financing. The federal share of spending on those programs is funded entirely from the government's general fund, as are the outlays for subsidies provided through the health insurance exchanges.

In contrast, Medicare is funded mostly through a combination of dedicated taxes, beneficiaries' premiums, and

Figure 2-3.

Number of People Age 65 or Older, by Age Group



Per-person spending for Parts A and B of Medicare climbs with age: The program's average spending for an 85-year-old is more than twice that for a 66-year-old. Thus, average Medicare costs will rise as the number of people who are significantly older than 65 increases.

Source: Congressional Budget Office.

money from the government's general fund. The relative magnitudes of those sources of funding have changed significantly over time. Dedicated taxes have declined from 67 percent of gross federal spending for Medicare in 2000 to an estimated 40 percent in 2015 (see Figure 2-4). During the same period, the share of gross spending financed by offsetting receipts (mostly premiums paid by beneficiaries) has grown from 10 percent to an estimated 13 percent, and the share financed by the general fund and the remaining sources of funding for the program has increased from 23 percent to 47 percent. The increase in the share of spending covered by sources other than dedicated taxes is largely the result of an increase in the share of benefits provided by the parts of the program that are financed mainly by a combination of premiums and money from the general fund—Part B and, since 2006, Part D.[65] In CBO's extended baseline, receipts from dedicated Medicare taxes equal only 22 percent of gross federal spending for Medicare in 2040, and beneficiaries' premiums and other offsetting receipts account for 17 percent—leaving 61 percent financed by general funds and the remaining sources.

Benefits under Part A of Medicare are paid from the Hospital Insurance Trust Fund, which is credited with receipts largely from payroll taxes and from other revenues. A commonly used measure of the sustainability of Part A of Medicare is the timing of the projected exhaustion of the HI trust fund. According to CBO's baseline projections, under current law, the balance of the HI trust fund would increase from $202 billion at the end of fiscal year 2014 to $245 billion at the end of fiscal year 2020. Starting in 2021, CBO expects expenditures to outstrip income. By 2025, the fund's balance would be down to $156 billion.[66] CBO projects that the trust fund would be exhausted early in the 10-year period after 2025.[67]

Once the HI trust fund was exhausted, total payments to health plans and providers for services covered under Part A of Medicare would apparently be limited to the

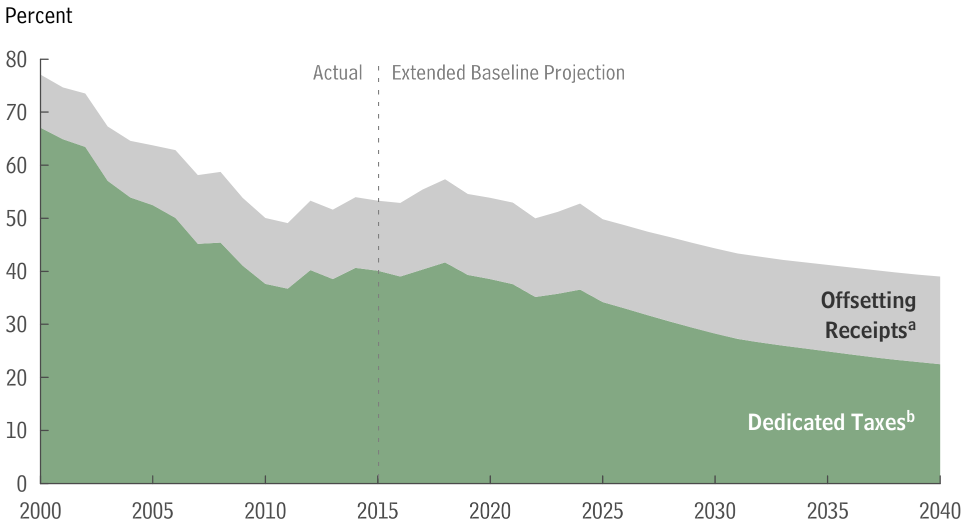
65. In 2000, Part B accounted for 41 percent of gross Medicare spending; in 2015, Parts B and D will account for 56 percent of gross Medicare spending, CBO estimates. In 2015, the percentage of benefits covered by premiums and other offsetting receipts would be higher than shown here if the two-thirds of Part D premiums paid directly by beneficiaries to Part D plans and the resulting benefit payments were included; however, they are not recorded in the federal budget.

66. Congressional Budget Office, "Medicare—Baseline Projections" (March 2015), www.cbo.gov/publication/44205. The estimate given is an updated one that reflects recently enacted legislation.

67. In contrast, the Supplementary Medical Insurance Trust Fund, which pays for benefits covered under Parts B and D of Medicare, cannot be exhausted, because it is financed mainly through premiums and money from the general fund. The amounts of contributions from those sources are set to cover the costs of those benefits.

Figure 2-4.

Medicare's Dedicated Taxes and Offsetting Receipts as a Share of Medicare Spending



Over the past several years, the share of Medicare spending funded by taxes and premiums has dropped. The share funded by the government's general fund has consequently grown.

Sources: Office of Management and Budget (actual shares up to 2014); Congressional Budget Office (projected shares).

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

a. Mostly premium payments made by beneficiaries to the government; also includes amounts paid by states from savings on Medicaid's prescription drug costs.

b. Payroll taxes and a portion of the federal income taxes paid on Social Security benefits.

amount of revenues subsequently credited to the trust fund. If that occurred, beneficiaries' access to health care services covered under Part A would almost certainly be reduced. However, for the purposes of these projections, CBO assumes that Medicare will pay benefits as scheduled under current law regardless of the status of the HI trust fund—an assumption that is consistent with a statutory requirement that CBO, in its 10-year baseline projections, assume that funding for an entitlement program is adequate to make all payments required by law for that program.[68]

Medicare Benefits and Payroll Taxes for People in Different Birth Cohorts

Over the course of their lifetimes, members of different generations will pay different amounts of Medicare payroll taxes and receive different amounts of Medicare benefits. Benefits will be a larger share of lifetime earnings for members of later generations, primarily because of the growth of health care spending per person but also because of increases in life expectancy, which will allow those people to receive benefits for longer periods, on average. Payroll taxes will be higher for later cohorts, because real earnings generally grow over time. Lifetime payroll taxes, however, will be about the same share of lifetime earnings, because payroll taxes are a fixed share of earnings.

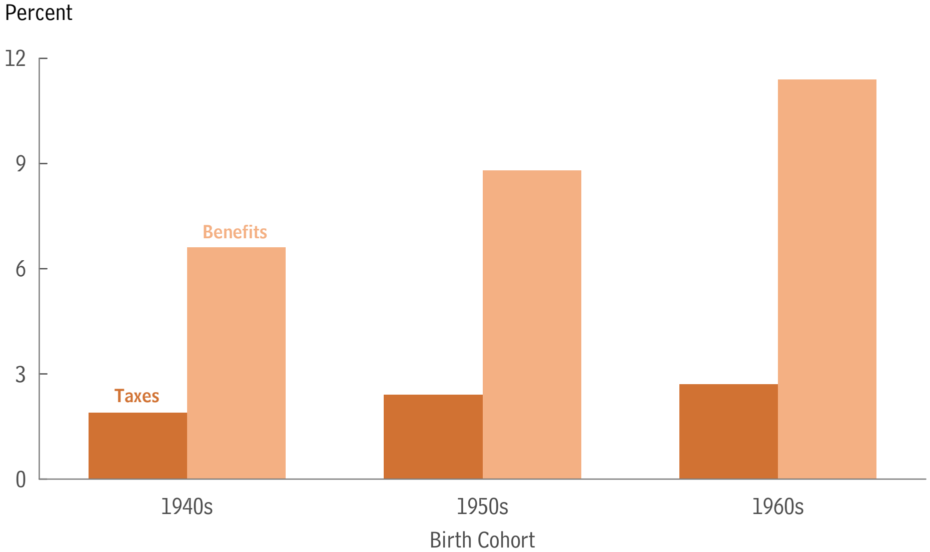
CBO estimated real lifetime benefits and payroll taxes for various birth cohorts as the present value, discounted to the year in which a beneficiary turns 65, of all benefits that a person receives from Medicare (net of premiums paid for those benefits) and all payroll taxes paid to the program (see Figure 2-5).[69] CBO estimates that, under the assumption that all scheduled benefits are paid, real

68. See section 257(b)(1) of the Balanced Budget and Emergency Deficit Control Act of 1985; 2 U.S.C. §907(b)(1).

69. For this analysis, benefits are those scheduled to be paid under current law, regardless of the balances projected for the HI trust fund. The present value of a flow of revenues or outlays over time is a single number that expresses that flow in terms of an equivalent sum received or paid at a specific time. The present value depends on a rate of interest (known as the discount rate) that is used to translate past and future cash flows into current dollars.

Figure 2-5.

Mean Lifetime Medicare Payroll Taxes and Benefits Relative to Lifetime Earnings, by Decade of Birth



Because of projected growth in health care spending per person and higher life expectancy, lifetime Medicare benefits will be a larger share of lifetime earnings for later generations.

Source: Congressional Budget Office.

Note: The amounts shown here are ratios of lifetime payroll taxes and benefits to lifetime earnings. Lifetime payroll taxes include all payroll taxes paid to the program. Payroll taxes consist of the employer's and employee's shares combined. Lifetime Medicare benefits include all benefits that a person is scheduled to receive from Medicare (net of premiums paid by beneficiaries to the government). To calculate present value, amounts are adjusted for inflation (to produce constant dollars) and discounted to age 65. The present value of a flow of revenues or outlays over time is a single number that expresses that flow in terms of an equivalent sum received or paid at a specific time. The present value depends on a rate of interest (known as the discount rate) that is used to translate past and future cash flows into current dollars. [Figure corrected on June 23, 2015]

average lifetime benefits (net of premiums paid) for each birth cohort as a percentage of lifetime earnings will generally be greater than those for the preceding cohort. For example, benefits received over a lifetime are projected to equal about 7 percent of lifetime earnings for people born in the 1940s, on average, but 11 percent for people born in the 1960s. By contrast, real average lifetime payroll taxes relative to lifetime earnings will rise from 2 percent for the 1940s cohort to almost 3 percent for the 1960s cohort.[70]

70. For people born in the 1940s and 1950s, lifetime payroll taxes as a share of lifetime earnings are lower than for later cohorts because those later cohorts face a higher statutory payroll tax rate for Hospital Insurance. That rate increased from 0.35 percent in 1966 to 2.9 percent in 1986, and it has stayed constant since.

[Text and footnote corrected on June 23, 2015]

CHAPTER

3

The Long-Term Outlook for Social Security

Social Security, which in 2015 marks its 80th anniversary, is currently the largest single program in the federal government's budget. The program consists of Old-Age and Survivors Insurance (OASI), which pays benefits to retired workers, to their dependents and survivors, and to some survivors of deceased workers; and Disability Insurance (DI), which makes payments to disabled workers and to their dependents until those workers reach the age of eligibility to receive full retirement benefits under OASI. Social Security currently has more than 59 million beneficiaries. The Congressional Budget Office estimates that mandatory outlays for Social Security will total $883 billion in fiscal year 2015, which will account for nearly one-quarter of all federal spending.[1]

During the program's first four decades, spending for Social Security increased sharply relative to the size of the economy—from less than 1 percent of gross domestic product (GDP) in the first few years to about 4 percent of GDP in the mid-1970s. That increase was caused largely by program expansions, including the creation in 1956 of the DI program. Spending rose to 4.8 percent of GDP in 1983, the year that marked the enactment of the last significant piece of legislation focused on Social Security. Between 1984 and 2007, Social Security spending fluctuated between 4.0 percent and 4.5 percent of GDP. During the 2007–2009 recession, GDP shrank, and the number of OASI and DI claimants rose unusually rapidly as the job market deteriorated. As a result, the program's outlays grew to 4.7 percent of GDP in 2009. CBO estimates that outlays for Social Security will be 4.9 percent of GDP in 2015.

In coming decades, more members of the baby-boom generation will reach retirement age and longer life spans will lead to longer retirements, so a much larger portion of the population will draw benefits. As a result, if the full benefits specified under current law are paid, CBO projects, Social Security spending would reach 6.2 percent of GDP in 2040 (see Figure 3-1).

How Social Security Works

Because 71 percent of its beneficiaries are retired workers or the spouses and children of those recipients, Social Security often is characterized as a retirement program.[2] In general, workers qualify for Social Security benefits if they are age 62 or older and have paid sufficient Social Security taxes for at least 10 years.

Social Security also provides other benefits, including payments to the survivors of deceased workers—about 10 percent of beneficiaries. In addition, workers who have not reached the full retirement age and who have had to limit employment because of a physical or mental disability can qualify for DI benefits—in many cases after a shorter period of employment than is required to collect retirement benefits. Disabled workers and their spouses and children account for 18 percent of beneficiaries.[3]

1. The $883 billion in mandatory outlays includes benefits paid ($878 billion), transfers to the Railroad Retirement Board ($5 billion), and payments to the U.S. Treasury for administrative costs (about $1 billion). CBO estimates that the Social Security Administration will spend an additional $6 billion, classified as discretionary outlays, on administration of the program. In this chapter, spending for Social Security generally refers to mandatory outlays.

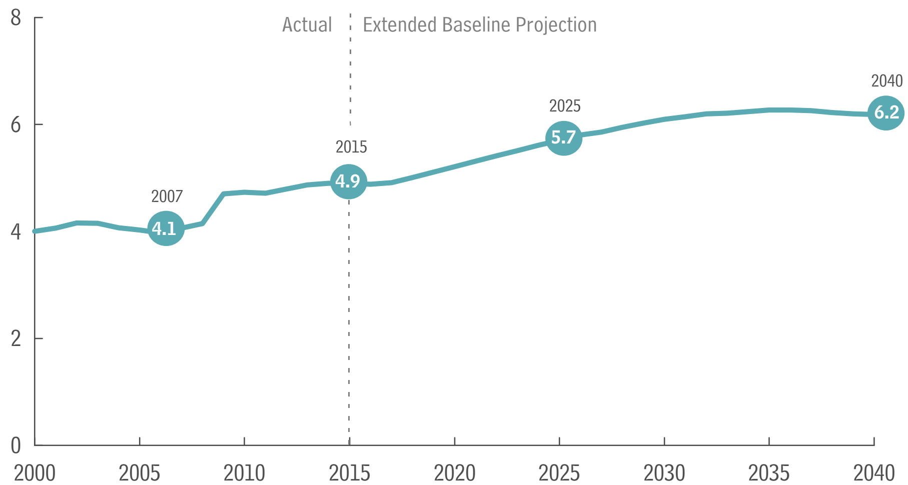
2. A more detailed description of the Social Security program is presented in Congressional Budget Office, *Social Security Policy Options 2015* (forthcoming).

3. See Congressional Budget Office, *Policy Options for the Social Security Disability Insurance Program* (July 2012), www.cbo.gov/publication/43421, and *Social Security Disability Insurance: Participation Trends and Their Fiscal Implications* (July 2010), www.cbo.gov/publication/21638.

Figure 3-1.

Spending for Social Security

Percentage of Gross Domestic Product



One effect of the 2007–2009 recession was a marked increase in spending for new Social Security recipients. The retirement of baby boomers is expected to increase spending over the rest of the projection period.

Source: Congressional Budget Office.

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

In dollar terms, about 70 percent of Social Security benefits are paid to retired workers and their dependents, survivors receive 13 percent, and disabled workers and their spouses and children receive 16 percent.[4]

Benefits

The benefits that retired or disabled workers initially receive are based on individual earnings histories. Those earnings and the formula used to compute initial benefits are indexed to changes in average annual earnings for the U.S. workforce as a whole (including earnings that are not subject to taxation under Social Security). In subsequent years, a cost-of-living adjustment is applied to benefits to reflect annual growth in consumer prices.

The calendar year in which a worker was born determines the age at which that worker becomes eligible to receive full retirement benefits. Workers born before 1938 were eligible to receive full retirement benefits at the age of 65. Under a schedule put in place by the Social Security Amendments of 1983, the full retirement age is increasing gradually: It reached 66 for people born between 1943 and 1954; it will gradually rise again, beginning with people born in 1955, who will turn 62 in 2017, reaching 67 for people born after 1959, who will turn 62 in 2022 or later. The early eligibility age—at which a worker qualifies for reduced retirement benefits—remains unchanged at 62.

The Social Security Administration has estimated that the initial average annual benefit was about $19,800 for a worker who retired in calendar year 2014 at the full retirement age of 66 and whose earnings (averaged over his or her career) equaled the national average.[5] That amount would replace about 44 percent of that worker's career-average earnings indexed by national average wage growth to 2008, the year in which that worker turned 60. In coming decades, replacement rates will be lower for workers with average earnings who retire at age 66 because of the scheduled increase in the full retirement age. Nevertheless, because initial benefits are based on

4. The ways in which beneficiaries and benefits are categorized are not completely consistent—some beneficiaries receive benefits in more than one category. For instance, retired workers who also receive survivors' benefits are classified as retired for the purpose of calculating the number of beneficiaries in each category. For the purpose of calculating the distribution of benefits, however, their benefit payments are prorated to the categories of retired worker and survivor.

5. See Michael Clingman, Kyle Burkhalter, and Chris Chaplain, *Replacement Rates for Hypothetical Retired Workers*, Actuarial Note 2014.9 (Social Security Administration, July 2014), Table C, www.socialsecurity.gov/OACT/NOTES/ran9.

beneficiaries' previous earnings indexed to overall average wage growth and because wages are expected to grow faster than inflation over the long term, in CBO's estimation, the real (inflation-adjusted) value of those initial benefits will rise over time.

Taxes

The Social Security program is funded by dedicated tax revenues from two sources. Today, roughly 96 percent comes from a payroll tax—generally, 12.4 percent of earnings that are subject to the Social Security tax. Workers and their employers each pay half; self-employed people pay the entire amount. Earnings up to a maximum annual amount—$118,500 in calendar year 2015—are subject to the payroll tax. That taxable maximum generally increases annually at the same rate as average earnings in the United States, and it has remained a nearly constant proportion of the average wage since the early1980s. Because earnings have grown more for high earners than for others, the portion of earnings covered by Social Security on which payroll taxes are paid has fallen from 90 percent in 1983 to 81 percent in 2015. CBO expects this disparity in growth in earnings to continue for at least the next decade; the portion of earnings that is subject to the Social Security tax is projected to fall to about 79 percent by 2025 and to decline slightly thereafter.

The remaining share of tax revenues—4 percent—is collected from income taxes on Social Security benefits. Recipients who file as single people must pay taxes on their benefits if the sum of their non–Social Security income (adjusted gross income plus nontaxable interest income) and half of their benefits exceeds $25,000; the threshold for joint filers is $32,000. Under current law, those thresholds will remain the same over time—no adjustments are made to account for earnings growth or for inflation.

Trust Funds

Revenues from the payroll tax and the tax on benefits are credited to the two Social Security trust funds (the OASI Trust Fund and the DI Trust Fund). Social Security benefits account for 99 percent of total outlays from the trust funds; the remaining 1 percent covers administrative costs. Interest on the balances is credited to the trust funds, but because the interest transactions represent payments from one part of the government (the general fund of the U.S. Treasury) to another (the Social Security trust funds), they do not affect federal budget deficits or surpluses. The trust funds' balances ($2.8 trillion at the end of April 2015) have accumulated over many years; during that time, tax revenues and interest received by the trust funds have exceeded the benefits paid out.

The Outlook for Social Security Spending and Revenues

Analysts have long projected that the cost of the Social Security program will rise significantly over the coming decades. Average benefits per recipient are expected to continue to grow because the earnings on which those benefits are based also will increase, and, other things being equal, that relationship would tend to keep total benefits roughly stable as a percentage of GDP. Moreover, as a larger share of the baby-boom generation reaches retirement age and as longer life spans lead to longer retirements, a significantly larger portion of the population will draw benefits. Those forces will combine to cause the total amount of benefits scheduled to be paid under current law to grow faster than the economy. However, total revenues for the program are anticipated to decline slightly relative to the size of the economy because most of the revenues come from the payroll tax, which has a flat rate (up to the taxable maximum, indexed to average earnings), and the proportion of earnings subject to that tax is expected to shrink. That faster growth in total benefits than in total revenues will create a shortfall in the program's finances. The extent of the shortfall and the amounts of Social Security benefits received and taxes paid by people born in different years will depend on changes in life expectancy and other factors.

CBO's extended baseline, which encompasses the period from 2015 through 2040, generally reflects the provisions of current law. The projections for Social Security spending and revenues are based on a detailed microsimulation model, which starts with data about individuals from a representative sample of the population and projects demographic and economic outcomes for that sample through time. For each individual in the sample, the model simulates birth, death, immigration and emigration, marital status and changes to it, fertility, labor force participation, hours worked, earnings, and payroll taxes, along with Social Security retirement, disability, and dependent benefits.[6]

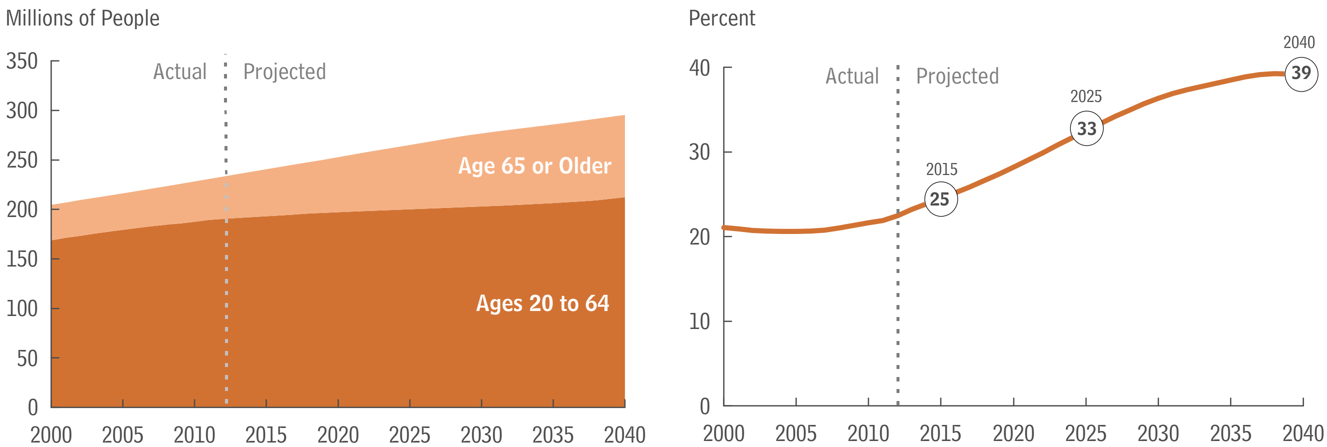
6. See Congressional Budget Office, *CBO's Long-Term Model: An Overview* (June 2009), www.cbo.gov/publication/20807.

Figure 3-2.

Changes in the Population, by Age Group

The number of people age 65 or older is expected to rise by 76 percent over the projection period, whereas the number between the ages of 20 and 64 will rise by just 10 percent.

Thus, by 2040, the proportion of the older to the younger group of people will have risen from the current 25 percent to nearly 40 percent.



Source: Congressional Budget Office.

Demographic Changes

According to CBO's projections, the number of people who are age 65 or older will increase by 37 percent between now and calendar year 2025 and by 76 percent between now and 2040. In comparison, CBO anticipates increases of just 4 percent and 10 percent in the population between the ages of 20 and 64 over those periods. Today, that older group is about one-quarter of the size of the younger group. The proportion is expected to increase to 33 percent by 2025 and to almost 40 percent by 2040 (see Figure 3-2). If current laws remained in place, more than 78 million people would collect benefits in 2025 and almost 100 million people would do so in 2040; currently, there are more than 59 million beneficiaries. (For more information on CBO's demographic projections, see Appendix A.)

After declining for several years, the average age of Social Security beneficiaries will begin to increase as the baby-boom generation continues to enter retirement. Currently, almost 12 percent of retired-worker beneficiaries over the age of 64 are at least 85 years old. As life expectancy increases, Social Security beneficiaries as a group will become older; by 2040, 19 percent of retired-worker beneficiaries over the age of 64 will be at least 85 years old.

CBO expects that future increases in life expectancy will be larger for people with higher lifetime earnings, which would be consistent with the pattern of past increases.[7] Today, a 65-year-old man whose household is in the highest quintile (the highest fifth) of lifetime earnings can be expected to live more than three years longer, CBO estimates, than a man of the same age whose household is in the lowest quintile of lifetime earnings; a 65-year-old woman in a household with high lifetime earnings can be expected to live more than a year longer than a woman of the same age in a household with low lifetime earnings. CBO projects that, on average by 2040, men in households with high lifetime earnings will live more than five years longer than men in households with low lifetime earnings, and women in households with high earnings will live almost three years longer than women in households with low earnings.

7. Life expectancy is the number of additional years a person is expected to live at a specified age. For more information on mortality differentials among groups with different earnings, see Congressional Budget Office, *Growing Disparities in Life Expectancy* (April 2008), www.cbo.gov/publication/41681; and Julian P. Cristia, *The Empirical Relationship Between Lifetime Earnings and Mortality,* Working Paper 2007-11 (Congressional Budget Office, August 2007), www.cbo.gov/publication/19096.

The projected changes in the life expectancy of people with high earnings relative to that of people with low earnings affect projections both of the total amount of Social Security benefits and of their distribution. Retirees with higher lifetime earnings receive larger benefits than retirees with lower earnings, so the greater increase in life expectancy of people in households with high lifetime earnings will raise total future benefits, all else being equal. Similarly, the greater increase in life expectancy of high earners will boost the ratio of lifetime Social Security benefits to lifetime Social Security taxes for high earners relative to that of low earners.[8]

Projected Spending and Revenues

If current laws remained in place, spending for Social Security would rise from 4.9 percent of GDP in 2015 to 6.2 percent by 2040, CBO estimates.[9] The share of Social Security spending on disability benefits would fall from 16 percent today to 13 percent in 2040. Most disabled beneficiaries are between age 50 and the full retirement age, and, as the baby-boom generation becomes older, the share of the population in that range will decline.

Between 2015 and 2040, Social Security revenues would grow more slowly than spending, according to projections in CBO's extended baseline. Because Social Security payroll tax receipts constitute a fixed share of taxable earnings, and taxable earnings are projected to decline as a share of GDP, payroll taxes also would decline as a share of GDP—from 4.2 percent in 2015 to 4.1 percent in 2040 (for further discussion, see Appendix A). However, both the number of Social Security recipients whose benefits are subject to taxation and their average income tax rates would increase, CBO projects. (For information about CBO's projections of total income taxes, see Chapter 5.) As a result, income taxes on Social Security benefits that are credited to the Social Security trust funds would grow from about 0.2 percent of GDP today to 0.3 percent of GDP in 2040. By that year, total Social Security tax revenues—payroll taxes plus taxes on benefits—would equal 4.4 percent of GDP, the same as the current amount.

In 2010, for the first time since the enactment of the Social Security Amendments of 1983, annual outlays for the program exceeded annual revenues excluding interest credited to the trust funds. A gap between those amounts has persisted since then, and in 2014 outlays exceeded noninterest income by about 9 percent. CBO now projects that, as more people in the baby-boom generation retire over the next 10 years, the gap will widen between amounts credited to the trust funds and payments to beneficiaries. According to CBO's extended baseline projections, if current laws remained unchanged, Social Security outlays would exceed the program's revenues by almost 30 percent in 2025 and by more than 40 percent in 2040.

Financing of Social Security

A common measure of the sustainability of a program that has a trust fund and a dedicated revenue source is its estimated actuarial balance over a given period—that is, the sum of the present value of projected tax revenues and the current trust fund balance minus the sum of the present value of projected outlays and a target balance at the end of the period.[10] For Social Security, that difference is traditionally presented as a percentage of the present value of taxable payroll. Over the next 75 years, if current laws remained in place, the program's actuarial

8. The ratio of lifetime benefits to taxes in Social Security depends on annual benefits and on the number of years for which benefits are collected. Beneficiaries with low lifetime earnings receive an annual benefit that replaces a larger portion of their average lifetime earnings than beneficiaries with high lifetime earnings, but they also tend to live for fewer years and therefore to collect benefits for a shorter period. All told, lifetime Social Security benefits as a share of lifetime earnings decrease as earnings rise, but estimates of that effect vary widely and depend on whether disabled and survivors' beneficiaries are included, how spousal benefits are accounted for, and how married couples are treated. For example, see Barry P. Bosworth and Kathleen Burke, *Differential Mortality and Retirement Benefits in the* Health and Retirement Study (April 2014), pp. 5–6, http://tinyurl.com/nqlhpyt.

9. CBO's projections incorporate the assumption that Social Security will pay benefits as scheduled under current law regardless of the status of the program's trust funds.

10. The present value of a flow of revenues or outlays over time is a single number that expresses that flow in terms of an equivalent sum received or paid at a specific time. The present value depends on a rate of interest (known as the discount rate) that is used to translate past and future cash flows into current dollars. To account for the difference between the trust fund's current balance and the balance desired for the end of the period, the balance at the beginning is added to the projected tax revenues and an additional year of costs at the end of the period is added to projected outlays.

Table 3-1.

Financial Measures for Social Security Under CBO's Extended Baseline

Projection Period (Calendar years)	Income Rate	Cost Rate	Actuarial Balance (Difference)
		As a Percentage of Taxable Payroll	
25 Years (2015 to 2039)	14.9	17.7	-2.8
50 Years (2015 to 2064)	14.2	17.9	-3.8
75 Years (2015 to 2089)	14.0	18.3	-4.4
		As a Percentage of Gross Domestic Product	
25 Years (2015 to 2039)	5.0	6.0	-0.9
50 Years (2015 to 2064)	4.7	6.0	-1.3
75 Years (2015 to 2089)	4.6	6.1	-1.4

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

Over the relevant periods, the income rate is the present value of annual tax revenues plus the initial trust fund balance, and the cost rate is the present value of annual outlays plus the present value of a year's worth of benefits as a reserve at the end of the period, each divided by the present value of gross domestic product or taxable payroll. The present value of a flow of revenues or outlays over time is a single number that expresses that flow in terms of an equivalent sum received or paid at a specific time. The present value depends on a rate of interest (known as the discount rate) that is used to translate past and future cash flows into current dollars. The actuarial balance is the difference between the income and cost rates.

To be consistent with the approach used by the Social Security trustees, the 25-, 50-, and 75-year projection periods for the financial measures reported here include 2015 and end in 2039, 2064, and 2089, respectively. See Social Security Administration, *The 2014 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* (July 2014), www.socialsecurity.gov/OACT/TR/2014.

shortfall would be 4.4 percent of taxable payroll, or 1.4 percent of GDP, CBO estimates (see Table 3-1).[11] Thus, given CBO's projections, actuarial balance could be achieved for Social Security through calendar year 2089 if payroll taxes were increased immediately and permanently by 4.4 percent of taxable payroll, if scheduled benefits were reduced by an equivalent amount, or if some combination of tax increases and spending reductions of equal present value was adopted.

The estimates of the actuarial shortfall do not account for revenues and outlays after the 75-year projection period. A policy that increased revenues or reduced outlays by the same percentage of taxable payroll in each year so as to eliminate the 75-year shortfall would not necessarily place Social Security on a permanently stable financial path. Instead, such a policy would create surpluses during the next several decades but generate deficits in later years and leave the system in a state of financial imbalance after calendar year 2089. If such a policy was adopted, the 75-year measure used in this report and commonly used in other analyses of Social Security would show no shortfall now because the measure includes the taxes paid by workers each year until 2089 but does not include the benefits that would be paid to those workers after that year.

11. To be consistent with the 75-year actuarial balance reported by the Social Security trustees, the 75-year projection period used here begins in calendar year 2015 and ends in calendar year 2089. The Social Security trustees estimated in 2014 that the program's 75-year actuarial shortfall was 2.9 percent of taxable payroll, 1.5 percentage points less than CBO estimates. The larger shortfall projected by CBO stems largely from three differences in the projections: CBO anticipates that life expectancy will increase somewhat more rapidly, the incidence of disability will be a little higher, and in the long run interest rates will be 0.6 percentage points lower. Taken together, all of the other factors that affect the actuarial shortfall would lead CBO and the trustees to make roughly the same estimate. For more details on CBO's projections, see Appendix A. For more details on the trustees' projections, see Social Security Administration, *The 2014 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* (July 2014), www.socialsecurity.gov/OACT/TR/2014.

The measure of actuarial balance used here is known as the 75-year open-group unfunded obligation because, with no change in law, the program would continue to be open to new participants. Those new participants would pay much more in taxes over the next 75 years than they would receive in benefits during that period.

An alternative measure—sometimes called the closed-group unfunded obligation—shows the shortfall in the system that would occur if the law was changed to close Social Security to anyone currently younger than age 15, thereby encompassing future taxes paid and benefits received only by people who are now age 15 or older. (Similar assessments are made of the financial outlook for private pension plans.) CBO estimates that, when measured as a percentage of the taxable payroll, the 75-year closed-group shortfall as of 2015 is about two-thirds larger than the 75-year open-group shortfall.

Another commonly used measure of Social Security's sustainability is the trust funds' date of exhaustion. Under CBO's extended baseline, the DI trust fund will be exhausted in fiscal year 2017 and the OASI trust fund will be exhausted in calendar year 2031. It is a common analytical convention, however, to consider the DI and OASI trust funds as combined, although legally they are separate. Therefore, this report focuses on the combined trust funds. In CBO's extended baseline, the combined OASDI trust funds are projected to be exhausted in calendar year 2029.

If a trust fund's balance declined to zero and current revenues were insufficient to cover benefits specified in law, the Social Security Administration would no longer have legal authority to pay full benefits when they were due. In the years after a trust fund's exhaustion, annual outlays therefore could not exceed annual revenues. Under those circumstances, all receipts to the trust fund would be used and the trust fund balance would remain essentially at zero.[12]

Social Security benefits can be projected in two different ways: as payable benefits, which conform to the limits imposed by a trust fund's balance, or as scheduled benefits, which reflect the benefit formulas specified in law, regardless of a trust fund's balance. This report uses the latter approach, which is consistent with a statutory requirement that CBO, in its 10-year baseline projections, assume that funding for entitlement programs is adequate to make all payments required by law.[13] In 2030, the year after the combined trust funds are expected to be exhausted, revenues are projected to equal 72 percent of scheduled outlays. Under those circumstances, payable benefits would be 28 percent less than scheduled benefits.

Social Security Benefits and Payroll Taxes for People in Different Birth Cohorts

People in different generations will, on average, end up paying different amounts of Social Security taxes and receiving different amounts of benefits over their lifetime.[14] Under current law, taxes and benefits alike would be higher for people born later because real earnings are projected to keep growing. Continuing increases in life expectancy also would contribute to growth in lifetime benefits because later cohorts would live to receive Social Security benefits for longer periods. To compare the effects of Social Security benefits and taxes on different generations, CBO calculated lifetime Social Security benefits and payroll taxes as the present value—discounted to the year in which the beneficiary turns 65—of all such benefits that workers would receive from the program or all payroll taxes they would pay to the program.[15] CBO measures the present value of benefits or taxes relative to the present value of lifetime earnings, with all values adjusted for inflation (see Figure 3-3). That analysis results in the following conclusions:

12. Noah P. Meyerson, *Social Security: What Would Happen If the Trust Funds Ran Out?* Report for Congress RL33514 (Congressional Research Service, August 2014). That report notes the entitlement created under the Social Security Act, cites other law that prohibits officials from making expenditures in excess of available funds, and acknowledges that the two create a potential conflict that must be resolved by the Congress or in the courts.

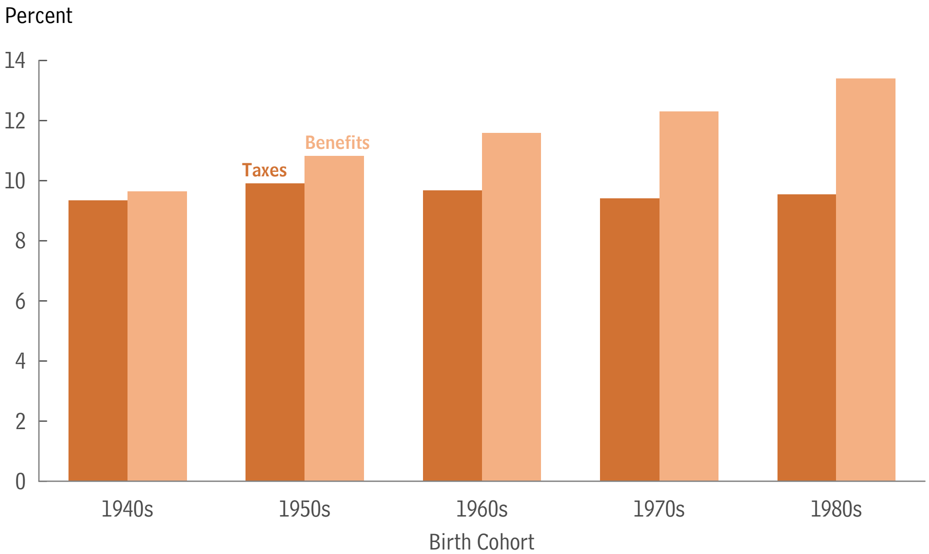
13. Section 257(b)(1) of the Balanced Budget and Emergency Deficit Control Act of 1985; 2 U.S.C. §907(b)(1).

14. For analysis of the distribution of Social Security benefits and taxes according to CBO's 2014 long-term projections, see Congressional Budget Office, *CBO's 2014 Long-Term Projections for Social Security: Additional Information* (December 2014), Exhibits 8–10, www.cbo.gov/publication/49795.

15. For this analysis, payroll taxes include the combined shares paid by employers and employees. Benefits are net of income taxes paid on benefits and credited to the Social Security trust funds. For discussion of the methods CBO used for these estimates, see Congressional Budget Office, *CBO's 2014 Long-Term Projections for Social Security: Additional Information* (December 2014), Appendix B, www.cbo.gov/publication/49795.

Figure 3-3.

Mean Lifetime Scheduled Social Security Taxes and Benefits Relative to Lifetime Earnings



An increase in life expectancy will mean that people born later will receive more in Social Security benefits (relative to their earnings) than those born earlier. Payroll taxes are not expected to keep pace, however, because they apply to a limited amount of earnings and that share of earnings subject to the tax is projected to decline for people born later.

Source: Congressional Budget Office.

Notes: The distribution of lifetime household earnings includes only people who live to at least age 45. Payroll taxes consist of the employer's and employee's shares combined. To calculate present value, amounts are adjusted for inflation (to produce constant dollars) and discounted to age 65. The present value of a flow of revenues or outlays over time is a single number that expresses that flow in terms of an equivalent sum received or paid at a specific time. The present value depends on a rate of interest (known as the discount rate) that is used to translate past and future cash flows into current dollars.

Lifetime Social Security benefits include all benefits paid to an individual except those received by young widows and children. Those benefits are excluded from this measure because there are insufficient data for years before 1984.

Scheduled benefits are benefits calculated under the Social Security Act, regardless of the balances in the program's trust funds.

- Real average lifetime scheduled benefits for each birth cohort as a percentage of lifetime earnings will generally be greater than those for the preceding cohort, and increases in life expectancy will cause that percentage to rise over time. For example, for people born in the 1950s, the mean amount of benefits received over a lifetime is projected to be about 11 percent of lifetime earnings. For people born in the 1980s, that amount will be 13 percent if they receive scheduled benefits.

- Real average lifetime payroll taxes for each birth cohort relative to lifetime earnings will generally be slightly less than those for the preceding cohort because of two factors: Under current law Social Security payroll taxes are a fixed share of earnings below the taxable maximum, and the portion of earnings that is subject to Social Security tax is projected to fall. For example, for people born in the 1950s, the mean amount of payroll taxes paid over a lifetime is projected to be about 10 percent of lifetime earnings. For people born in the 1980s, that amount will be 9.5 percent.

CHAPTER

4

The Long-Term Outlook for Other Federal Noninterest Spending

In 2015, almost half of the federal government's spending will go toward programs and activities other than the major health care programs (Medicare, Medicaid, the Children's Health Insurance Program, and the subsidies for health insurance purchased through exchanges), Social Security, and net interest. That spending—referred to in this report as other federal noninterest spending—includes outlays for discretionary programs, which are funded through the annual appropriation process, and outlays for mandatory programs other than the major health care programs and Social Security, which are usually funded according to laws that set eligibility and payment rules.[1] Mandatory spending in this category also includes the refundable portions of the earned income tax credit, the child tax credit, and the American Opportunity Tax Credit, which are recorded in the budget as outlays.

Under the broad assumptions used for this analysis, the Congressional Budget Office projects that other federal noninterest spending would drop from a total of 9.1 percent of gross domestic product (GDP) in 2015 to 7.4 percent in 2025 and then to 6.9 percent in 2040:

- Discretionary spending, which equals an estimated 6.5 percent of GDP in 2015, would fall to 5.1 percent of GDP by 2025; for its extended baseline, CBO assumed that discretionary spending would remain fixed at its percentage of GDP in 2025 (see Figure 4-1).
- Mandatory spending other than that for the major health care programs and Social Security would decrease from 2.6 percent of GDP this year to 2.3 percent in 2025. For its extended baseline, CBO assumed that such spending—other than the portion related to refundable tax credits—would continue to fall relative to GDP at the same rate that occurred over the 2020–2025 period. (Refundable tax credits are estimated as part of the revenue projections, which are described in Chapter 5.) Putting those pieces together, other mandatory spending is projected to equal 1.8 percent of GDP in 2040.

Other Federal Noninterest Spending Over the Past 50 Years

During the past 50 years, federal spending for everything other than the major health care programs, Social Security, and net interest has averaged 12 percent of GDP. Such spending equaled 13 percent of GDP in 1965, stayed between 12 percent and 15 percent from 1966 through 1987, and fell to around 8 percent in the late 1990s and early 2000s. By 2003, such spending had moved up to 10 percent of GDP, remaining close to that level through most of the first decade of the 2000s. It then spiked to 14 percent of GDP in 2009, before receding to 9 percent in 2014.

Discretionary Spending

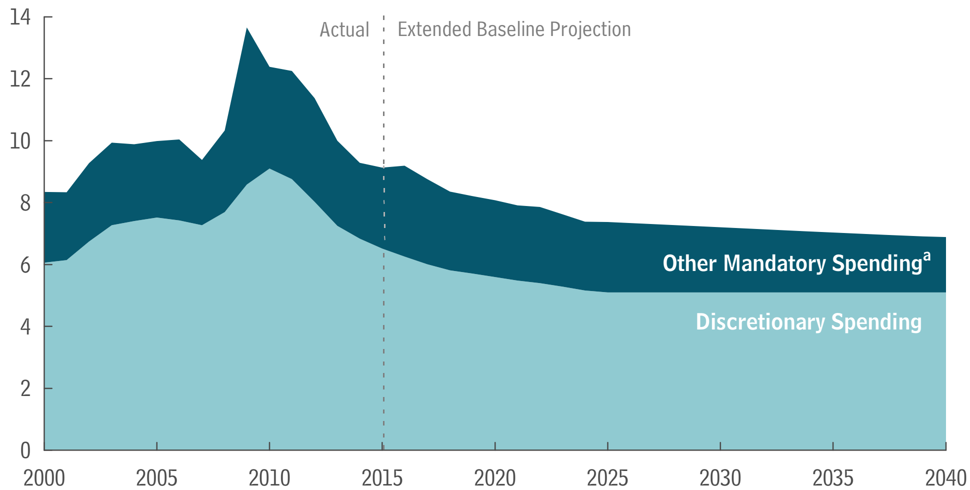
A distinct pattern in the federal budget since the 1970s has been the diminishing share of spending that occurs through the annual appropriation process. Between 1965 and 2014, discretionary spending declined from 66 percent of total federal spending to 34 percent. Relative to the size of the economy, that spending decreased from 10.9 percent of GDP to 6.8 percent.

1. For a description of the activities included in various categories of federal spending, see Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), Box 3-1, www.cbo.gov/publication/49892.

Figure 4-1.

Other Federal Noninterest Spending

Percentage of Gross Domestic Product



Other federal noninterest spending in CBO's extended baseline falls by 25 percent relative to gross domestic product between 2015 and 2040. Nearly two-thirds of that drop stems from the projected decline in discretionary spending over the next decade.

Source: Congressional Budget Office.

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

a. Other mandatory spending is all mandatory spending other than that for the major health care programs, Social Security, and net interest. It includes the refundable portions of the earned income and child tax credits and of the American Opportunity Tax Credit.

About half of discretionary spending is devoted to national defense and is administered primarily by the Department of Defense (DoD). That department's spending falls mostly into three broad categories:

- Operation and maintenance, which supports the day-to-day activities of the military, the training of military units, the majority of costs for the military's health care system, and compensation for most of DoD's civilian employees;
- Military personnel, which covers compensation for uniformed service members, including pay, allowances for housing and food, and related activities, such as moving service members and their families to new duty stations; and
- Acquisition, which includes procurement, research, development, testing, and evaluation of weapon systems and other major pieces of equipment.

Fifty years ago, in 1965, defense discretionary spending equaled 7.2 percent of GDP. It dropped below 5.0 percent of GDP in the late 1970s but averaged 5.9 percent during the defense buildup from 1982 to 1986 (see Figure 4-2). After the end of the Cold War, outlays for defense fell again relative to GDP, reaching a low of 2.9 percent at the turn of the century. Such outlays climbed again in the 2000s, mainly as a result of spending on military operations in Iraq and Afghanistan. Defense spending averaged 4.6 percent of GDP from 2009 through 2011, before falling to 3.5 percent in 2014.

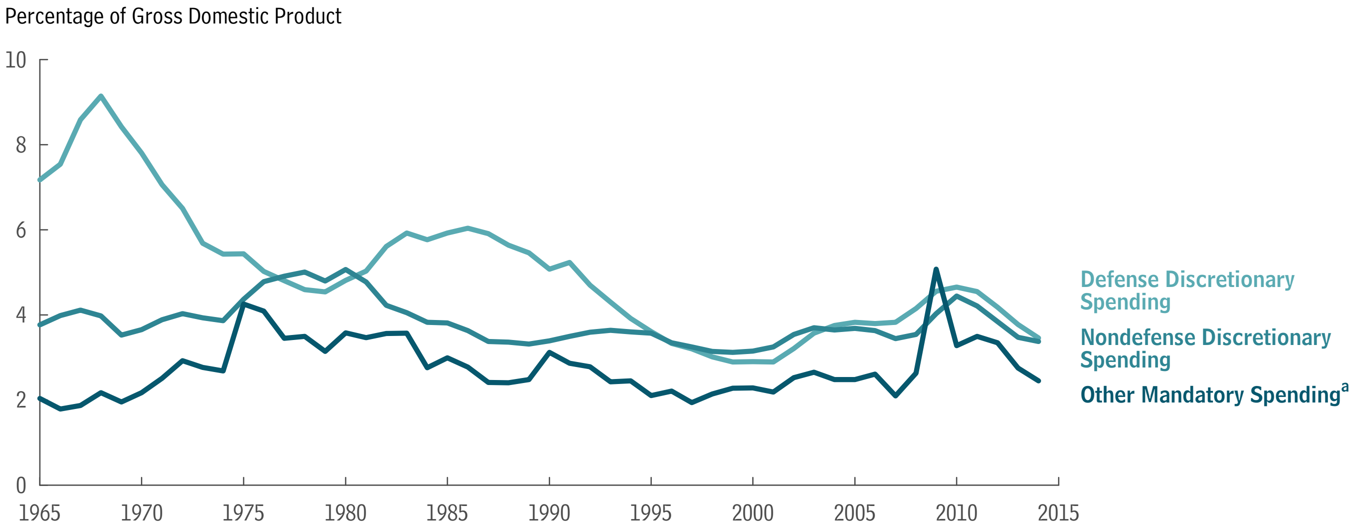
The rest of discretionary spending is for nondefense purposes. It covers a wide array of federal investment and other activities, including the following:

- Education (excluding student loans), training, employment, and social services;
- Transportation, including highway programs, transit programs, and airport security;
- Housing assistance;
- Veterans' health care;
- Health-related research and public health programs;
- Administration of justice, including federal law enforcement, criminal justice, and correctional activities;

Figure 4-2.

Other Federal Noninterest Spending, by Category, 1965 to 2014

Other federal noninterest spending is now about 30 percent lower as a percentage of gross domestic product (GDP) than it was in 1965. Lower defense discretionary spending—which is half the size it was, relative to GDP, in 1965—accounts for most of that reduction.



Source: Congressional Budget Office.

a. Other mandatory spending is all mandatory spending other than that for the major health care programs, Social Security, and net interest. It includes the refundable portions of the earned income and child tax credits and of the American Opportunity Tax Credit.

- International affairs, including international development, humanitarian assistance, peacekeeping, nuclear nonproliferation, and the operation of U.S. embassies and consulates; and

- Activities and programs in other areas, including natural resources and the environment, science, and community and regional development.

In 1965, nondefense discretionary spending amounted to 3.8 percent of GDP. Such spending remained close to 4 percent of GDP, on average, for the following decade but averaged almost 5 percent of GDP between 1976 and 1981. From 1984 to 2008, nondefense discretionary spending stayed between 3 percent and 4 percent of GDP. More recently, funding from the American Recovery and Reinvestment Act of 2009, as well as other funding associated with the federal government's response to the 2007–2009 recession, helped push nondefense discretionary spending above 4 percent of GDP from 2009 through 2011. Such spending dropped back to 3.4 percent of GDP in 2014.

Other Mandatory Spending

Mandatory spending other than that for the major health care programs and Social Security includes the following programs and activities:

- Civilian and military retirement, including benefits paid to retired federal civilian and military employees, and benefits paid to retired railroad workers;

- Earned income, child, and other refundable tax credits, for which payments are made to taxpayers for whom the credit exceeds their tax liability;

- Veterans' benefits, some of which are available to veterans only (such as housing, readjustment, disability compensation, and life insurance), and others of which are sometimes also available to dependents or survivors (such as educational assistance, pensions, dependency and indemnity compensation, and burial benefits);

- Food and nutrition programs, including the Supplemental Nutrition Assistance Program, (formerly known as the Food Stamp program), and child nutrition programs;

- Unemployment compensation;
- Supplemental Security Income; and
- Family support and foster care, including grants to states that help fund welfare programs, Temporary Assistance for Needy Families, foster care, and child support enforcement.

Other mandatory spending is net of various offsetting receipts, which are payments collected by government agencies from other government accounts or from the public in businesslike or market-oriented transactions and are recorded in the budget as negative outlays (that is, credits against mandatory spending). A significant share of offsetting receipts goes to the Medicare program (mostly in the form of premiums paid by beneficiaries) and is combined with Medicare outlays in this report (see Chapter 2 for more information). Other offsetting receipts come from the contributions that government agencies make to federal retirement programs, the proceeds from leases to drill for oil and natural gas on the Outer Continental Shelf, payments made to the U.S. Treasury by Fannie Mae and Freddie Mac, and other sources.

Other mandatory spending averaged about 2.5 percent of GDP from the mid-1960s through the mid-1970s. It then increased to about 3.5 percent of GDP, on average, from the mid-1970s through the early 1980s. It was generally lower from the mid-1980s to 2008, averaging about 2.5 percent of GDP. In 2009, however, other mandatory spending roughly doubled, to 5.1 percent of GDP, because of the financial crisis and recession and the federal government's response to them. As the economy has improved and the increases in spending related to the financial crisis and recession have waned, other mandatory spending has declined sharply relative to the size of the economy, falling to 2.5 percent of GDP in 2014.

Long-Term Projections of Other Federal Noninterest Spending

Under CBO's extended baseline, all federal spending apart from that for the major health care programs, Social Security, and net interest is projected to total 7.4 percent of GDP in 2025 and 6.9 percent in 2040. Those figures represent the lowest amounts relative to the size of the economy since the 1930s.

Discretionary Spending

Projections of discretionary spending for 2015 through 2025 come from CBO's most recent 10-year baseline budget projections, which were published in March.[2]

Through 2021, most discretionary appropriations are constrained by the caps put in place by the Budget Control Act of 2011 (as amended); for 2022 through 2025, CBO assumed that those appropriations would equal the 2021 amount, with increases for projected inflation. Funding for certain purposes, such as war-related activities, is not constrained by the Budget Control Act's caps; through 2025, CBO assumed, such funding would increase each year at the rate of inflation, starting from the current amount. Under those assumptions, outlays from discretionary appropriations are projected to decline from 6.5 percent of GDP this year—already well below the 50-year average of 8.8 percent—to 5.1 percent in 2025 (see Table 4-1). That 2025 amount would be the smallest share of discretionary spending relative to GDP in more than half a century (since at least 1962, the first year for which comparable data are available). Defense discretionary spending would equal 2.6 percent of GDP in 2025, and nondefense discretionary spending would equal 2.5 percent of GDP. Each of those amounts would also be the smallest as a share of the economy in at least five decades.

CBO's baseline and extended baseline are meant to be benchmarks for measuring the budgetary effects of legislation, so they mostly reflect the assumption that current laws remain unchanged. However, after 2021—when the caps established by the Budget Control Act are due to expire—total discretionary spending will not be constrained by current laws but instead will be determined by lawmakers' future actions. With no basis for predicting those actions, CBO based its long-term projections of discretionary spending on a combination of the baseline projections through 2025 and historical experience.

Specifically, after 2025, CBO's extended baseline incorporates the assumption that discretionary spending remains at the percentage of GDP projected for 2025—in other words, such spending grows at the same pace as the economy. In CBO's judgment, projecting a continued decline in discretionary spending as a share of GDP beyond 2025 would not provide the most useful benchmark for

2. See Congressional Budget Office, *Updated Budget Projections: 2015 to 2025* (March 2015), www.cbo.gov/publication/49973.

Table 4-1.

Other Federal Noninterest Spending Projected Under CBO's Baseline

Percentage of Gross Domestic Product

	2015	2025
Discretionary Spending		
Defense	3.2	2.6
Nondefense	3.3	2.5
Total	**6.5**	**5.1**
Other Mandatory Spending		
Civilian and military retirement	0.9	0.8
Nutrition programs	0.5	0.4
Refundable tax credits[a]	0.5	0.3
Veterans' benefits	0.5	0.4
Unemployment compensation	0.2	0.2
Supplemental Security Income	0.3	0.3
Offsetting receipts	-0.9	-0.5
Other	0.6	0.5
Total	**2.6**	**2.3**
Total, Other Federal Spending	**9.1**	**7.4**

Source: Congressional Budget Office.

Note: Other federal spending is all spending other than that for the major health care programs, Social Security, and net interest.

a. The earned income and child tax credits and the American Opportunity Tax Credit.

considering potential changes to discretionary programs, for several related reasons: First, discretionary spending has been a larger share of economic output throughout the past 50 years than it is projected to be in 2025. Second, nondefense discretionary spending has been higher than 3.0 percent of GDP throughout the past five decades and has shown no sustained trend relative to GDP. Third, defense spending has equaled at least 2.9 percent of GDP throughout the past five decades and has shown no trend relative to GDP in the past two decades. Conversely, projecting an increase in discretionary spending as a percentage of GDP beyond 2025 would require CBO to select a specific percentage, which the agency does not have a clear basis for doing. As a result of those considerations, CBO assumed for the extended baseline that discretionary spending would remain the same as a share of GDP after 2025 as CBO projects for 2025 in the 10-year baseline.

Other Mandatory Spending

In constructing its baseline projections, CBO assumes that mandatory programs will operate as they do under current law, which includes the automatic spending cuts put in place by the Budget Control Act.

In CBO's most recent baseline projections, total mandatory spending other than that for the major health care programs and Social Security is estimated to be 2.6 percent of GDP this year and to rise to 2.9 percent of GDP in 2016, primarily because of lower offsetting receipts. Such spending then declines in subsequent years, to 2.3 percent of GDP by 2025.[3]

Most of the projected decline in other mandatory spending relative to GDP through 2025 occurs because the number of beneficiaries for some of the programs is expected to decline relative to the size of the population as the economy expands and because average payments per beneficiary are projected to decrease relative to average income. For example, income thresholds for eligibility for some large income support programs, such as Supplemental Security Income and the Supplemental Nutrition Assistance Program, generally rise with prices, whereas income usually rises more rapidly—especially with the strengthening of the economy that CBO anticipates during the next several years. As a result, CBO expects, the number of beneficiaries in some programs will rise more slowly than the population or even decrease over the next 10 years. Furthermore, average payments under some large programs are often indexed to inflation and therefore tend to grow more slowly than income.

A small part of the decline between 2015 and 2025 stems from a projected reduction in spending for the earned income tax credit, the child tax credit, and the American Opportunity Tax Credit. Outlays for the refundable portions of those credits are projected to decrease from 0.5 percent of GDP in 2015 to 0.3 percent in 2025. About one-third of the decrease stems from the scheduled expiration of the American Opportunity Tax Credit and temporary increases in the earned income and child tax credits at the end of calendar year 2017, and about two-thirds is because, as income grows, the amounts of various credits that people qualify for decrease.

3. See Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), p. 16, www.cbo.gov/publication/49892.

For the years beyond 2025, CBO projected outlays for the refundable portions of the earned income and child tax credits as part of its long-term revenue projections (discussed in Chapter 5). The remainder of other mandatory spending was not projected in detail after 2025 because of the number of programs involved and the variety of factors that influence spending on them. Instead, CBO used an approximate method to project spending for those programs as a group, assuming that such spending would decline as a share of GDP after 2025 at the same rate at which it is projected to fall between 2020 and 2025. As benefits for some programs decline further relative to average income under current law, the benefits available to people many years in the future would differ markedly from what they are today.

Under the assumption that some benefits decline relative to average income, mandatory spending other than that for the major health care programs, Social Security, and refundable tax credits would decrease from 2.0 percent of GDP in 2025 to 1.6 percent by 2040. Including spending on those tax credits, other mandatory spending would equal 1.8 percent of GDP in 2040.

CHAPTER

5

The Long-Term Outlook for Federal Revenues

Federal revenues come from various sources, including individual and corporate income taxes, payroll (social insurance) taxes, excise taxes, estate and gift taxes, and other taxes and fees. Currently, proceeds from individual income taxes and payroll taxes account for about 80 percent of the federal government's revenues.

Projecting future revenue collections is difficult because revenues are sensitive to economic developments and because policymakers often make changes to tax law. For this report, the Congressional Budget Office projected the future path of revenues under an extended baseline. That approach follows the agency's baseline budget projections for the next decade and then extends the baseline concept beyond that 10-year window. The revenues projected for the 10-year window are the same as those in CBO's March 2015 baseline, as adjusted for recently enacted legislation.[1]

In general, the extended baseline reflects current law and embodies two assumptions about future federal tax policy:

- The rules governing individual income, payroll, excise, and estate and gift taxes will evolve as specified under current law (including the recent or scheduled expiration of temporary provisions lawmakers have routinely extended before); and
- Revenues from corporate income taxes and other sources (such as receipts from the Federal Reserve) will grow as projected under current law through 2025 and then remain constant as a share of gross domestic product (GDP) thereafter.[2]

Not intended to predict budgetary outcomes, the projections instead represent CBO's general assessment of future revenues if current laws remained unchanged. (Chapter 6 discusses the consequences of fiscal policies other than those that the extended baseline incorporates.)

Under the extended baseline, federal revenues as a share of GDP are projected to rise from 17.7 percent in 2015 to 18.3 percent in 2025. That growth largely reflects structural features of the tax system, most significantly because of real bracket creep—the pushing of a growing share of income into higher tax brackets because of growth in real (inflation-adjusted) income and the interaction of the tax system with inflation.

After 2025, in the extended baseline, revenues continue rising faster than GDP, largely for two reasons: The effect of real bracket creep continues, and certain tax increases enacted in the Affordable Care Act (ACA) generate a growing amount of revenues in relation to the size of the economy. As a result, federal revenues are projected to

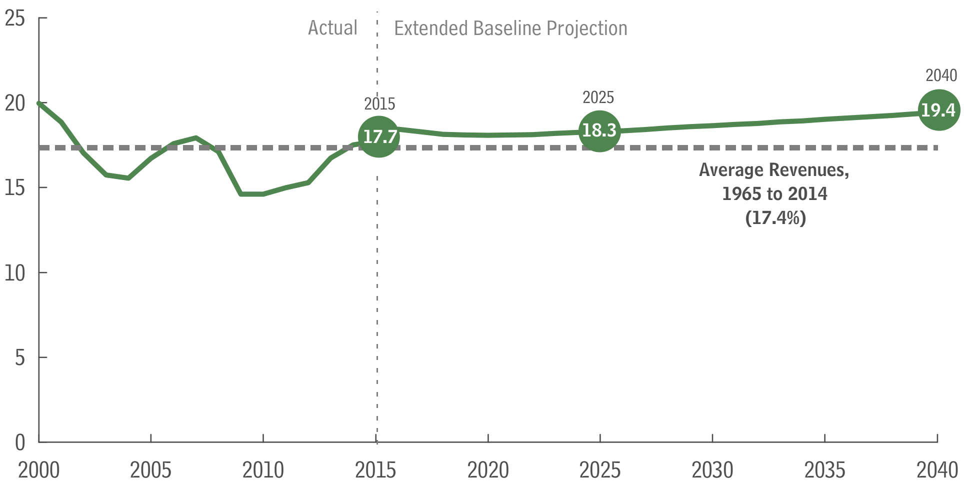
1. The baseline this chapter refers to is the baseline issued in March 2015, as adjusted to reflect legislation enacted after CBO prepared those projections. The only such legislation affecting revenues enacted before CBO made the current projections is Public Law 114-10, the Medicare Reauthorization and CHIP Extension Act of 2015, which became law on April 16, 2015. According to CBO's projections, that law will increase revenues by less than $1 billion in any given year between 2015 and 2025. For details of CBO's March baseline, see Congressional Budget Office, *Updated Budget Projections: 2015 to 2025* (March 2015), www.cbo.gov/publication/49973. For details of Public Law 114-10, see Congressional Budget Office, cost estimate for H.R. 2, the Medicare Access and CHIP Reauthorization Act of 2015 (March 25, 2015), www.cbo.gov/publication/50053.

2. The sole exception to the current-law assumption during the 10-year baseline period applies to expiring excise taxes dedicated to trust funds. The Balanced Budget and Emergency Deficit Control Act of 1985 requires CBO's baseline to reflect the assumption that those taxes would be extended at their current rates. That law does not stipulate that the baseline include the extension of other expiring tax provisions, even if lawmakers have routinely extended them before.

Figure 5-1.

Total Revenues

Percentage of Gross Domestic Product



Under CBO's extended baseline, revenues as a share of GDP rise slowly after 2025 mainly because of real bracket creep and certain tax increases enacted in the Affordable Care Act.

Source: Congressional Budget Office.

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

reach 19.4 percent of GDP by 2040 (see Figure 5-1).[3] By comparison, revenues over the past 50 years have averaged 17.4 percent of GDP. Without significant changes in tax law, the tax system's effects in 2040 would be quite different from what they are today. A larger share of each additional dollar of income that households earned would go to taxes, and households throughout the income distribution would pay more of their total income in taxes than households in similar places in that distribution pay today.

3. This chapter's revenue projections are based on CBO's benchmark projections of economic variables such as GDP, inflation, and interest rates. For the 2015–2025 period, the benchmark matches CBO's January 2015 economic forecast. For later years, the benchmark generally reflects the economic experience of the past few decades. The benchmark also incorporates two assumptions about fiscal policy—that debt held by the public is maintained at 78 percent of GDP, the level reached in 2025 in CBO's baseline budget projections, and that effective marginal tax rates on income from work and saving remain constant after that year. (Effective marginal tax rates on labor or capital income represent the percentage of an additional dollar of such income that is paid in federal taxes.) Thus, this chapter's economic benchmark and the revenue projections do not account for how the increase in marginal tax rates that would occur after 2025 under the extended baseline might affect people's behavior. Chapter 6 analyzes the economic impact of the debt levels and marginal tax rates that CBO projects under the extended baseline. For more about the economic benchmark, see Appendix A.

Revenues Over the Past 50 Years

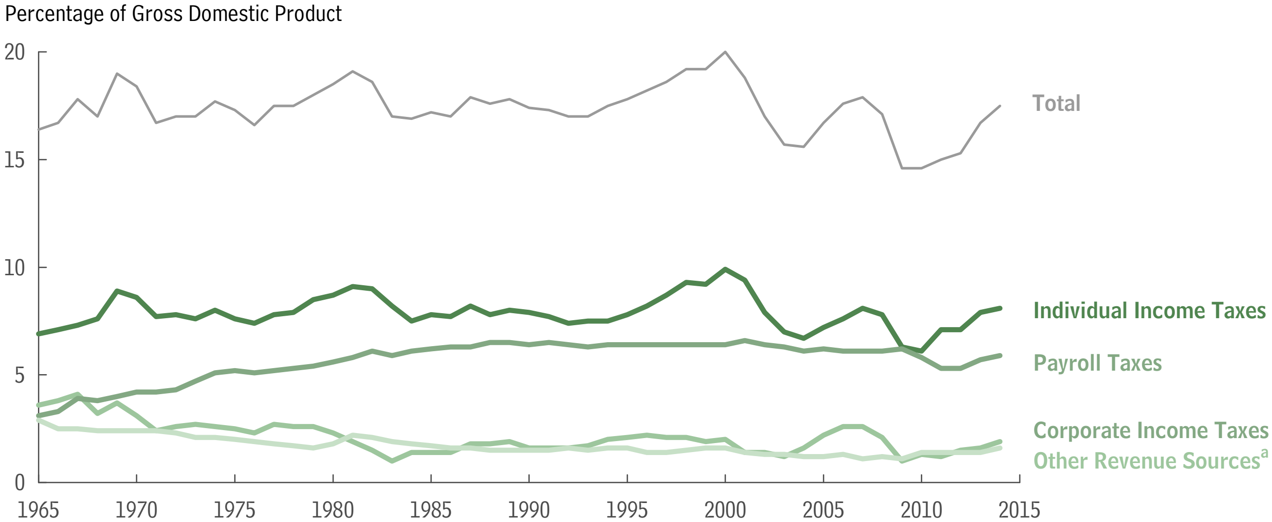
Over the past 50 years, total federal revenues have been as high as 20.0 percent of GDP (in 2000) and as low as 14.6 percent (in 2009 and 2010), with no evident trend (see Figure 5-2). The composition of total revenues during that period has varied as well. Individual income taxes, which account for about half of all revenues now, have ranged from slightly less than 10 percent of GDP (in 2000) to slightly more than 6 percent (in 2010). Payroll taxes, which generate about one-third of total revenues now, have varied from about 3 percent of GDP to more than 6 percent during the past 50 years. (Those taxes consist primarily of payroll taxes credited to the Social Security and Medicare Hospital Insurance trust funds.) Corporate income taxes have fluctuated between about 1 percent of GDP and 3 percent since the 1960s, as have combined revenues from other sources.

Some of the variation in the amounts of revenue that different taxes generated has stemmed from changes in economic conditions and from how those changes interact with the tax code. For example, without legislated tax reductions, real bracket creep tends to cause receipts from individual income taxes to grow in relation to GDP. Also, because some parameters of the tax system are not indexed to increase with inflation, rising prices alone subject a greater share of income to higher effective tax

Figure 5-2.

Revenues, by Source, 1965 to 2014

Over the past 50 years, total revenues averaged 17.4 percent of GDP; most of the variation around that average reflects variation in individual income tax receipts.



Source: Congressional Budget Office.

a. Consists of excise taxes, remittances to the U.S. Treasury from the Federal Reserve System, customs duties, estate and gift taxes, and miscellaneous fees and fines.

rates.[4] Cyclical developments in the economy also affect revenues. During economic downturns, for example, taxable corporate profits generally fall faster than the nation's output, shrinking corporate tax revenues in relation to GDP; losses in households' income also tend to push a greater share of total income into lower tax brackets, reducing individual income tax revenues in relation to GDP. Thus, total tax revenues as a share of GDP automatically decline when the economy is weak and rise when the economy is strong.

By contrast, revenues derived from excise taxes have declined over time in relation to GDP because many excise taxes are levied on the unit quantity of a good purchased (such as a gallon of gasoline) as opposed to a percentage of the price paid. Because those levies are not indexed for inflation, the revenues they generate have declined as a share of GDP as prices have risen.

Tax revenues as a share of GDP have also varied with legislative changes. In the past 50 years, at least a dozen changes in law have raised or lowered annual revenues by at least 0.5 percent of GDP.

Revenue Projections Under CBO's Extended Baseline

CBO's extended baseline follows the agency's March 2015 baseline budget projections, as adjusted for recently enacted legislation, for the next decade and then extends the baseline concept beyond that 10-year window.[5] The extended baseline reflects the assumptions that, after 2025, the rules governing the individual income, payroll, excise, and estate and gift taxes will evolve as specified under current law and that revenues from corporate income taxes and all other sources (such as receipts from the Federal Reserve) will remain constant as a share of GDP.

4. The parameters of the tax system include the amounts that define the various tax brackets; the amounts of the personal exemption, standard deductions, and credits; and tax rates. Although many of the parameters—including the personal exemption, standard deduction, and tax brackets—are indexed for inflation, some, such as the amount of the maximum child tax credit, are not. The effect of price increases on tax receipts was much more significant before 1984, when none of the parameters of the individual income tax were indexed for inflation.

5. See Congressional Budget Office, *Updated Budget Projections: 2015 to 2025* (March 2015), www.cbo.gov/publication/49973.

Table 5-1.

Sources of Growth in Total Revenues as a Percentage of GDP Between 2015 and 2040 Under CBO's Extended Baseline

Source of Growth	Percentage of GDP
Structural Features of the Individual Income Tax System (Including real bracket creep)[a]	1.3
New and Expiring Tax Provisions	0.7
Aging and the Taxation of Retirement Income	0.3
Other Factors (Including remaining changes in individual income taxes and all changes in corporate, payroll, excise, and estate and gift taxes)[b]	-0.6
Growth in Total Revenues Over the 2015–2040 Period	**1.7**

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

GDP = gross domestic product.

a. Real bracket creep refers to the phenomenon in which rising real (inflation-adjusted) income causes an ever-larger proportion of income to be subject to higher tax rates.

b. Excludes the effects on all those revenue sources of new and expiring tax provisions, which are accounted for in a preceding line of the table.

During the next decade, under current law, some new provisions of tax law will go into effect and certain provisions will expire. Reflecting those scheduled changes, the extended baseline incorporates the following assumptions:

- A new tax on certain employment-based health insurance plans with high premiums, scheduled to go into effect in 2018 as a result of the ACA, will be implemented without modification.

- Certain tax provisions that recently expired will not be extended later, and provisions scheduled to expire over the next several years will do so, even if lawmakers have routinely extended them before. For example, tax credits for research and experimentation expired at the end of December 2014 and will not be extended, and certain individual income tax credits will expire or decline in value after 2017.

If current laws remained in place, tax revenues would rise from 17.7 percent of GDP in 2015 to 18.3 percent in 2025 and then to 19.4 percent in 2040, CBO estimates. Increases in receipts from individual income taxes more than account for the projected rise of 1.7 percentage points in total revenues as a percentage of GDP over the next 25 years; receipts from all the other sources, taken together, are projected to decline slightly as a share of GDP.

The projected increase in tax receipts reflects several factors, including structural features of the income tax system, new and expiring tax provisions (including scheduled future tax changes enacted in the ACA), demographic trends, and other factors (see Table 5-1).

Structural Features of the Individual Income Tax System

Real bracket creep is the most important structural feature of the tax system contributing to growth in revenue over time. It has two kinds of effects. Rising real income subjects an ever-larger proportion of income to higher tax rates, and it further increases taxes by reducing taxpayers' eligibility for various credits, such as the earned income tax credit and the child tax credit.

Also, some provisions of the tax code are not indexed for inflation, so cumulative inflation generates some increase in receipts in relation to GDP. For example, the ACA imposed an additional tax on the investment income of individuals with income exceeding $200,000 and of families with income exceeding $250,000. Those thresholds are not indexed for inflation, so the tax will affect an increasing share of investment income over time and will boost revenues by a small but growing share of GDP.[6]

6. The ACA also imposed an additional Medicare tax of 0.9 percent, paid entirely by the employee, on earnings (wages and salaries) exceeding $200,000 for individuals and $250,000 for families. Because those thresholds are not indexed for inflation, the tax will apply to an increasing share of earnings over time and thereby raise payroll tax revenues as a share of GDP by larger amounts over time. However, a decline in the share of earnings subject to the Social Security tax will more than offset that effect, CBO projects, because a further slight increase in earnings inequality will cause more earnings to be above the taxable maximum for Social Security.

Revenues from the individual income tax also depend on the distribution of income. CBO's projections reflect an expectation that earnings will grow faster for higher-income people than for others during the next decade—as they have over the past several decades—and that the incomes of all taxpayers will grow at similar rates thereafter. Altogether, if current laws remained in place, growth in people's income would increase income tax revenues as a portion of GDP by 1.3 percentage points between 2015 and 2040, CBO estimates.

New and Expiring Tax Provisions

Under the extended baseline, CBO assumes that tax provisions will take effect or expire as specified under current law. Two tax provisions enacted in the ACA will go into effect over the next several years. Those new provisions will begin to raise revenues as a share of GDP after 2015. Certain other provisions—mainly providing tax credits—are scheduled to expire, also boosting revenue.

The most significant new provision, an excise tax on employment-based health insurance whose value exceeds certain thresholds, is scheduled to go into effect in 2018. That tax is expected to increase revenues in two ways:

- First, in those cases in which the tax applied, it would generate additional excise tax revenues.

- Second, many individuals and employers will probably shift to lower-cost insurance plans to either reduce the excise tax paid or avoid paying it altogether. As a result, total payments of health insurance premiums for those individuals—and the associated tax-exempt contributions from their employers—will be less than they would have been without the tax. However, CBO expects that total compensation paid by employers (including wages and salaries, contributions to health insurance premiums, pensions, and other fringe benefits) will not be affected over the long term.[7] Thus, smaller expenditures for health insurance will mean higher taxable wages and salaries for employees and, as a result, higher payments of income and payroll taxes.[8]

Thus, whether policyholders decided to pay the excise tax or to avoid it by switching to lower-cost plans, total tax revenues would ultimately rise compared with what they would have been without the tax. Although the threshold for the tax on high-premium health insurance plans is indexed for changes in overall consumer prices, health care costs will grow faster than prices over the long term, CBO projects. Consequently, more people will be affected over time.[9] Under the extended baseline, the excise tax is projected to increase total revenues by 0.5 percent of GDP in 2040.

The other ACA provision that will increase revenues in relation to GDP after 2015 penalizes certain employers that do not offer their employees health insurance coverage meeting certain criteria. That provision will be phased in over the 2015–2016 period and will increase revenues starting in 2016, CBO estimates.

In addition, several tax provisions either recently expired or are slated to expire over the next several years. Recently expired provisions include tax credits for research and experimentation as well as a deferral of tax payments on certain types of foreign-earned income, both of which had been in effect for many years. And after 2017, several credits in the individual income tax system are scheduled to expire or to be scaled back.[10]

Together, under the extended baseline, the scheduled introduction of new tax provisions and the expiration of certain existing tax provisions would raise receipts by 0.7 percent of GDP between 2015 and 2040, CBO projects.

7. In the past, rising premiums have been an important cause of slow wage growth. See Paul Ginsburg, *Alternative Health Spending Scenarios: Implications for Employers and Working Households* (Brookings Institution, April 2014), http://tinyurl.com/ksh9p47.

8. Even if the excise tax caused employers to shift to lower-cost health insurance plans without a corresponding increase in wages, other taxes, such as those on corporate profits, would tend to rise. The resulting revenues would be similar to the amounts projected in CBO's extended baseline.

9. The thresholds will be indexed to general inflation plus 1 percentage point for 2019 and to general inflation for 2020 and later years.

10. A provision allowing businesses to immediately deduct 50 percent of new investments in equipment from their taxable income expired at the end of calendar year 2014. That expiration causes significant movements in receipts over the next few years but contributes little to the growth of revenues as a share of GDP over the 2015–2025 or 2015–2040 period. Projected receipts in 2016, the first fiscal year that fully reflects the less favorable depreciation rules in effect under current law for 2015 and later years, are higher because of the smaller initial deductions for new investments. Over time, however, that effect diminishes as taxpayers take deductions for investments made under the less favorable rules.

Aging and the Taxation of Retirement Income

During the next few decades, members of the baby-boom generation (people born between 1946 and 1964) will continue to retire. They will withdraw money from retirement accounts and receive pension benefits, boosting income tax revenues as a share of GDP. Depending on the specific characteristics of retirement plans—such as 401(k) plans and individual retirement accounts—some or all of the amounts withdrawn will be taxable. Likewise, compensation deferred under employer-sponsored defined benefit plans is taxed when benefits are paid.[11] Thus, the U.S. Treasury will receive significant tax revenues that have been deferred for years. As a result, under the extended baseline, revenues as a share of GDP are projected to climb by about 0.3 percentage points between 2015 and 2040. That upward trend is expected to end around 2040, when almost all baby boomers will have reached retirement.

Other Factors

Under the extended baseline, factors besides those already discussed would cause revenues to decline by a combined 0.6 percent of GDP between 2015 and 2040. (The estimate reflects current law but does not consider scheduled changes to law and the structural and demographic effects of individual income taxes, which are accounted for separately.) About two-thirds of that decline would occur by 2025. In particular, remittances to the Treasury from the Federal Reserve—which have been very large since 2010 because the central bank's portfolio has grown and changed in composition—are projected to decline to more typical levels.

CBO also projects that, excluding the excise tax on high-premium health insurance plans, excise taxes would decline as a share of GDP over time. Many excise taxes are assessed as a fixed dollar amount per unit quantity of a good purchased, not as a percentage of the price paid. Therefore, as overall prices rise over time, receipts from excise taxes as a share of GDP tend to fall. Moreover, payroll taxes for unemployment insurance are expected to decline to more typical levels over the next few years, further reducing receipts as a share of GDP. Partly offsetting the declines in receipts is a small projected rise in individual income taxes for reasons other than structural features, scheduled changes in law, or aging and the taxation of retirement income.

Long-Term Implications for Tax Rates and the Tax Burden

Even if legislators enacted no future changes in tax law, the effects of the tax system that would be in place in the future would differ significantly from those of today's tax system. Increases in real income over time would push more income into higher tax brackets in the individual income tax system, raising people's effective marginal tax rates and average tax rates. (The effective marginal tax rate is the percentage of an additional dollar of income from labor or capital that is paid in federal taxes. The average tax rate is total taxes paid divided by total income.) Moreover, fewer taxpayers would be eligible for certain tax credits, such as the earned income and child credits, because rising real income would push taxpayers above the income limits for eligibility. Inflation would also raise tax rates, although to a much lesser extent because most of the tax code's key parameters are indexed for inflation. Slightly more taxpayers would become subject to the alternative minimum tax (AMT) over time, although the American Taxpayer Relief Act of 2012 greatly limited the share of taxpayers who would pay that tax.[12] Thus, in the long run, people throughout the income distribution would pay a larger share of their income in taxes than people at the same points in the distribution pay today, and many taxpayers would face diminished incentives to work and save.

Marginal Tax Rates on Income From Labor and Capital

Under CBO's extended baseline, marginal tax rates on income from labor and capital would rise over time. The effective marginal federal tax rate on labor income would,

11. A defined benefit plan is an employment-based plan that promises employees a certain benefit upon retirement. Typically, the benefit is based on a formula that takes into account an employee's length of service and salary.

12. The AMT is a parallel income tax system with fewer exemptions, deductions, and rates than the regular income tax system. Households must calculate the amount they owe under both tax systems and pay whichever is larger. The American Taxpayer Relief Act raised the exemption amounts for the AMT for 2012 and, beginning in 2013, permanently indexed those exemption amounts for inflation. Also indexed for inflation were the income thresholds at which those exemptions phase out and the income threshold at which the second rate bracket for the AMT begins. Although rising real income will gradually subject more taxpayers to the AMT, many of those newly affected will owe only slightly more than their regular income tax liability.

Table 5-2.

Estimates of Effective Marginal Federal Tax Rates Under CBO's Extended Baseline

Percent

	2015	2025	2040
Marginal Tax Rate on Labor Income	28.8	31.1	32.2
Marginal Tax Rate on Capital Income	18.0	18.4	18.5

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The effective marginal federal tax rate on income from labor is the share of an additional dollar of such income that is paid in federal individual income taxes and payroll taxes, averaged across taxpayers by using weights proportional to their labor income. The effective marginal federal tax rate on income from capital is the share of the return on an additional dollar of investment made in a particular year that will be paid in taxes over the life of that investment. Rates are calculated for different types of assets and industries and then averaged over all types of assets and industries, using the share of asset values as weights.

CBO projects, increase from 28.8 percent in calendar year 2015 to 32.2 percent in 2040 (see Table 5-2). (The effective marginal tax rate on labor income reflects labor income averaged across taxpayers by using weights proportional to their labor income.) By contrast, the effective marginal federal tax rate on capital income (returns on investment) is projected to rise only from 18.0 percent to 18.5 percent over that period.

The projected increase in the effective marginal tax rate on labor income reflects four primary factors:

- *Real bracket creep under the regular income tax.* As households' inflation-adjusted income rose over time, they would be pushed into higher marginal tax brackets. (Because the thresholds for taxing income at different rates are indexed for inflation, increases in income that just kept pace with inflation would not generally raise households' marginal tax rates.) One consequence is that the share of ordinary income subject to the top rate of 39.6 percent would rise from 12 percent in 2015 to 16 percent by 2040, CBO estimates.[13]

- *The structure of premium subsidies in health insurance exchanges (or marketplaces).* Those subsidies are conveyed in the form of tax credits that phase out as income rises over a certain range, increasing marginal rates on income in that range. Under current law, the income range over which the subsidies are phased out would expand with inflation, but the subsidies would grow faster than inflation. As a result, over time, for each extra dollar of income someone earns, the subsidy would be reduced by a larger fraction of that dollar, thereby raising the effective marginal tax rate.

- *Rising health care costs.* Rising health care costs tend to reduce marginal tax rates by reducing the taxable share of compensation. However, CBO expects that the excise tax on certain high-premium health insurance plans would more than offset this effect over the next few decades. That tax would affect a growing share of compensation over time because health care costs are expected to rise faster than the threshold for the tax.

- *The additional 0.9 percent tax on earnings above an established threshold that was enacted in the ACA.* Over time, that tax would apply to a growing share of labor income because the $250,000 threshold is not indexed for inflation.

The effective marginal tax rate on capital income would rise only slightly over the next 25 years, CBO projects. CBO estimates that real bracket creep would not raise that rate very much because a large share of capital income is already being taxed at top rates in 2015. Moreover, the other key factors that would push up the effective marginal tax rate on labor income would not affect the tax rate on capital income.

The increase in the marginal tax rate on labor income would reduce people's incentive to work, and the increase in the marginal tax rate on capital income would reduce their incentive to save. However, the reduced earnings and savings because of the higher taxes would also encourage people to work and save more in order to maintain the same amount of after-tax income and savings. Evidence suggests that the former behavioral responses typically prevail and that, on balance, higher

13. Ordinary income is all income subject to the income tax except long-term capital gains and dividends.

marginal tax rates discourage economic activity.[14] (The overall effect of federal taxes on economic activity depends not only on marginal tax rates but also on the amount of revenues raised in relation to federal spending and thereby on the resulting federal deficits and debt.) This chapter's analysis does not reflect those macroeconomic effects, which are discussed in Chapter 6.

Average Tax Rates for Some Representative Households

Some parameters of the tax code are not indexed for inflation, and most are not indexed for real income growth. As a result, the personal exemption, the standard deduction, the amount of the child tax credit, and the thresholds for taxing income at different rates all would tend to decline in relation to income over time under current law. One consequence is that, under the extended baseline, average federal tax rates would increase over time.

The cumulative effect of rising prices would significantly reduce the value of some parameters of the tax system that are not indexed for inflation, CBO projects. For example, CBO estimates that the amount of mortgage debt eligible for the mortgage interest deduction, which is not indexed for inflation, would fall from $1 million today to about $600,000 in 2040 measured in today's dollars. As another example, the portion of Social Security benefits that is taxable would increase from about 35 percent now to over 50 percent by 2040, CBO estimates, because the thresholds for taxing benefits are not indexed for inflation.

Under the extended baseline, even tax parameters that are indexed for inflation would lose value over time in comparison with income. For example, according to CBO's projections, the current $4,000 personal exemption would rise by almost 80 percent by 2040 because it is indexed for inflation. But income per household will probably almost triple during that period, so the value of the exemption in relation to income would decline by almost 40 percent. If income grew at similar rates for higher-income and lower-income taxpayers, that decline would tend to boost the average tax rates of lower-income taxpayers more than the average tax rates of other taxpayers because, for lower-income taxpayers, the personal exemption is larger in relation to income. For another example, CBO projects that without legislative changes, the proportion of taxpayers claiming the earned income tax credit would fall from 16 percent this year to 11 percent in 2040 as growth in real income made more taxpayers ineligible for the credit.[15]

Those developments and others would cause individual income taxes as a share of income to grow by different amounts over time for households at different points in the income distribution. For example:

- According to CBO's analysis, a married couple with two children earning the median income of $105,600 (including both cash income and other compensation) in 2015 and filing a joint tax return will pay about 4 percent of their income in individual income taxes (see Table 5-3).[16] By 2040, under current law, a similar couple earning the median income would pay 8 percent of their income in individual income taxes.

- For a married couple with two children earning half the median income, the change in individual income taxes as a share of income would be much greater, CBO estimates: In 2015, such a family will typically receive a net payment from the federal government equal to 10 percent of its income in the form of refundable tax credits, but by 2040 it would become a net taxpayer, paying about 1 percent of its income in income taxes.

- By comparison, for a married couple with two children earning four times the median income, CBO projects that the share of income that they would pay in individual income taxes would be much higher in both 2015 and 2040 but rise much less—from 19 percent to 22 percent—between those years.

14. For additional discussion, see Congressional Budget Office, *How the Supply of Labor Responds to Changes in Fiscal Policy* (October 2012), www.cbo.gov/publication/43674, and *Taxing Capital Income: Effective Marginal Tax Rates Under 2014 Law and Selected Policy Options* (December 2014), www.cbo.gov/publication/49817.

15. In CBO's projections, future family structures are similar to those today. If marriage rates among families with earnings near the eligibility range for the credit were to decline, for instance, the proportion of the population receiving the earned income tax credit would probably be higher than it would be otherwise, and vice versa.

16. The examples incorporate the assumption that all income that taxpayers receive is from labor compensation. Furthermore, median income is assumed to grow with average income, so income at each multiple of the median grows at the same rate. For details about the calculations, see Table 5-3.

Table 5-3.

Individual Income and Payroll Taxes as a Share of Total Income Under CBO's Extended Baseline

	Income (2015 dollars)[a]		Taxes as a Share of Total Income (Percent)	
	Cash	Total	Income Taxes[b]	Income and Payroll Taxes[c]
		Taxpayer Filing a Single Return		
Half the Median Total Income				
2015	11,300	18,300	-1	9
2040	17,600	29,600	2	11
Median Total Income				
2015	28,300	36,500	6	18
2040	45,100	59,200	7	19
Twice the Median Total Income				
2015	62,200	73,100	10	23
2040	100,100	118,400	12	25
Four Times the Median Total Income				
2015	130,800	146,100	15	27
2040	212,100	236,700	16	29
		Married Couple (With Two Children) Filing a Joint Return[d]		
Half the Median Total Income				
2015	32,900	52,800	-10	0
2040	52,900	85,500	1	11
Median Total Income				
2015	81,900	105,600	4	16
2040	132,300	171,000	8	19
Twice the Median Total Income				
2015	180,000	211,200	11	24
2040	291,100	342,000	14	28
Four Times the Median Total Income				
2015	384,700	422,400	19	29
2040	624,500	683,900	22	32

Source: Congressional Budget Office based on data from the March 2014 Current Population Survey.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

Cash income includes compensation from wages. Total income includes cash income, the employer's costs for employment-based health insurance, and the employer's share of payroll taxes. For 2040, the premium on employment-based health insurance is assumed not to exceed the excise tax threshold in the Affordable Care Act.

Taxpayers are assumed to itemize if itemized deductions are greater than the standard deduction. State and local taxes are assumed to equal 8 percent of wages; other deductions are assumed to equal 15 percent of wages.

a. Income amounts have been rounded to the nearest $100. Inflation adjustments are made using the personal consumption expenditures price index.

b. Negative tax rates result when refundable tax credits, such as the earned income and child tax credits, exceed the tax owed by people in an income group. (Refundable tax credits are not limited to the amount of income tax owed before they are applied.)

c. Payroll taxes include the share paid by employers.

d. The examples for a married couple reflect the assumption that the spouses earn the same amount.

By contrast, under current law, payroll taxes as a share of income would differ only slightly in 2040 from what they are today. Those taxes are principally levied as a flat rate on earned income below a certain threshold, which is indexed for both inflation and overall growth in real earnings. Thus, the changes over the next 25 years in the sum of income and payroll taxes as a share of income would be quite similar to the changes in income taxes as a share of income.

Although rising real income would contribute to rising average tax rates under current law, that real income growth would also mean that future households would have higher after-tax income than similar households at the same point in the income distribution have today. For example, from 2015 to 2040, CBO projects that real after-tax income for a couple earning the median income would grow by over 50 percent under the extended baseline.

CHAPTER

6

The Macroeconomic and Budgetary Effects of Various Fiscal Policies

Federal tax and spending policies have significant effects on the economy, and those macroeconomic effects, in turn, affect the budget. Although the budget projections presented in the preceding chapters of this report incorporate the effects of fiscal policy on the economy over the next decade, they do not incorporate those effects beyond 2025, relying instead on "benchmark" projections of economic variables. Unlike the economic forecast constructed by the Congressional Budget Office for the traditional 10-year baseline period, which generally reflects current laws regarding taxes and spending, the economic benchmark that CBO uses for projections beyond the 10-year period reflects the assumption that marginal tax rates (the rates that apply to an additional dollar of income) and the ratio of debt to gross domestic product (GDP) will remain constant after 10 years.

This chapter expands on the analysis in the preceding chapters in two ways. First, it shows how the budgetary policies that would be in place under the extended baseline would affect the economy in the long run—that is, how the economy that resulted from those policies would differ from CBO's economic benchmark—and how those macroeconomic effects would, in turn, feed back into the budget. Second, the chapter shows how the budget and the economy would evolve under three additional scenarios involving changes in fiscal policy. The first, the extended alternative fiscal scenario, incorporates changes to those policies assumed under the extended baseline that some analysts consider difficult to maintain; it would result in larger deficits and more debt than are projected in the extended baseline. The other two scenarios are illustrative. Through unspecified increases in tax revenue, cuts in spending, or some combination of the two, they would result in smaller deficits and lower debt than under the extended baseline.

Although changes in tax and spending policies can affect the economy in a variety of ways, CBO's analysis in this chapter focuses on the following four changes and their macroeconomic effects:

- Higher debt draws money away from (that is, crowds out) investment in capital goods and thereby reduces output below what would otherwise occur.
- Higher marginal tax rates discourage working and saving, which reduces output.
- Larger transfer payments to working-age people discourage working, which reduces output.
- Increased federal investment in education, research and development (R&D), and infrastructure helps develop a skilled workforce, encourages innovation, and facilitates commerce, all of which increase output.

For each of those policy changes, the opposite change has the opposite effect; for example, lower marginal tax rates increase output above what would otherwise occur.

Because the magnitude of the macroeconomic effects of specified changes in fiscal policies is uncertain, CBO reports not only a central estimate for the outcome of each set of policies but also a range of likely outcomes.[1] When estimating output, CBO focused on effects on

1. For certain key variables in its long-term economic models, CBO has developed ranges of values based on the research literature on those variables; each range is intended to cover roughly the middle two-thirds of the likely values for the variable. To calculate the ranges of estimates for the effects of each set of fiscal policies, CBO used the ranges of values for each variable. To calculate the central estimates, it used values for the variables at the midpoints of those ranges.

gross national product (GNP), which—unlike the more commonly cited GDP—includes the income that U.S. residents earn abroad and excludes the income that foreigners earn in this country; it is therefore a better measure of the resources available to U.S. households.

CBO estimates that the fiscal policies in the extended baseline would result in output lower than what is projected in the economic benchmark, primarily because the ratio of debt to output and marginal tax rates on labor income would increase significantly over time; in addition, the increase in debt would lead to higher interest rates. According to CBO's central estimates, real (inflation-adjusted) GNP in 2040 would be roughly 2 percent lower than the amount projected in the benchmark, and interest rates would be about a quarter of a percentage point higher.[2] Those economic changes, in turn, would worsen the budgetary outlook, though not dramatically: Under the extended baseline with macroeconomic feedback, federal debt held by the public is projected to rise to 107 percent of GDP in 2040; under the extended baseline without macroeconomic feedback (described in Chapter 1), it is projected to be 103 percent.

For the three additional fiscal scenarios, CBO's analysis yields the following macroeconomic and budgetary outcomes (according to the agency's central estimates):

- In the first scenario—that is, the extended alternative fiscal scenario—revenues and certain categories of spending measured as shares of GDP remain close to their historical averages over the long run rather than change as they would under the extended baseline. Under that scenario, deficits excluding interest payments would be about $2 trillion larger over the first decade than those under the baseline; thereafter, such deficits would be larger than those under the extended baseline by rapidly increasing amounts, doubling as a percentage of GDP in less than 10 years. CBO projects that real GNP in 2040 would be about 5 percent lower under the extended alternative fiscal scenario than under the extended baseline with macroeconomic feedback and that interest rates would be about three-quarters of a percentage point higher. As a result of those economic developments, federal debt would rise to 175 percent of GDP in 2040 (see Figure 6-1).

- Under the second scenario, which is illustrative and does not reflect any specific fiscal policies, deficit reduction is phased in such that total deficits excluding interest payments through 2025 are $2 trillion lower than those projected under the baseline and, in each subsequent year, the reduction measured as a percentage of GDP equals the 2025 reduction. CBO projects that real GNP in 2040 would be about 3 percent higher and interest rates would be about a third of a percentage point lower under this scenario than under the extended baseline with macroeconomic feedback. After accounting for those economic developments, CBO projects that federal debt in 2040 would be about 72 percent of GDP—about the same ratio as it was in 2013.

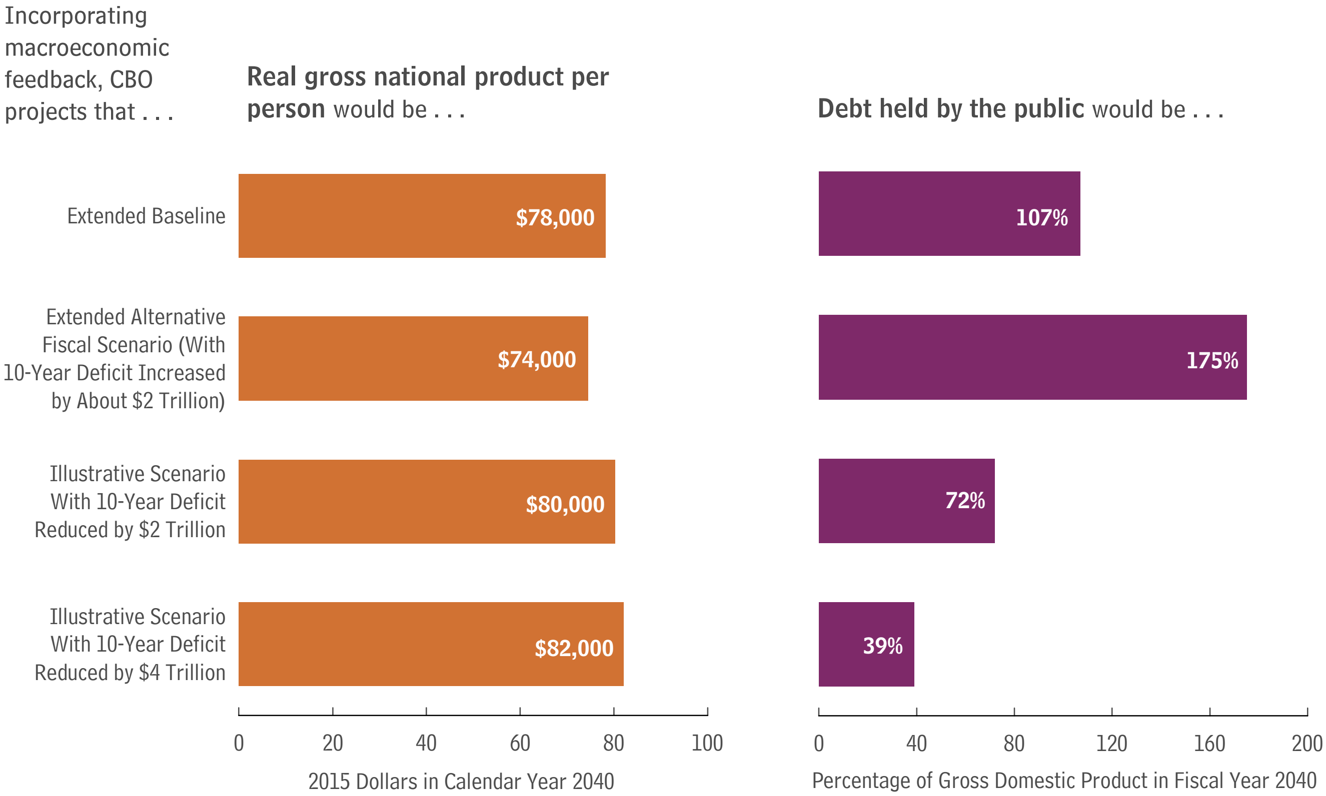
- Under the third scenario, which is also illustrative, the amount of deficit reduction in the next 10 years is twice as large as in the second, with the reduction phased in such that total deficits excluding interest payments through 2025 are $4 trillion lower than those under the baseline. As in the second scenario, measured as a percentage of GDP, the reduction in the deficit in each subsequent year equals the 2025 reduction. CBO projects that real GNP in 2040 would be about 5 percent higher and interest rates would be about two-thirds of a percentage point lower under this scenario than under the extended baseline with macroeconomic feedback. With those economic effects accounted for, federal debt would fall to 39 percent of GDP in 2040, slightly above its level in 2007 (35 percent) and its average over the past 50 years (38 percent).

The three additional fiscal scenarios would have significant effects on the economy during the next few years as well as over the long term (which is the focus of this chapter). The scenarios that would raise output in the long term above what is projected in the extended baseline would lower it in the short term, and the scenario that would reduce output in the long term would raise it in the short term. CBO estimates that the decrease in tax revenues and increase in spending under the extended alternative fiscal scenario would cause real GDP in 2016 to be 0.6 percent higher than it would be under current law and would cause the number of full-time-equivalent employees in 2016 to be 0.7 million greater than is

2. For the results presented in this chapter, changes in interest rates refer to changes in both the average real return on private capital and the average real interest rate on federal debt.

Figure 6-1.

Effects in 2040 of the Fiscal Policies in CBO's Extended Baseline, Extended Alternative Fiscal Scenario, and Illustrative Scenarios With Smaller Deficits



Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The extended alternative fiscal scenario incorporates these assumptions: Certain policies that have been in place for a number of years but that are scheduled to change will be continued, some provisions of law that might be difficult to sustain for a long period will be modified, and federal revenues and certain categories of federal spending measured as shares of gross domestic product will be maintained at or near their historical averages over the long term.

In the illustrative scenarios with the 10-year deficit reduced by $2 trillion and by $4 trillion relative to the baseline, those amounts are the cumulative reductions in deficits excluding interest payments between 2016 and 2025.

Real (inflation-adjusted) gross national product differs from gross domestic product, the more common measure of the output of the economy, by including the income that U.S. residents earn abroad and excluding the income that nonresidents earn in this country.

The results are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

projected under current law.[3] Under the first illustrative scenario, a drop in demand for goods and services would cause real GDP to be 0.2 percent lower and the number of full-time-equivalent employees to be 0.2 million smaller in 2016 than is projected under current law. Under the second illustrative scenario, which would bring about a larger decrease in demand, real GDP would be 0.3 percent lower and the number of full-time-equivalent employees would be 0.4 million smaller in 2016 than they would be under current law.

3. A year of full-time-equivalent employment is equal to 40 hours of employment per week for one year.

Long-Term Macroeconomic Effects of Federal Tax and Spending Policies

Federal tax and spending policies can affect the economy through many channels, including the amount of federal borrowing, marginal tax rates on labor and capital income, transfer payments to working-age people, and federal investment. To analyze medium-term to long-term effects of changes in federal tax and spending policies, CBO used an enhanced version of a model originally developed by Robert Solow in which people base their decisions about working and saving primarily on current economic conditions—especially wage levels, interest rates, and government policies. Their responses to changes in such conditions generally mirror their responses to economic and policy developments in the past; as a result, the responses reflect people's anticipation of future policies in a general way but not their expectations of particular future developments.[4]

How Increased Federal Borrowing Affects the Economy

Increased borrowing by the federal government generally crowds out private investment in productive capital in the long term. That is because the portion of the amount people save that is used to buy government securities is not available to finance private investment. The result is a smaller stock of capital and lower output in the long term than would otherwise be the case (all else held equal).

Two factors offset part of that crowding-out effect. One is that additional federal borrowing tends to boost private saving, which increases the total funds available to purchase federal securities and finance private investment. That response occurs for several reasons:

- Additional federal borrowing tends to raise interest rates, which boosts the return on saving;
- Some people anticipate that policymakers will raise taxes or cut spending in the future to cover the cost of paying interest on the additional accumulated debt, so those people increase their own saving to prepare for paying higher taxes or receiving less in benefits; and
- The policies that give rise to deficits (such as tax cuts or increases in government transfer payments) put more money in private hands, some of which is saved.

However, the rise in private saving is generally a good deal smaller than the increase in federal borrowing, so greater federal borrowing leads to less *national* saving.[5] CBO's central estimate, which is based on the research literature on this topic, is that private saving rises by 43 cents for every one-dollar increase in federal borrowing in the long run, leaving a net decline of 57 cents in national saving.

The second factor offsetting part of the crowding-out effect is that higher interest rates tend to increase net inflows of capital from other countries—by attracting more foreign capital to the United States and inducing U.S. savers to keep more of their money at home. Those additional net inflows prevent investment in this country from declining as much as national saving does in the face of more federal borrowing. CBO's central estimate, again drawn from the research literature on the topic, is that net inflows of private capital rise by 24 cents for every one-dollar increase in government borrowing in the long run.

However, an increase in inflows of capital from other countries also means that more profits and interest payments will flow overseas. Therefore, although flows of capital into the United States can help moderate a decline in domestic investment, part of the income resulting from that additional investment does not accrue to U.S. residents. The result is that greater net inflows of capital keep GDP from declining as much as it would otherwise, but they are less effective in restraining the decline in

4. For details of CBO's model, see Congressional Budget Office, *CBO's Method for Estimating Potential Output: An Update* (August 2001), www.cbo.gov/publication/13250. For a general explanation of how CBO analyzes the effects of fiscal policies, see Congressional Budget Office, *How CBO Analyzes the Effects of Changes in Federal Fiscal Policies on the Economy* (November 2014), www.cbo.gov/publication/49494.

5. National saving comprises total saving by all sectors of the economy: personal saving; business saving, in the form of after-tax profits not paid out as dividends; and government saving or dissaving, in the form of surpluses or deficits of the federal government and state and local governments.

GNP.[6] Thus, other things being equal, increases in debt cause a greater reduction in GNP than in GDP, and reductions in debt lead to a greater increase in GNP than in GDP.

With those two offsets to the crowding-out effect taken together, when the deficit goes up by one dollar, national saving falls by 57 cents and foreign capital inflows rise by 24 cents, leaving a net decline of 33 cents in investment in the long run, according to CBO's central estimates. To reflect the wide range of estimates in the economics literature of how government borrowing affects national saving and domestic investment, CBO also uses a range of estimates for those effects: At the low end of that range, for each dollar that deficits rise, domestic investment falls by 15 cents; at the high end of that range, domestic investment falls by 50 cents.[7]

The effect of deficits on investment alters pretax wages and the return on capital, changing incentives to work and save:

- Less investment leads to a smaller capital stock, which makes workers less productive and thereby decreases pretax wages below what they would otherwise be. Those lower wages reduce people's incentive to work.

- Less investment also increases the productivity of existing capital because more workers make use of each unit of capital—each computer or piece of machinery, for example. That greater productivity raises the return on capital. A higher return on capital boosts the return on equity shares in the ownership of capital and boosts the return on other investments (such as interest rates on federal debt) that are competing for private saving. The resulting increase in the return on saving makes saving more attractive.

CBO's estimates of the effects of higher federal debt on private saving, net capital inflows, and interest rates are based on historical experience. However, history may not be a good guide to the effects of rising debt in the extended baseline because the extended baseline shows a large, persistent increase in the ratio of debt to GDP—an outcome that is unprecedented in the United States, where large increases in debt have been temporary, such as those that occurred during and immediately after wars or severe economic downturns. If participants in financial markets came to believe that policymakers intended to allow federal debt as a percentage of GDP to continue to rise, interest rates would probably increase by more than the historical relationship between federal debt and interest rates suggests. In addition, the increases in federal debt might not affect private saving and net capital inflows in the same way that they have in the past.

As Chapter 1 discusses in greater detail, increased federal debt would, in the long term, have several negative consequences in addition to the effects just described:

- Increased borrowing would increase the amount of interest that the government pays to its lenders, all else being equal. Those larger interest payments would make it more difficult to reduce future budget deficits, necessitating larger increases in taxes or reductions in noninterest spending.

- Increased borrowing would restrict policymakers' ability to use tax and spending policies to respond to unexpected challenges, such as economic downturns or financial crises. As a result, those challenges would tend to have larger negative effects on the economy and on people's well-being.

- Increased borrowing would increase the probability of a fiscal crisis in which investors lost so much confidence in the government's ability to manage its budget that the government was unable to borrow at affordable rates. Such a crisis would present policymakers with extremely difficult choices and would probably have a very significant negative impact on the country.

6. The difference in the effect of an increase in debt on GDP and GNP depends, in large part, on the amount of additional capital that foreigners invest in the United States and on the rate of return that they receive on their investments. The increase in the return on capital in this country and the increase in net holdings of U.S. assets by foreigners—both of which imply greater income earned by foreign investors—decrease GNP relative to GDP. In CBO's analyses of fiscal policy, the rate of return earned by foreign investors in the United States changes when the rate of return on capital in this country changes. However, to be consistent with U.S. experience in recent decades, that response is less than one-for-one.

7. For a review of evidence about the effect of deficits on investment, see Jonathan Huntley, *The Long-Run Effects of Federal Budget Deficits on National Saving and Private Domestic Investment*, Working Paper 2014-02 (Congressional Budget Office, February 2014), www.cbo.gov/publication/45140.

How Increases in Marginal Tax Rates Affect the Economy

Increases in marginal tax rates on labor and capital income reduce output and income below what they would be with lower rates (all else held equal). A higher marginal tax rate on capital income (income derived from wealth, such as stock dividends, realized capital gains, and owners' profits from businesses) decreases the after-tax rate of return on saving, weakening people's incentive to save. However, because that higher marginal tax rate also decreases the return that they receive on their existing savings, people will need to save more to have the same future standard of living, which tends to increase the amount of saving. CBO concludes, as do most analysts, that the former effect outweighs the latter, meaning that a higher marginal tax rate on capital income decreases saving. Specifically, CBO estimates that an increase in the marginal tax rate on capital income that decreased the after-tax return on saving by 1 percent would result in a decrease in private saving of 0.2 percent. (A decrease in the marginal tax rate on capital income would have the opposite effect.) Less saving results in less investment, a smaller capital stock, and lower output and income.

Similarly, a higher marginal tax rate on labor income (such as wages and salaries) decreases people's incentive to work: Reduced after-tax compensation for an additional hour of work makes work less valuable than other uses of a person's time. That phenomenon, known as the substitution effect, tends to reduce the labor supply. However, because that higher marginal tax rate also decreases the after-tax income that they earn from the work they are already doing, people will need to work more to maintain their standard of living. That phenomenon, known as the income effect, tends to increase the labor supply. CBO concludes, as do most analysts, that the former effect outweighs the latter, meaning that a higher marginal tax rate on labor income decreases the labor supply. (A lower marginal tax rate on labor income would have the opposite effect.) Fewer hours of work result in lower output and income.

To reflect the high degree of uncertainty about the size of the effect that changes in marginal tax rates have on the number of hours people choose to work, CBO uses a range of values in its analyses of fiscal policy.[8] The responsiveness of the labor supply to taxes is often expressed as the total wage elasticity (the change in total labor income caused by a 1 percent change in after-tax wages). The total wage elasticity equals the substitution elasticity (which measures the substitution effect) minus the income elasticity (which measures the income effect). In this analysis, CBO's central estimate for the change in the labor supply in response to an increase in marginal tax rates corresponds to a total wage elasticity of 0.19 (composed of a substitution elasticity of 0.24 and an income elasticity of 0.05). CBO's range of likely changes in the labor supply is bounded at the low end by a total wage elasticity of about 0.06 (with a substitution elasticity of 0.16 and an income elasticity of 0.10) and at the high end by a value of about 0.32 (with a substitution elasticity of 0.32 and an income elasticity of zero).[9]

How Increases in Transfer Payments to Working-Age People Affect the Economy

Increases in transfer payments to working-age people discourage work by increasing the amount of resources available to those people and by making work less attractive than other uses of their time. An increase in payments raises people's income, so they can work less and maintain the same standard of living. That income effect tends to reduce the labor supply. In addition, an increase in transfer payments tends to create an implicit tax on additional earnings because those earnings cause people to receive reduced benefits from some transfer programs, thereby encouraging them to substitute other activities for work. That substitution effect also tends to reduce the labor supply. (Thus, in contrast with changes in marginal tax rates, changes in transfer payments generate income and substitution effects that generally work in the same direction.) Those reductions in the labor supply take the form of some people's choosing to work fewer hours and other people's choosing to withdraw from the labor force altogether.

In this analysis, CBO incorporates the income effect of changes in transfer payments to working-age people by using the same income elasticity that it uses to analyze the response of the labor supply to changes in marginal tax rates. This analysis does not, however, incorporate the substitution effect of changes in transfer payments

8. CBO uses those same values to estimate the effect on the labor supply of changes in pretax hourly wages.

9. For details on CBO's estimates of the responsiveness of the supply of labor to changes in the after-tax wage rate, see Congressional Budget Office, *How the Supply of Labor Responds to Changes in Fiscal Policy* (October 2012), www.cbo.gov/publication/43674.

because CBO is still developing methods for estimating the complex array of implicit taxes arising from federal transfer policies.

How Increases in Federal Investment Affect the Economy

Increases in federal investment promote long-term economic growth by raising productivity.[10] Spending on education helps develop a skilled workforce, spending on R&D encourages innovation, and spending on infrastructure such as roads and airports facilitates commerce. If not for receiving a public education (funded in part by federal spending), many workers would have lower wages than they do; the development of the Internet, initially funded through government R&D, led to the creation of whole segments of today's economy; and without public highways, the trucking industry would face much higher costs. The result of that greater productivity is higher private-sector output. By contrast, decreases in federal investment could reduce productivity and long-term growth.

CBO's central estimate is that federal investment yields, on average, one-half of the return of a comparable investment by the private sector.[11] However, the size of the return on federal investment is subject to considerable uncertainty, so CBO also uses a range of likely returns. At the low end, CBO uses a rate of return of zero on federal investment—which would mean that such investment has no effect on future private-sector output. At the high end, CBO uses a rate of return on federal investment equal to the average return on a comparable investment by the private sector. The actual rate of return for a particular federal investment could lie outside that range; a project might have a negative return or, alternatively, yield a greater return than a comparable private-sector investment.

Because of the nature of federal investment, CBO estimates that its returns accrue more slowly than do returns to private investment.[12] The agency expects that, on average, the full effect of federal investment on output is realized within eight years after the outlays are made. In particular, the agency expects that 10 percent of federal investment becomes productive within one year of investment, 20 percent in each of the next two years, and 10 percent in each of the fourth through eighth years following the investment.

Long-Term Effects of the Extended Baseline

The extended baseline generally incorporates the fiscal policies specified in current law. Those policies would cause deficits and debt as percentages of GDP to rise and marginal tax rates to increase over time. Those policies would also increase transfers to working-age families (primarily for health care) and reduce federal investment as a percentage of GDP. Together, those changes would make output lower and interest rates higher than projected in the economic benchmark. Those macroeconomic effects, in turn, would result in worse budgetary outcomes than those based on the economic benchmark.

Fiscal Policies in the Extended Baseline

Under the extended baseline, federal debt would be larger and marginal tax rates would be higher than the values CBO assumed for its economic benchmark after 2025. Furthermore, that benchmark does not reflect the increase in transfer payments and decline in federal investment as a share of GDP that are projected under the extended baseline.

Under the policies in the extended baseline, federal debt held by the public, which is currently 74 percent of GDP, would rise to 78 percent in 2025 and to 107 percent in 2040 (with macroeconomic feedback), CBO projects

10. For further discussion, see Congressional Budget Office, *Federal Investment* (December 2013), www.cbo.gov/publication/44974. This analysis focuses on federal investment for nondefense purposes. Defense investment contributes to the production of weapon systems and other defense goods, but much of it is sufficiently separate from domestic economic activity that it does not typically contribute to future private-sector output; the exception is the small portion of defense investment that goes to basic and applied research.

11. For a discussion of the macroeconomic effects of federal investment, see Congressional Budget Office, *The Macroeconomic and Budgetary Effects of Federal Investment* (forthcoming).

12. From 1988 to 2008, for example, 33 percent of nondefense federal investment was for education and 23 percent was for R&D; such investments, in CBO's assessment, take considerably longer to boost private-sector output than does the investment in physical capital that accounts for most private-sector investment.

(see Table 6-1).[13] Those percentages are larger than the ones underlying the economic benchmark, which incorporates the assumption that federal debt will rise to 78 percent of GDP by 2025 and then remain at that level thereafter.

In addition, marginal tax rates on labor and capital income would increase over time, as rising real incomes pushed more income into higher tax brackets. The effective marginal tax rate on labor income in 2040 would be about 32 percent and the rate on capital income would be about 19 percent; those rates are currently about 29 percent and 18 percent, respectively (see Chapter 5 for details). By contrast, the economic benchmark reflects the assumption that effective marginal tax rates on income from labor and capital will rise through 2025 in line with CBO's estimates under current law and remain at their 2025 levels (namely, 31 percent and 18 percent) thereafter.

Transfer payments to working-age people measured as a share of GDP would increase under the extended baseline, CBO projects. The macroeconomic effects of the increase in those payments over the coming decade are incorporated in CBO's baseline economic forecast for the 2015–2025 period and thus are incorporated in the economic benchmark. However, the further increase in those payments beyond 2025—which is expected to occur as rising federal spending for certain health care programs more than offsets declining federal spending (relative to the size of the economy) for some other transfer programs—is not included in the economic benchmark.

Given the assumptions underlying CBO's baseline, discretionary spending for nondefense purposes measured as a share of GDP is projected to decline significantly during the next decade and then to remain level thereafter (see Chapter 4 for details). Over the past two decades, about half of nondefense discretionary spending has been for investments in education, infrastructure, and R&D. If the share of such spending that goes to investment was the same as it has been in the past, then federal investment measured as a share of GDP would also fall markedly over the next decade and then remain at its 2025 level thereafter. The macroeconomic effects of such a reduction in investment are incorporated in CBO's baseline economic forecast and economic benchmark for the 2015–2025 period. The benchmark does not, however, include the effects of such a reduction beyond 2025.

Output and Interest Rates Under the Extended Baseline

In CBO's assessment, larger federal debt and higher marginal tax rates on labor income are the developments projected under the extended baseline that would have the largest effects on the economy. The projected rise in transfer payments and decline in federal investment as a share of GDP would also affect the economy, but to a lesser extent. That macroeconomic feedback would cause output and interest rates to differ from the amounts projected under CBO's economic benchmark, which does not account for such feedback.

Under the extended baseline, real GNP in 2040 would be about 2 percent below what is projected in the economic benchmark, CBO estimates.[14] As a result, real GNP per person in 2040 would be about $78,000 (in 2015 dollars), whereas it would be about $80,000 under the benchmark (which does not incorporate macroeconomic feedback); those amounts would be considerably greater than the estimated GNP per person in 2015 (about $57,000), primarily because of anticipated growth in productivity (see Figure 6-2). Interest rates in 2040 would be about a quarter of a percentage point higher than those projected in the benchmark, CBO estimates.

Those outcomes are CBO's central estimates. On the basis of the agency's ranges of likely outcomes for key variables, CBO estimates that under the extended baseline, real GNP in 2040 would probably be between about 1 percent and about 4 percent lower than in the benchmark. The estimated increase in interest rates in 2040 would probably range from one-tenth to one-half of a

13. Some combination of increases in revenues or reductions in noninterest spending that resulted in deficits that were 1.1 percent of GDP lower than those projected in the extended baseline would be necessary in each year over the 2015–2040 period to return debt as a percentage of GDP to its current level in 2040. To return debt to its average percentage of GDP over the past 50 years (38 percent), the annual deficits would have to be 2.6 percent of GDP lower than under the extended baseline. For a discussion of how CBO constructs those measures, see Chapter 1. The estimates here, like those in Chapter 1, are calculated without macroeconomic feedback.

14. Projected real GNP in 2025 under the extended baseline equals that in the economic benchmark because during the 10-year budget window, the benchmark matches CBO's economic forecast, which is consistent with the baseline tax and spending policies, and includes macroeconomic feedback.

Table 6-1.

Long-Run Effects on the Federal Budget of the Fiscal Policies in Various Budget Scenarios

Percentage of Gross Domestic Product

	2025	2040
Without Macroeconomic Feedback	**Revenues**	
Extended baseline	18.3	19
With Macroeconomic Feedback		
Extended baseline	18.3	19
Extended alternative fiscal scenario (with 10-year deficit increased by about $2 trillion)	18.0	18
Illustrative scenario with 10-year deficit reduced by $2 trillion	n.a.	n.a.
Illustrative scenario with 10-year deficit reduced by $4 trillion	n.a.	n.a.
Without Macroeconomic Feedback	**Spending Excluding Interest Payments**	
Extended baseline	19.2	21
With Macroeconomic Feedback		
Extended baseline	19.2	21
Extended alternative fiscal scenario (with 10-year deficit increased by about $2 trillion)	19.7	25
Illustrative scenario with 10-year deficit reduced by $2 trillion	n.a.	n.a.
Illustrative scenario with 10-year deficit reduced by $4 trillion	n.a.	n.a.
Without Macroeconomic Feedback	**Deficit (-) or Surplus Excluding Interest Payments**	
Extended baseline	-0.9	-2
With Macroeconomic Feedback		
Extended baseline	-0.9	-2
Extended alternative fiscal scenario (with 10-year deficit increased by about $2 trillion)	-1.6	-7
Illustrative scenario with 10-year deficit reduced by $2 trillion	0.5	*
Illustrative scenario with 10-year deficit reduced by $4 trillion	1.9	1
Without Macroeconomic Feedback	**Total Deficit (-) or Surplus**	
Extended baseline	-3.8	-6
With Macroeconomic Feedback		
Extended baseline	-3.8	-7
Extended alternative fiscal scenario (with 10-year deficit increased by about $2 trillion)	-5.0	-15
Illustrative scenario with 10-year deficit reduced by $2 trillion	-2.1	-3
Illustrative scenario with 10-year deficit reduced by $4 trillion	-0.4	*
Without Macroeconomic Feedback	**Federal Debt Held by the Public**	
Extended baseline	78	103
With Macroeconomic Feedback		
Extended baseline	78	107
Extended alternative fiscal scenario (with 10-year deficit increased by about $2 trillion)	87	175
Illustrative scenario with 10-year deficit reduced by $2 trillion	68	72
Illustrative scenario with 10-year deficit reduced by $4 trillion	59	39

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections, which include macroeconomic feedback, through 2025 and then extending the baseline concept for the rest of the long-term projection period. The extended baseline without macroeconomic feedback does not include any additional feedback after 2025.

The extended alternative fiscal scenario incorporates these assumptions: Certain policies that have been in place for a number of years but that are scheduled to change will be continued, some provisions of law that might be difficult to sustain for a long period will be modified, and federal revenues and certain categories of federal spending measured as shares of gross domestic product will be maintained at or near their historical averages over the long term.

In the illustrative scenarios with the 10-year deficit reduced by $2 trillion and by $4 trillion relative to the baseline, those amounts are the cumulative reductions in deficits excluding interest payments between 2016 and 2025.

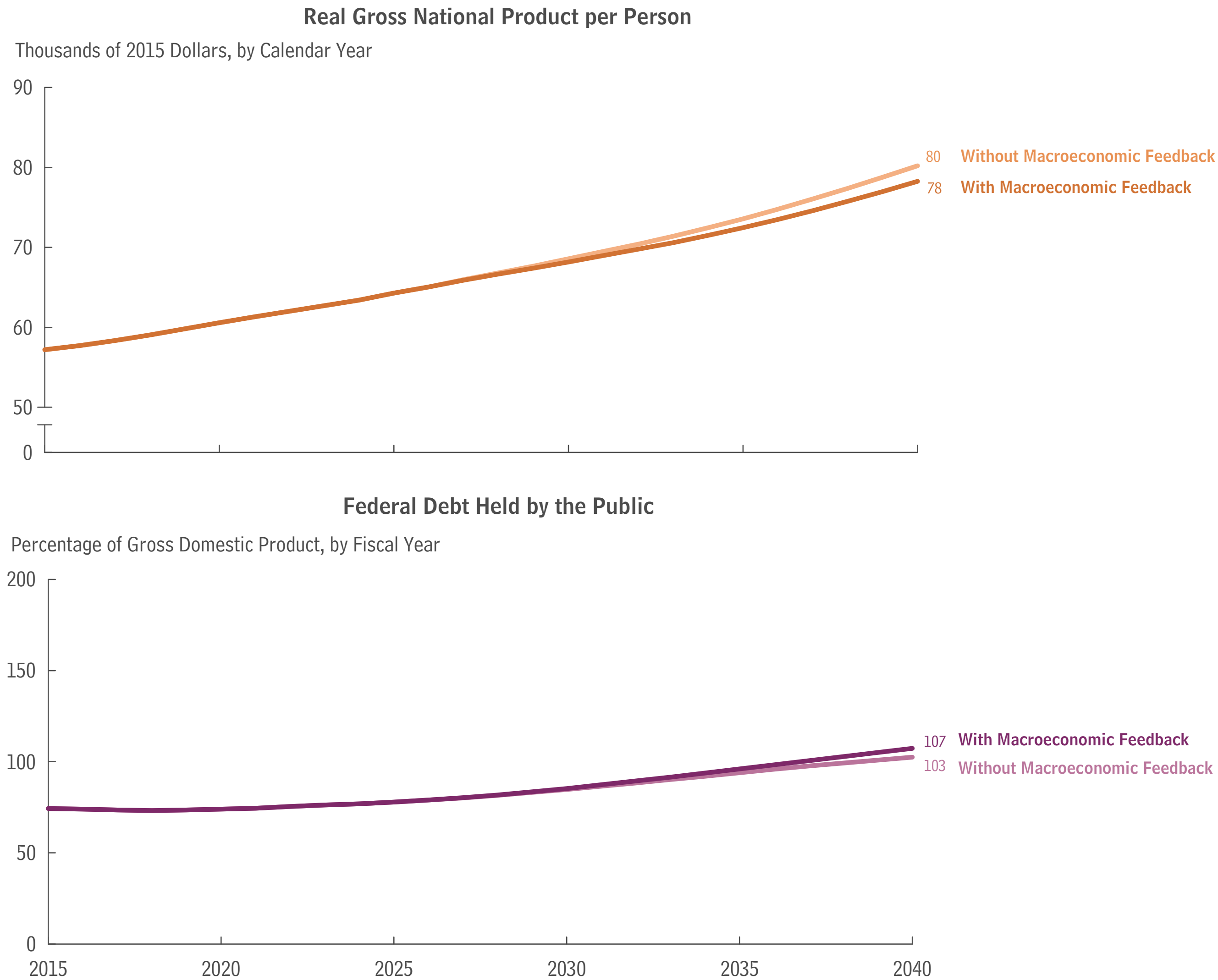
The results with macroeconomic feedback include the macroeconomic effects of the budget policies in the long run and the effects of that macroeconomic feedback on the budget. Those results are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

n.a. = not applicable; * = between -0.5 percent and zero.

Figure 6-2.

Effects of the Fiscal Policies in CBO's Extended Baseline

The fiscal policies in the extended baseline would further raise federal debt because they would reduce output and increase interest rates relative to the values for those factors without macroeconomic feedback—that is, in the economic benchmark that is intended to reflect stable economic conditions.



Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections, which include macroeconomic feedback, through 2025 and then extending the baseline concept for the rest of the long-term projection period. The extended baseline without macroeconomic feedback does not include any additional feedback after 2025.

Real (inflation-adjusted) gross national product differs from gross domestic product, the more common measure of the output of the economy, by including the income that U.S. residents earn abroad and excluding the income that nonresidents earn in this country.

The results with macroeconomic feedback include the macroeconomic effects of the budget policies and the effects of that macroeconomic feedback on the budget. Those results are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

percentage point. Outcomes could fall outside those ranges, which reflect only a few sources of uncertainty regarding the effects of fiscal policies on the economy. Significant uncertainty surrounds CBO's projections for other reasons as well. (That uncertainty is explored in Chapter 7.)

Budgetary Outcomes Under the Extended Baseline

The reduction in economic output and increase in interest rates (relative to the benchmark) caused by the fiscal policies in the extended baseline would make budgetary outcomes worse. Lower output implies less income and thus less tax revenue; it also implies that for any given amount of federal debt, the ratio of debt to GDP would be higher. Moreover, higher interest rates would mean larger interest payments on federal debt. In the other direction, lower output implies lower federal spending on health care and retirement programs.[15]

After incorporating those additional budgetary effects, CBO projects that debt held by the public in 2040 would be 107 percent of GDP; it is projected to be 103 percent under the extended baseline without macroeconomic feedback after 2025 (see Table 6-1 and Figure 6-2). In addition to the effects on output, income, and interest rates reported here, the high and rising federal debt projected under the extended baseline would impose significant constraints on policymakers and would raise the risk of a fiscal crisis.

Long-Term Effects of an Alternative Fiscal Scenario

Under the extended alternative fiscal scenario, certain policies now in place that are scheduled to change under current law are assumed to continue, some provisions of law that might be difficult to sustain for a long period are assumed to be modified, and federal revenues and certain categories of federal spending measured as shares of GDP are assumed to be maintained at or near historical averages. Thus, the scenario incorporates changes to those current policies that are reflected in the extended baseline but that some analysts consider difficult to maintain.

Under the extended alternative fiscal scenario, deficits would be substantially larger than they are projected to be in the extended baseline, and marginal tax rates on labor income and capital income would be lower. In addition, transfers to working-age people would be larger, and federal investment would be higher. Taken together, those differences would cause output to be lower and interest rates to be higher in the long run than under the extended baseline. Those macroeconomic effects, in turn, would further increase the gap between deficits and debt in this scenario and those in the extended baseline.

Fiscal Policies in the Extended Alternative Fiscal Scenario

Under the extended alternative fiscal scenario, deficits excluding interest payments would be larger than they are projected to be in the extended baseline by about \$2 trillion through 2025 and by increasing amounts in subsequent years.[16] Deficits would be larger under this scenario than under the extended baseline because noninterest spending would be higher and revenues lower (see Table 6-1).

Noninterest spending under this scenario would be 0.5 percent of GDP higher in 2025 and roughly 4 percent of GDP higher in 2040 than in the extended baseline. Those differences stem from two assumptions about the policies underlying the scenario that differ from those underlying the extended baseline:

- The automatic reductions in spending in 2016 and later that are required by the Budget Control Act of 2011 as amended would not occur—although the original caps on discretionary appropriations in the 2011 law would remain in place; and

15. In this analysis (as well as the analysis in Chapter 7), decreases in GDP stemming from macroeconomic feedback are estimated to reduce revenues (given current tax law), spending for Social Security (because lower earnings result in smaller benefits), and federal spending for health care programs (according to CBO's standard approach to projecting long-term cost growth, which is described in Chapter 2). However, CBO projects that other federal noninterest spending would remain at the amounts projected in the extended baseline even if GDP deviated from that baseline.

16. For additional detail on the policies underlying the alternative fiscal scenario, see Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), www.cbo.gov/publication/49892. In contrast to the estimates of the budgetary effects of those policies that CBO published in that earlier report, the estimates shown in Table 6-1 in this report incorporate macroeconomic feedback.

- Federal noninterest spending—apart from that for Social Security, the major health care programs (net of offsetting receipts), and certain refundable tax credits—as a percentage of GDP would rise after 2025 to its average during the past two decades rather than fall significantly below that level, as it does in the extended baseline.

Eliminating the Budget Control Act's automatic spending reductions and raising projected spending for a broad set of programs after 2025 would increase transfers to working-age people. Those policy changes would also increase discretionary spending and, consequently, federal investment, CBO projects.

Revenues under the extended alternative fiscal scenario would be 0.3 percent of GDP lower in 2025 and roughly 1 percent of GDP lower in 2040 than they are projected to be under the extended baseline. Overall, revenues as a share of GDP under the extended alternative fiscal scenario would remain flat after 2025 rather than rise as they do in the extended baseline. In the latter, revenues are projected to grow over time as a percentage of GDP largely for two reasons: Rising real income would push a greater share of income into higher tax brackets, and certain tax increases enacted in the Affordable Care Act would, to a lesser extent, generate increasing amounts of revenue relative to the size of the economy. Historically, however, federal revenues as a percentage of GDP have not trended upward; they have fluctuated with no evident trend during the past few decades.

The path of revenues in the extended alternative fiscal scenario shows what would happen if policymakers extended expiring tax provisions over the next decade and then made other changes to the law to keep revenues measured as a percentage of GDP close to their historical average. In particular, CBO incorporated the following two assumptions in the extended alternative fiscal scenario that differ from those underlying the extended baseline:

- About 70 expiring tax provisions, including one that allows businesses to deduct 50 percent of new investments in equipment immediately, will be extended through 2025; and

- After 2025, revenues will equal 18 percent of GDP, which is the level projected for 2025 given that assumption about expiring tax provisions and which is slightly higher than the average of 17.4 percent over the past 50 years.

Output and Interest Rates Under the Extended Alternative Fiscal Scenario

The substantially larger debt under the extended alternative fiscal scenario than under the extended baseline would reduce output and income below the projections in that baseline because of the additional crowding out of capital investment. In addition, the larger transfers to working-age people would reduce the supply of labor. However, the lower marginal tax rates on labor and capital income and the additional federal investment would boost output above the level projected for the extended baseline.

On balance, in CBO's assessment, output would be lower and interest rates would be higher under the extended alternative fiscal scenario than they would be under the extended baseline with macroeconomic feedback. In its central estimates, CBO projects that real GNP would be 0.6 percent lower in 2025 and about 5 percent lower in 2040; according to CBO's ranges of likely values for key variables, the reduction in real GNP would range from 0.3 percent to 1 percent in 2025 and from about 2 percent to about 8 percent in 2040 (see Table 6-2). However, even with the negative impact of the fiscal policies that are assumed under the alternative scenario, CBO projects that real GNP per person would be considerably higher in 2040 than in 2015 because of continued growth in productivity. Interest rates in 2040 would be about three-quarters of a percentage point higher under the alternative scenario than under the extended baseline, according to CBO's central estimate.

Budgetary Outcomes Under the Extended Alternative Fiscal Scenario

Budgetary outcomes under the extended alternative fiscal scenario would be worsened by the economic changes that resulted from the fiscal policies included in it. With the effects of lower output and higher interest rates incorporated, federal debt held by the public under the extended alternative fiscal scenario would reach 175 percent of GDP in 2040, according to CBO's central estimate; it is projected to be 107 percent of GDP under the extended baseline with macroeconomic feedback (see Figure 6-3). Thus, debt would be much higher and would rise much more rapidly than under the extended baseline.

In addition to having the effects on output, income, and interest rates reported here, the alternative fiscal scenario would also bring about many of the other consequences associated with high and rising federal debt that are

Table 6-2.

Long-Run Effects on Real GNP of the Fiscal Policies in Various Budget Scenarios

Percentage Difference From Level in the Extended Baseline With Macroeconomic Feedback

	2025	2040
Extended Alternative Fiscal Scenario (With 10-Year Deficit Increased by About $2 Trillion)		
Central estimate	-0.6	-5
Range	-1.0 to -0.3	-8 to -2
Illustrative Scenario With 10-Year Deficit Reduced by $2 Trillion		
Central estimate	0.6	3
Range	0.3 to 1.0	1 to 4
Illustrative Scenario With 10-Year Deficit Reduced by $4 Trillion		
Central estimate	1.2	5
Range	0.6 to 1.9	2 to 8

Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The extended alternative fiscal scenario incorporates these assumptions: Certain policies that have been in place for a number of years but that are scheduled to change will be continued, some provisions of law that might be difficult to sustain for a long period will be modified, and federal revenues and certain categories of federal spending measured as shares of gross domestic product will be maintained at or near their historical averages over the long term.

In the illustrative scenarios with the 10-year deficit reduced by $2 trillion and by $4 trillion relative to the baseline, those amounts are the cumulative reductions in deficits excluding interest payments between 2016 and 2025.

Real (inflation-adjusted) gross national product (GNP) differs from gross domestic product, the more common measure of the output of the economy, by including the income that U.S. residents earn abroad and excluding the income that nonresidents earn in this country.

The central estimates and ranges reflect alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

discussed above, and they would be especially acute under this scenario because the debt would be so high and would rise so rapidly. Such a path for debt would impose considerable constraints on policymakers and would significantly raise the risk of a fiscal crisis—and it would ultimately be unsustainable.

Long-Term Effects of Two Illustrative Scenarios With Smaller Deficits

CBO also projected economic developments during the coming decade under two illustrative budgetary paths that would gradually decrease deficits through unspecified increases in tax revenue, cuts in spending, or some combination of the two.[17] In the long run, the reduced federal deficits and debt under those scenarios would cause output and income to be higher and the ratio of federal debt to GDP to be lower than they would be under the extended baseline.

Fiscal Policies in the Two Illustrative Scenarios

In the two illustrative scenarios, CBO assumed that total deficits excluding interest payments between 2015 and 2025 would be $2 trillion or $4 trillion lower than what they are projected to be under current law. The reduction in the deficit relative to the extended baseline would be comparatively small in 2016 but would increase steadily through 2025; at that point, the reduction in the deficit excluding interest payments would be $360 billion, or nearly 1½ percent of GDP, under the first scenario and $720 billion, or over 2½ percent of GDP, under the second. In each subsequent year, the reduction, measured as a percentage of GDP, would equal the 2025 reduction.

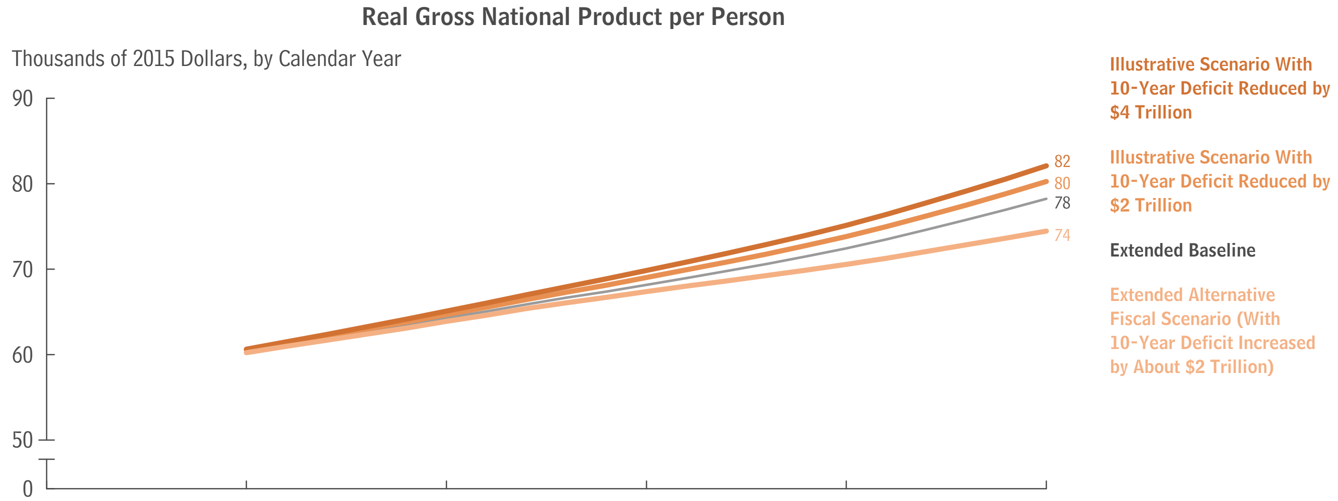
For the sake of simplicity and to avoid any presumption about which policies might be chosen to reduce the deficit, CBO analyzed those illustrative scenarios without

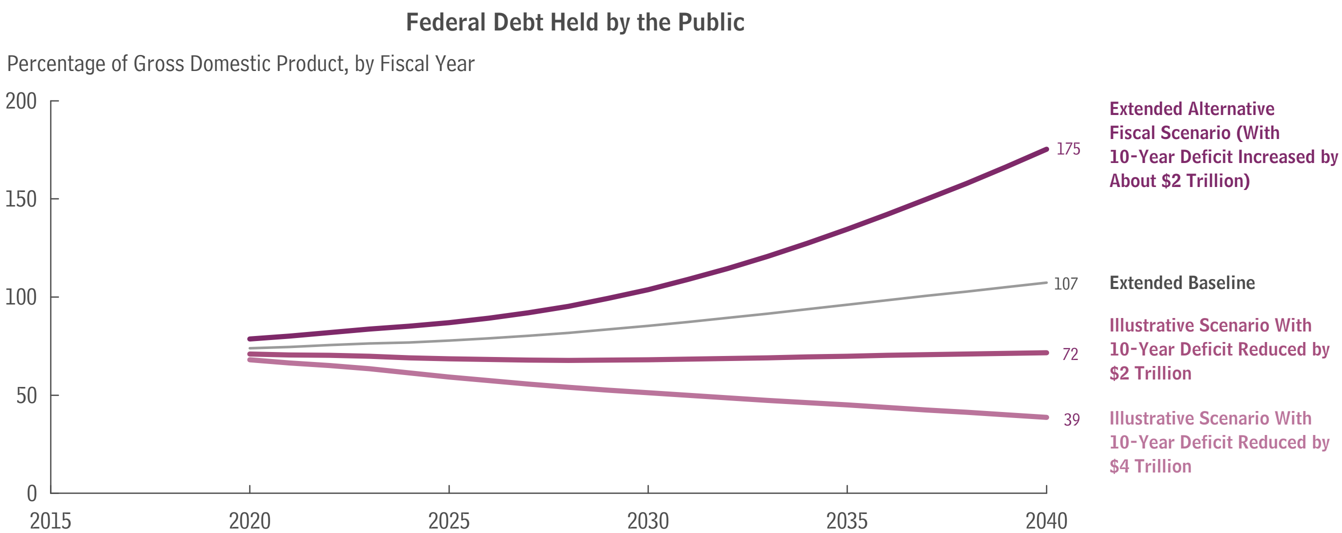
17. Congressional Budget Office, *Budgetary and Economic Outcomes Under Paths for Federal Revenues and Noninterest Spending Specified by Chairman Price* (March 2015), www.cbo.gov/publication/49977.

Figure 6-3.

Long-Run Effects of the Fiscal Policies in CBO's Extended Baseline, Extended Alternative Fiscal Scenario, and Illustrative Scenarios With Smaller Deficits

The effects of lower economic output and higher interest rates under the extended alternative fiscal scenario would raise federal debt held by the public by increasing amounts over time. The two illustrative scenarios involving deficit reductions would have the opposite effects.





Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The extended alternative fiscal scenario incorporates these assumptions: Certain policies that have been in place for a number of years but that are scheduled to change will be continued, some provisions of law that might be difficult to sustain for a long period will be modified, and federal revenues and certain categories of federal spending measured as shares of gross domestic product will be maintained at or near their historical averages over the long term.

In the illustrative scenarios with the 10-year deficit reduced by $2 trillion and by $4 trillion relative to the baseline, those amounts are the cumulative reductions in deficits excluding interest payments between 2016 and 2025.

The results shown here do not include the macroeconomic effects of the scenarios from 2015 to 2019. Short-run macroeconomic effects are discussed later in this chapter.

Real (inflation-adjusted) gross national product differs from gross domestic product, the more common measure of the output of the economy, by including the income that U.S. residents earn abroad and excluding the income that nonresidents earn in this country.

The results are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

specifying the tax and spending policies underlying them. As a result, the projected outcomes under the scenarios do not reflect any direct changes to incentives to work and save; in particular, marginal tax rates and transfers to working-age people are assumed to be the same as those under current law. Also, the contributions that government investment makes to future productivity and output are assumed to reflect their historical averages.

The estimated macroeconomic effects presented here therefore arise solely from the differences in deficits and debt. However, reducing budget deficits significantly below what they would be under current law without altering government investment or incentives to work and save would be very difficult. The overall economic impact of policies that lowered deficits would depend not only on the way they changed federal borrowing but also on the way they affected government investment and incentives to work and save.

Output and Interest Rates Under the Two Illustrative Scenarios

Under the scenario involving a $2 trillion reduction in deficits in the first decade, real GNP would be higher than it would be under the extended baseline with macroeconomic feedback by 0.6 percent in 2025 and by about 3 percent in 2040, according to CBO's central estimates (see Table 6-2). According to CBO's ranges of likely values for key variables, the increase in real GNP would probably be between 0.3 percent and 1 percent in 2025 and between about 1 percent and about 4 percent in 2040. Interest rates in 2040 would be about one-third of a percentage point lower under that scenario than under the extended baseline, according to CBO's central estimate.

Under the scenario involving a $4 trillion reduction in deficits in the first decade, real GNP would be higher than it would be under the extended baseline with macroeconomic feedback by 1.2 percent in 2025 and by about 5 percent in 2040, by CBO's central estimates. According to CBO's ranges of likely values for key variables, the increase in real GNP would probably be between 0.6 percent and 1.9 percent in 2025 and between about 2 percent and about 8 percent in 2040. Interest rates in 2040 would be about two-thirds of a percentage point lower under that scenario than under the extended baseline, according to CBO's central estimate.

CBO projects that under either illustrative scenario, real GNP per person would be substantially higher in 2040 than in 2015.

Budgetary Outcomes Under the Two Illustrative Scenarios

The higher output and lower interest rates under the illustrative scenarios would improve budgetary outcomes in the long run. For the scenario with $2 trillion of deficit reduction in the first decade, federal debt held by the public in 2040 would stand at 72 percent of GDP, according to CBO's central estimates, slightly less than the 74 percent of GDP that debt amounted to at the end of 2014 and 35 percentage points lower than it is projected to be under the extended baseline with macroeconomic feedback (see Table 6-1 on page 81 and Figure 6-3). For the scenario with $4 trillion of deficit reduction in the first decade, federal debt held by the public would fall to 39 percent of GDP in 2040, 68 percentage points lower than it is projected to be under the extended baseline with macroeconomic feedback; such debt was 35 percent of GDP in 2007 and averaged 38 percent over the past 50 years.

The scenario with the $2 trillion deficit reduction would also limit the other consequences of high and rising federal debt that were discussed above. Because debt as a percentage of GDP would be fairly steady—albeit high by historical standards—the constraints on policymakers and the risk of a fiscal crisis would be smaller than they would be under the extended baseline scenario, in which the debt-to-GDP ratio is projected to increase substantially. The scenario with the $4 trillion deficit reduction would reduce the other consequences of high debt much more sharply. With debt returning to about the percentage of GDP that it averaged over the past 50 years, the constraints on policymakers and the risk of a fiscal crisis would be greatly diminished compared with what they would be under the extended baseline.

Short-Term Macroeconomic Effects of the Three Additional Fiscal Scenarios

The various fiscal policies whose long-term macroeconomic effects have been analyzed in this chapter would have short-term effects as well. In the short term, policies that increased federal spending or cut taxes (and thus boosted budget deficits) would generally increase the demand for goods and services, thereby raising output and employment above what they would be in the absence of those policies. Similarly, policies that decreased federal

Table 6-3.

Short-Run Effects of the Fiscal Policies in Various Budget Scenarios

	Inflation-Adjusted Gross Domesic Product (Percentage difference)		Full-Time-Equivalent Employment (Difference in millions)	
	2016	2017	2016	2017
Alternative Fiscal Scenario				
Central estimate	0.6	0.3	0.7	0.5
Range	0.1 to 1.0	0 to 0.6	0.2 to 1.3	0.1 to 0.9
Illustrative Scenario With 10-Year Deficit Reduced by $2 Trillion				
Central estimate	-0.2	-0.2	-0.2	-0.2
Range	-0.3 to -0.1	-0.3 to 0	-0.3 to -0.1	-0.4 to -0.1
Illustrative Scenario With 10-Year Deficit Reduced by $4 Trillion				
Central estimate	-0.3	-0.3	-0.4	-0.5
Range	-0.6 to -0.1	-0.6 to -0.1	-0.7 to -0.1	-0.9 to -0.1

Source: Congressional Budget Office.

Notes: Figures reflect the differences in the levels between outcomes under a scenario and outcomes under CBO's baseline, which incorporates an assumption that current laws generally remain unchanged.

The alternative fiscal scenario incorporates these assumptions: Certain policies that have been in place for a number of years but that are scheduled to change will be continued, some provisions of law that might be difficult to sustain for a long period will be modified, and federal revenues and certain categories of federal spending measured as shares of gross domestic product will be maintained at or near their historical averages over the long term.

In the illustrative scenarios with the 10-year deficit reduced by $2 trillion and by $4 trillion relative to the baseline, those amounts are the cumulative reductions in deficits excluding interest payments between 2016 and 2025.

The central estimates and ranges reflect alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

spending or raised taxes (and thus decreased budget deficits) would generally reduce demand, thereby lowering output and employment below what they would be otherwise. Those effects are stronger when short-term interest rates are near zero and output is below its potential (maximum sustainable) level, in part because under those conditions the Federal Reserve is unlikely to adjust short-term interest rates to try to offset the effects of changes in federal spending and taxes.

Effects of the Extended Alternative Fiscal Scenario

The increase in deficits under the extended alternative fiscal scenario would cause real GDP to be higher in the next few years than it would be under current law, CBO estimates. The policies incorporated in that scenario would raise the demand for goods and services in the short run, increasing real GDP above what is projected under current law by 0.6 percent in 2016 and 0.3 percent in 2017, according to CBO's central estimates (see Table 6-3).[18] The policies would probably also increase real GDP for a few years after 2017, but CBO has not estimated the effects for those years. According to CBO's ranges of likely outcomes for key variables, in 2016, real GDP would probably be between 0.1 percent and 1 percent higher, and in 2017, it would probably be equal to or be as much as 0.6 percent higher, than what is projected under current law.[19]

18. CBO's estimates of the short-term effects of the extended alternative fiscal scenario and the two illustrative scenarios on real GDP are very similar to the agency's estimates of the effects on real GNP. This analysis focuses on GDP to be consistent with CBO's other analyses of the short-term impact of fiscal policies. The estimates reported here refer to averages during the calendar years referenced; some of CBO's other analyses of the short-term impact of fiscal policies have focused on effects during particular quarters of the year.

19. For a discussion of CBO's analytical approach to estimating the short-term economic effects of fiscal policy, see Felix Reichling and Charles Whalen, *Assessing the Short-Term Effects on Output of Changes in Federal Fiscal Policies*, Working Paper 2012-08 (Congressional Budget Office, May 2012), www.cbo.gov/publication/43278; and Congressional Budget Office, *How CBO Analyzes the Effects of Changes in Federal Fiscal Policies on the Economy* (November 2014), www.cbo.gov/publication/49494.

To produce that additional output, businesses would hire more workers. According to CBO's central estimates, the policies in the alternative fiscal scenario would increase the number of full-time-equivalent employees above the number projected under current law by 0.7 million in 2016 and by 0.5 million in 2017.

Effects of the Two Scenarios With Smaller Deficits

Under the two illustrative scenarios that reduce deficits, real GDP would be lower in the next several years than projected under current law, CBO estimates. Because the agency did not specify the fiscal policies underlying those two scenarios, the estimated macroeconomic effects arise solely from the differences in overall deficits.

In the $2 trillion scenario, the reductions in the deficit excluding interest costs amount to $40 billion in 2016 and $76 billion in 2017. In the $4 trillion scenario, those reductions amount to $80 billion in 2016 and $151 billion in 2017. Under the first scenario, real GDP in 2016 would be 0.2 percent lower than it is projected to be under current law (or between 0.1 percent and 0.3 percent lower, according to CBO's ranges of likely outcomes for key variables); in 2017, real GDP would again be 0.2 percent lower (or, according to CBO's ranges of likely outcomes, it would be equal to or be as much as 0.3 percent lower than what it is projected to be under current law).[20] Under the second scenario, real GDP would be 0.3 percent lower than it is projected to be under current law (or between 0.1 percent and 0.6 percent lower, according to CBO's ranges of likely outcomes for key variables) in both 2016 and 2017. By CBO's estimates, the policies would continue to reduce real GDP below what it would be under current law for a few years after 2017, but CBO has not estimated the effects for those years.

Because businesses would produce less, they would hire fewer workers. According to CBO's central estimates, the number of full-time-equivalent employees under the first scenario would be 0.2 million smaller both in 2016 and 2017 than under current law; under the second scenario, there would be 0.4 million fewer full-time-equivalent employees in 2016 and 0.5 million fewer in 2017 than under current law.

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20. CBO's central estimates here reflect the agency's assumption that in the two illustrative scenarios, each one-dollar change in budget deficits excluding interest payments relative to those under current law would, in the short term and under current economic conditions, change output cumulatively by one dollar over several quarters. That dollar-for-dollar response lies within the ranges of estimated effects on GDP of many policies that CBO examined in analyzing the macroeconomic effects of the American Recovery and Reinvestment Act of 2009. CBO's range of likely outcomes implies that each one-dollar change in deficits excluding interest payments would, in the short term and under current economic conditions, change output cumulatively by between $0.33 and $1.67. For a similar approach, see Congressional Budget Office, *Budgetary and Economic Outcomes Under Paths for Federal Revenues and Noninterest Spending Specified by Chairman Price, March 2015* (March 2015), www.cbo.gov/publication/49977.

CHAPTER

7

The Uncertainty of Long-Term Budget Projections

Budget projections are inherently uncertain. The projections in this report generally reflect current law and estimates of future economic conditions and demographic trends. If future spending and tax policies differ from what is prescribed in current law, budgetary outcomes will differ from those in the Congressional Budget Office's extended baseline, as the preceding chapter shows. But even if policies do not change, the economy, demographics, and other factors will undoubtedly differ from what CBO projects, and those differences will in turn cause budgetary outcomes to deviate from the projections in this report. Those variations could be within the ranges of experience observed in the relevant historical data—which, for the factors that CBO analyzes, cover roughly the past 50 to 70 years—or they might deviate from historical experience. Moreover, there could be significant budgetary effects from channels that CBO does not currently take into account in its estimates.

To illustrate some of the uncertainty about long-term budgetary outcomes, CBO constructed alternative projections showing what would happen to the budget if various underlying factors differed from the values that are used in most of this report. The agency focused on four factors that are among the most fundamental and yet most uncertain inputs into the agency's long-term economic and budget projections. Specifically, CBO quantified the consequences of alternative paths for the following variables:

- The decline in mortality rates;
- The growth rate of total factor productivity (that is, the efficiency with which labor and capital are used to produce goods and services; it is often referred to in this chapter simply as productivity);
- Interest rates on federal debt held by the public; and
- The growth rate of federal spending per beneficiary for Medicare and Medicaid.

Different paths for those four factors would affect the budget in various ways. For example, lower-than-projected mortality rates would mean longer average life spans, which would increase the number of people who received benefits from such programs as Social Security, Medicare, and Medicaid; lower mortality rates would also boost the size of the labor force and thereby add to tax revenues (but by less than the increase in benefit costs). Faster growth in spending per beneficiary for Medicare and Medicaid would boost outlays for those two programs. Either of those changes would increase deficits and debt—which would lead to lower output and higher interest rates, macroeconomic feedback that would further worsen the budget outlook.[1] By contrast, faster growth in productivity or lower interest rates on federal debt held by the public would reduce deficits and debt—the former, by raising output and increasing revenues, and the latter, by lowering the government's interest payments.

The projected budgetary outcomes under the alternative paths differ widely. The simulated variations in productivity, interest rates, and Medicare and Medicaid spending have large effects on the budget within 25 years, whereas the simulated variation in mortality rates does not. When only one of the factors is changed, CBO's projections of federal debt held by the public in 2040 range from

1. In cases in which projected budget deficits are larger than those in the extended baseline, output would be lower, leading to lower revenues (under current tax law), less spending on Social Security (because lower earnings result in smaller benefits), and less federal spending on Medicare and Medicaid (according to CBO's standard approach to projecting long-term cost growth, which is described in Chapter 2). However, CBO assumes that other federal noninterest spending would remain at the amounts in the extended baseline even if output deviated from the amounts underlying that baseline.

89 percent of gross domestic product (GDP) to 130 percent, whereas it is projected to be 107 percent under the extended baseline with macroeconomic feedback.[2] When all four factors are changed at once, projections of federal debt in 2040 range from 76 percent to 144 percent of GDP. Those projected levels of debt are all high by historical standards, and a number of them exceed the peak of 106 percent of GDP that the United States reached in 1946.

The four factors listed above are not the only ones that could differ from CBO's expectations and, in turn, affect the agency's budget projections. For example, an increase in the birth rate or in labor force participation could boost the growth of the labor force and thus raise tax revenues. Similarly, decisions by states about how much they spend on Medicaid could increase or decrease federal spending relative to CBO's projections.

Large disruptions in the economy could have significant effects on the budget that are not quantified in this analysis. The analytic approach that CBO used for this long-term analysis focuses on projecting average outcomes. An economic depression, unexpectedly large losses on federal financial obligations, a large-scale military conflict, the development of a previously underused natural resource, or a major catastrophe—to give just a few examples—could create conditions in the next 25 years that are substantially better or worse than those that produced the historical data on which the analysis is based.

Policymakers could address the uncertainty associated with long-term budget projections in various ways. For instance, they might design policies that partly insulated the federal budget from some unanticipated events; however, such policies could have unwanted consequences, such as shifting risk to individuals. Another possibility is that policymakers might aim for a smaller amount of federal debt to provide a buffer against the budgetary impact of adverse surprises and allow for more flexibility in responding to unexpected crises in the future.

2. As Chapter 6 explains, that version of the extended baseline incorporates the macroeconomic effects of the fiscal policies in the extended baseline and, in turn, the feedback of those effects to the federal budget. As a result, the economic and budget projections in the extended baseline with macroeconomic feedback differ somewhat from those presented in the first five chapters of this report.

Long-Term Budgetary Effects of Changes in Mortality, Productivity, Interest Rates on Federal Debt, and Federal Spending on Medicare and Medicaid

Budgetary outcomes could differ from CBO's projections if mortality rates, the growth rate of productivity, interest rates on government debt, or the growth of federal spending on Medicare and Medicaid diverged from the paths that underlie the extended baseline projections in this report. Unexpected changes in mortality rates would gradually lead to changes in spending for Social Security, Medicare, and Medicaid. Changes in productivity would lead to changes in economic output, which would affect both revenues and spending. Changes in the interest rates on federal debt would affect the amount of interest paid by the government. And changes in the growth rate of federal health care spending, one of the largest components of the budget, would have significant implications for overall federal spending.

For CBO's alternative projections, the ranges of variation for those four factors were based on the historical variation in their 25-year averages as well as on consideration of possible future developments, which together offer a guide (though admittedly an imperfect one) to the amount of uncertainty that surrounds projections of those factors over the next 25 years. To better capture overall uncertainty, CBO also constructed two projections in which all four factors simultaneously varied from their values under the extended baseline. In one of those cases, all of the factors varied in ways that increased the amount of federal debt; in the other, they varied in ways that reduced the amount of the debt.[3]

Under the projections of those four factors that are used in CBO's extended baseline, federal debt held by the

3. Another approach to quantifying the uncertainty of budget projections would be to create a distribution of outcomes from a large number of simulations in which such factors as productivity growth, interest rates, and the rate of increase of health care costs varied. CBO generally uses that approach in its reports on the financial outlook for the Social Security trust funds. See Congressional Budget Office, *CBO's 2014 Long-Term Projections for Social Security: Additional Information* (December 2014), www.cbo.gov/publication/49795, and *Quantifying Uncertainty in the Analysis of Long-Term Social Security Projections* (November 2005), www.cbo.gov/publication/17472. However, determining the appropriate variation in those factors and estimating the distribution of outcomes for the federal budget as a whole requires additional modeling tools that CBO has not yet developed.

public would equal 107 percent of GDP in 2040 (including macroeconomic feedback). Alternative projections of the factors would lead to the following outcomes:

- If mortality rates declined 0.5 percentage points per year more slowly or more quickly than they do in CBO's extended baseline, federal debt held by the public in 2040 would be 106 percent of GDP or 109 percent of GDP, respectively.

- If productivity grew 0.5 percentage points per year more quickly or more slowly than it does in CBO's extended baseline, federal debt held by the public in 2040 would be 91 percent of GDP or 125 percent of GDP, respectively.

- If the average interest rate on government debt was 0.75 percentage points lower or higher than that in CBO's extended baseline, federal debt held by the public in 2040 would be 89 percent of GDP or 130 percent of GDP, respectively.

- If spending per beneficiary for Medicare and Medicaid grew 0.75 percentage points per year more slowly or more quickly than it does in CBO's extended baseline, federal debt held by the public in 2040 would be 89 percent of GDP or 129 percent of GDP, respectively.

- If all four factors deviated from their baseline values in ways that reduced deficits but did so by only 60 percent as much as in the cases specified above, federal debt held by the public in 2040 would be 76 percent of GDP; if all four factors deviated in ways that increased deficits but did so by only 60 percent as much as in the cases specified above, federal debt held by the public would be 144 percent of GDP.[4]

Mortality

Mortality rates measure the number of deaths in a given year per thousand people in a population. Faster improvement in age-specific mortality rates would mean people of all ages would be expected to live longer, which would increase the number of people who received benefits from—and thus outlays for—Social Security, Medicare, Medicaid, and certain other mandatory spending programs.[5] Changes in mortality rates would also affect the budget by changing the size of the labor force and thereby changing tax revenues; specifically, CBO projects that the average person would work three more months for each additional year of life expectancy, slightly increasing overall labor force participation (see Appendix A).

Mortality rates have declined steadily over the past half century, and CBO expects that decline to continue. Just how steep that future decline will be, however, is quite uncertain. CBO therefore constructed projections covering a 1 percentage-point range (see Figure 7-1). The agency arrived at that range by comparing the average annual change in mortality rates for the 45 25-year periods that began each year from 1942 (the 1942–1966 period) to 1986 (the 1986–2010 period). The average annual change varied by about the same amount—roughly 1 percentage point—for men and for women.[6] Applying that 1 percentage-point range around the 1.2 percent rate used in CBO's extended baseline resulted in rates of decline ranging from 0.7 percent per year to 1.7 percent per year. If the rate of decline was within that range, life expectancy for 65-year-olds would be between 85.8 years and 87.9 years in 2040, whereas under the extended baseline, it would be 86.8 years in 2040; it is 84.5 years today.

Those alternative projections for the decline in mortality rates would lead to the following alternative budget projections:

4. According to CBO's analysis of the historical data, joint variation to that extent yields outcomes for federal debt that are about as likely as the outcomes when an individual factor changes to the full extent of its range.

5. If an increase in life expectancy was accompanied by a gain in the average number of years that elderly people spend in good health, Medicare and Medicaid spending for elderly beneficiaries would not necessarily increase with the growth in the elderly population.

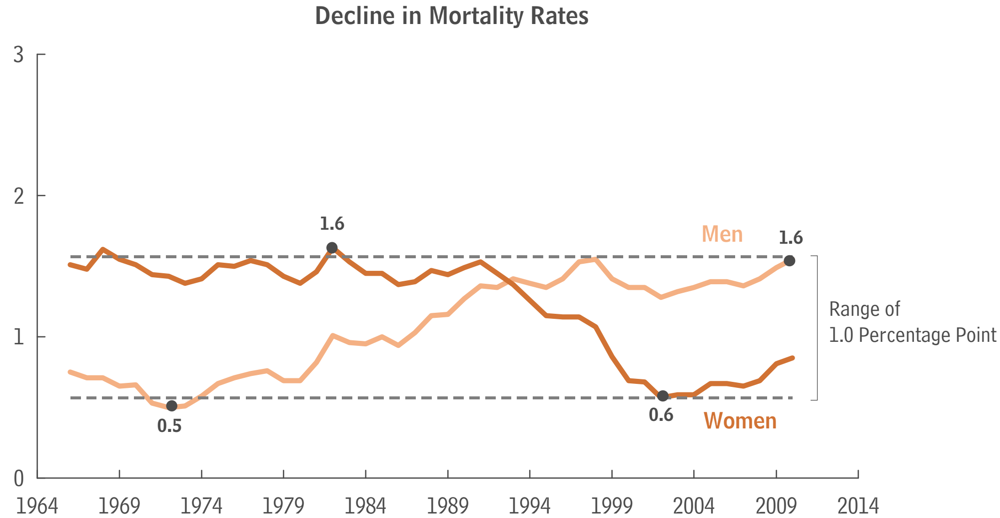
6. The rate of decline in *aggregate* mortality—that is, the rate for men and women combined—exhibited substantially less variation than the decline in mortality rates for men and women separately. From 1950 through 1980, the mortality rate for women declined faster than the mortality rate for men; after 1980, the mortality rate for men declined faster than the mortality rate for women. (That difference resulted in part from changes in smoking rates over time for men and for women.) In CBO's assessment, the variations in the declines of the mortality rates of men and women considered separately are more representative of the uncertainty in mortality rates over the next 25 years.

Figure 7-1.

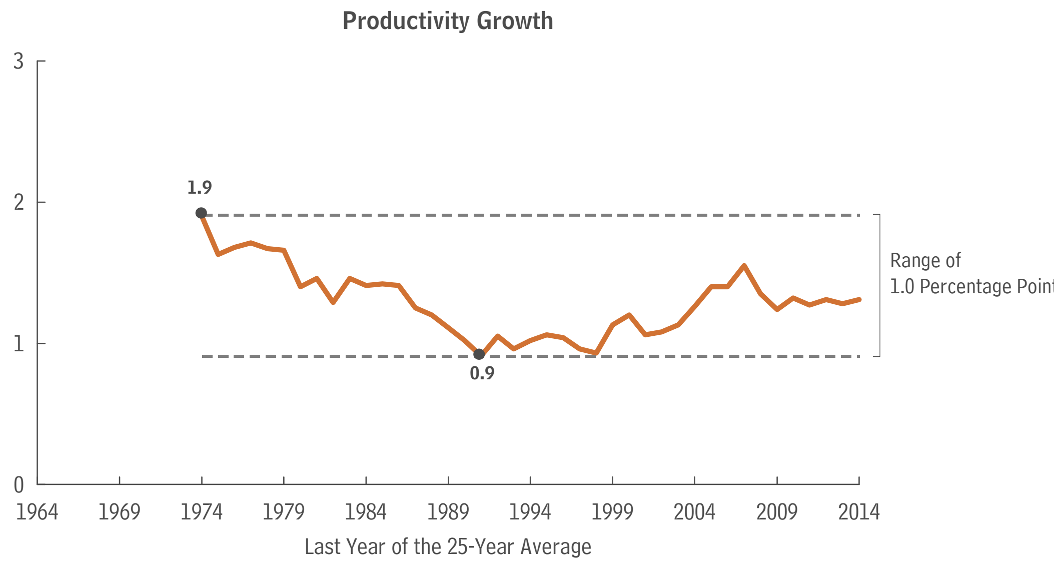
The 25-Year Averages and Ranges CBO Used for Four Factors Affecting Budgetary Outcomes

Percentage Points

Labeled values indicate the highest and lowest 25-year averages for each series.



The average productivity growth of 1.9 percent from 1949 to 1974 was greater than the 25-year averages since then.



Sources: Congressional Budget Office; Social Security Administration; Federal Reserve.

Notes: The 25-year average for a given year is the average of the data value for that year and the values for the preceding 24 years. For example, the 25-year average for productivity growth in 1974 is the average of the growth of productivity from 1949 through 1974.

The decline in the mortality rate is the decline in the number of deaths per thousand people in a population in a given year.

Productivity growth is the growth in total factor productivity, which is the efficiency with which labor and capital are used to produce goods and services.

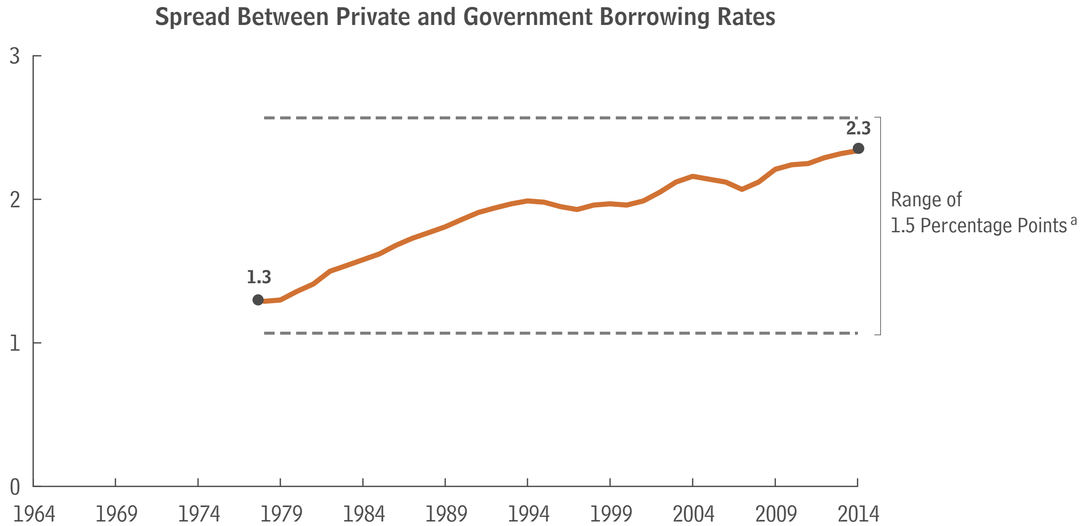
The spread between private and government borrowing rates is the difference between the interest rate on Baa-rated corporate bonds and on 10-year Treasury notes.

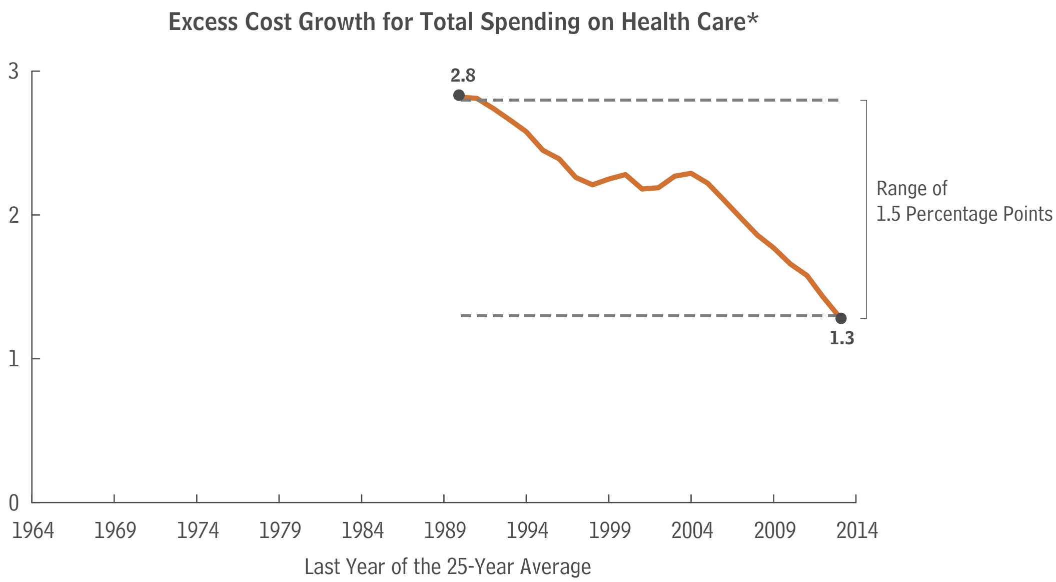
Continued

Figure 7-1. Continued

The 25-Year Averages and Ranges CBO Used for Four Factors Affecting Budgetary Outcomes

Percentage Points





Excess cost growth refers to the extent to which the annual growth rate of nominal health care spending per capita—adjusted for demographic characteristics of the relevant populations—outpaces the annual growth rate of potential (maximum sustainable) output per capita. The historical rates of excess cost growth are a weighted average of annual rates: Twice as much weight is placed on the latest year as on the earliest year.

Time periods reflect data availability.

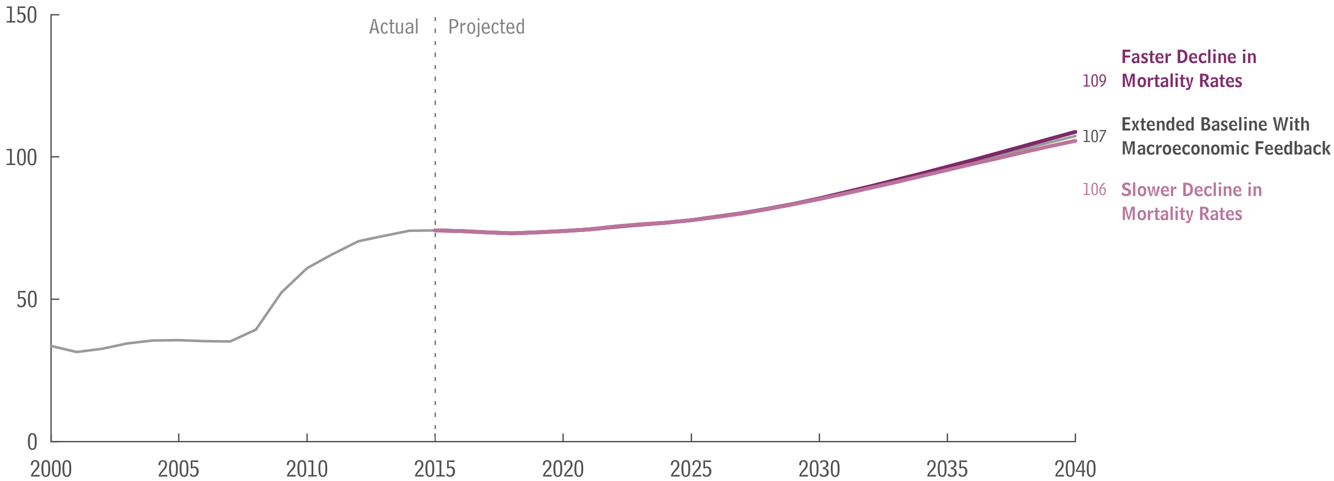
a. To account for various sources of uncertainty as well as for other factors that may not be fully represented by the particular measure of the spread used and the historical time period analyzed, CBO expanded the range of uncertainty used for this analysis from the 1.0 percentage point suggested by the historical data to 1.5 percentage points.

[* Panel heading corrected on July 1, 2015]

Figure 7-2.

Federal Debt Given Different Rates of Mortality Decline

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The faster decline in the mortality rates is 0.5 percentage points higher—and the slower decline in the mortality rates is 0.5 percentage points lower—than the annual decline of 1.2 percent used in the extended baseline with macroeconomic feedback.

Federal debt refers to debt held by the public. Estimates for the extended baseline with macroeconomic feedback are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

- If mortality rates declined by 0.7 percent a year—that is, 0.5 percentage points more slowly than the rate used in the extended baseline—outlays for Social Security, Medicare, and Medicaid would be lower. That would lead to less federal debt held by the public—specifically, debt would equal 106 percent of GDP in 2040 rather than the 107 percent that CBO projects under the extended baseline with macroeconomic feedback (see Figure 7-2). In addition, the estimated changes in spending or revenues needed to keep federal debt held by the public at its current level of 74 percent of GDP over the 25-year period—the fiscal gap—would be slightly smaller than CBO projects under the extended baseline, but they would round to the same 1.1 percent of GDP.[7] Although those differences are relatively small in 2040, they would grow substantially over time as the effect on mortality rates compounded and average life spans fell increasingly below those incorporated in the baseline.

- In contrast, if mortality rates declined by 1.7 percent a year, or 0.5 percentage points more quickly than in the extended baseline, outlays for the same three programs would be higher, resulting in federal debt held by the public that reached 109 percent of GDP in 2040. The 25-year fiscal gap would rise to 1.2 percent of GDP.

Productivity

Total factor productivity is an important determinant of economic output. Its growth stems from the introduction and spread of new technological approaches, from increases in workers' education and skill levels, and from

7. For a discussion of how CBO measures the fiscal gap, see Chapter 1. The estimates of the fiscal gap presented in this chapter, like those in Chapter 1, are calculated without macroeconomic feedback. It would not be informative to include the negative economic effects of rising debt (and their feedback to the budget) in the fiscal gap calculation because the fiscal gap shows the budgetary changes required to keep debt from rising in the first place; if those budgetary changes were made, the negative economic effects (and their feedback to the budget) would not occur.

the use of new processes that improve the efficiency of organizations.[8] CBO estimates that the growth of total factor productivity, which has averaged 1.4 percent per year since 1950, has accounted for over 40 percent of the increase in real (inflation-adjusted) nonfarm business output over that time. CBO's extended baseline incorporates the projection that such productivity will increase, on average, by 1.3 percent per year in the coming decades.

However, the growth rate of total factor productivity has often varied for extended periods. Periods of rapid growth have generally resulted from major technological innovations. For example, innovations in four critical areas—electricity generation, internal combustion engines, chemicals, and telecommunications—triggered a surge in productivity in the 1920s and 1930s. Another surge occurred in the 1950s and 1960s, spurred by the electrification of homes and workplaces, suburbanization, completion of the nation's highway system, and production of consumer appliances. The latest surge in productivity—a more modest one—began in the 1990s and is attributed to innovations involving computers and other types of information technology.[9] Productivity growth has been relatively weak since the 2007–2009 recession, largely because of the cyclical weakness in the economy that is expected to continue to dissipate over the next few years.

The future growth rate of productivity is quite uncertain. The nation could experience faster growth in productivity than is reflected in CBO's extended baseline, either steadily (from ongoing gains from, for example, integrating information technology into the economy) or in a burst (from a technological breakthrough, such as the development of a new source of energy). Conversely, the growth of productivity could be slower than in CBO's extended baseline if the rate of increase in workers' education levels declined or if technological innovation or the dispersion of previous technological innovations throughout the economy diminished. For example, although CBO projects that productivity growth will improve once the economy fully recovers, the 2007–2009 recession and slow recovery have weakened productivity for an extended period. If the continued weakness indicates that the effects of the recession will last longer than CBO projected, productivity growth over the longer term could be weaker than is reflected in the extended baseline.

A different growth rate for productivity would affect the federal budget by changing output and income and also, in CBO's assessment, by changing the interest rates paid by the federal government. Higher total factor productivity means that capital is more productive, which implies a higher rate of return from private capital investment, all else being equal. According to widely used economic models, if productivity grows faster, that rate of return remains higher over time. Because the federal government competes with private borrowers for investors' money, higher returns from private investment should push up interest rates paid by the federal government. Although empirical estimates of the relationship between productivity growth and interest rates vary, the theoretical relationship is clear enough for CBO to incorporate an effect on interest rates into this analysis.[10]

Average productivity growth during the 41 25-year periods beginning with the 1950–1974 period and ending with the 1990–2014 period varied by about 1 percentage point (see Figure 7-1 on page 94). CBO therefore projected economic and budgetary outcomes if total factor productivity grew by either 0.8 percent or 1.8 percent per year over the next 25 years—that is, 0.5 percentage points more slowly or more quickly than the 1.3 percent per year incorporated in the extended baseline.[11]

8. Total factor productivity is different from labor productivity, which measures the amount of goods and services that can be produced per hour of labor.

9. For further discussion, see Robert Shackleton, *Total Factor Productivity Growth in Historical Perspective*, Working Paper 2013-01 (Congressional Budget Office, March 2013), www.cbo.gov/publication/44002.

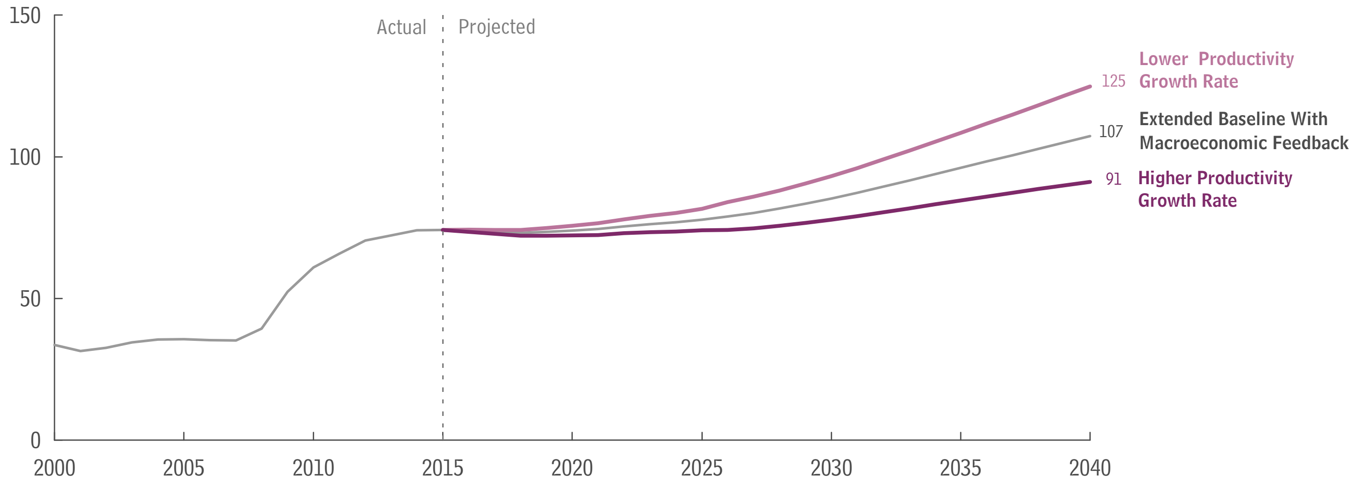
10. For example, in the Solow-type growth model that CBO used for this analysis, if productivity grew 0.5 percentage points more quickly than in the extended baseline with macroeconomic feedback, the average interest rate on federal debt held by the public in 2040 would be about 1 percentage point higher than the baseline value. For details of that model, see Congressional Budget Office, *CBO's Method for Estimating Potential Output: An Update* (August 2001), www.cbo.gov/publication/13250.

11. For another approach to measuring uncertainty in long-run projections of productivity growth, see Ulrich K. Müller and Mark W. Watson, *Measuring Uncertainty About Long-Run Predictions* (draft, Princeton University, September 2014), http://tinyurl.com/nl9bzws (PDF, 3 MB). Müller and Watson's approach yields a range of uncertainty around productivity growth that is similar in size to the range that CBO calculated.

Figure 7-3.

Federal Debt Given Different Rates of Productivity Growth

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The lower productivity growth rate is 0.5 percentage points lower—and the higher productivity growth rate is 0.5 percentage points higher—than the annual rate of 1.3 percent used in the extended baseline with macroeconomic feedback.

Federal debt refers to debt held by the public. Estimates for the extended baseline with macroeconomic feedback are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

Those alternative projections for total factor productivity growth would lead to the following alternative budget projections:

- If total factor productivity grew by 1.8 percent annually, 0.5 percentage points more quickly than in the baseline, then the greater GDP would result in more revenue, smaller budget deficits, and less federal debt. Federal debt held by the public would be 91 percent of GDP in 2040 rather than the 107 percent that CBO projects under the extended baseline with macroeconomic feedback (see Figure 7-3). The 25-year fiscal gap would be 0.8 percent of GDP rather than the 1.1 percent that CBO projects under the extended baseline.

- If productivity grew by 0.8 percent annually, 0.5 percentage points more slowly than in the baseline, the slower economic growth would result in less revenue, bigger budget deficits, and more debt. That debt would be 125 percent of GDP in 2040. The 25-year fiscal gap would rise to 1.5 percent of GDP.

Faster or slower productivity growth could also affect the budget in ways that are not accounted for in this analysis—for example, by changing the shares of the nation's income received by workers (as wages and salaries, for instance) and by the owners of capital (as corporate profits, for instance). In recent years, technological change appears to have affected productivity in ways that put downward pressure on labor's share (for example, by expanding options for using capital in place of labor), a trend that some economists believe will be long-lasting.[12] In addition, some types of ongoing technological change appear to be intensifying wage inequality.[13] Such shifts in

12. For further discussion, see Congressional Budget Office, *How CBO Projects Income* (July 2013), www.cbo.gov/publication/44433.

13. For further discussion, see Congressional Budget Office, *The Distribution of Household Income and Federal Taxes, 2011* (November 2014), www.cbo.gov/publication/49440.

the distribution of income could significantly affect tax revenues and spending for some programs (such as Social Security); whether they would have a large net effect on the federal budget overall is unclear.

Interest Rates on Federal Debt

Interest rates affect the budget by changing the interest payments that the federal government makes on debt held by the public. Interest rates are currently at historic lows, but CBO projects that they will rise over the next few years and return to levels closer to their long-run averages. As a result, interest payments on federal debt held by the public, which are currently a little over 1 percent of GDP, are projected to grow to about 3 percent of GDP by 2025, even though federal debt as a percentage of GDP is projected to be only slightly larger in that year than it is currently.

However, given how much interest rates on government debt have varied in the past, projections of those rates involve a great deal of uncertainty. CBO estimates that the real interest rate on 10-year Treasury notes (that is, the rate adjusted to exclude the effects of inflation) averaged about 3 percent during the 1960s, about 1 percent during the 1970s, about 5 percent during the 1980s, about 4 percent during the 1990s, about 2 percent between 2000 and 2007, and about 1 percent during the past seven years.[14]

CBO's long-term projection of interest rates takes into account economic and financial factors such as the amount of federal debt, the rate of growth of the labor force, the rate of growth of productivity, private saving, and the amount of inflows of capital from foreign investors (see Appendix A). Different projections of those factors would imply different projections of interest rates. For example, as explained above, faster productivity growth implies higher interest rates, all else being equal. But many of the economic and financial factors that affect interest rates also affect the budget in other ways—for instance, faster productivity growth leads to faster income growth and higher revenues—and those additional effects complicate the relationship between interest rates and the budget.[15]

To isolate the budgetary effect of changes to the interest rate that the federal government pays on debt held by the public, CBO analyzed uncertainty in its projection of the difference (called the spread) between the federal government's borrowing rates and private borrowing rates. For any given level of private borrowing rates, changes to that spread affect the rate at which the federal government borrows but do not usually have significant direct effects on economic conditions or on the federal budget apart from interest payments.

The conditions that have historically determined the spread between the government's borrowing rates and private borrowing rates include portfolio preferences among U.S. and foreign investors, the perception of the underlying risk of private securities relative to federal debt, the response of financial institutions to regulations that require the holding of low-risk assets, and the liquidity of federal debt relative to that of private securities. For example, the difference between the rates of interest on 10-year Treasury notes and on highly rated corporate bonds rose from the 1990s to the 2000s as investors became more averse to risk in the wake of the sharp stock market drop of the early 2000s; even after the economy recovered, the difference remained larger than it had been before the drop.

To find a guide to the uncertainty surrounding the spread between government borrowing rates and private borrowing rates, CBO examined the average spread between the interest rate on 10-year Treasury notes and the interest rate on a large class of corporate debt (specifically, an index of corporate debt with a credit rating of Baa) during the 25-year periods beginning with the 1954–1978 period and ending with the 1990–2014 period. That spread varied over those periods by about 1 percentage point (see Figure 7-1 on page 94). However, the historical averages do not reflect certain sources of uncertainty about spreads in the future. For one thing, estimates of the risk premium—the additional return that investors require to hold assets that are riskier than Treasury securities—have been quite volatile in recent years, so more distant history may be a poor guide to the future premium. For another, although private and foreign investors alike have been eager to invest in risk-free U.S. assets in recent

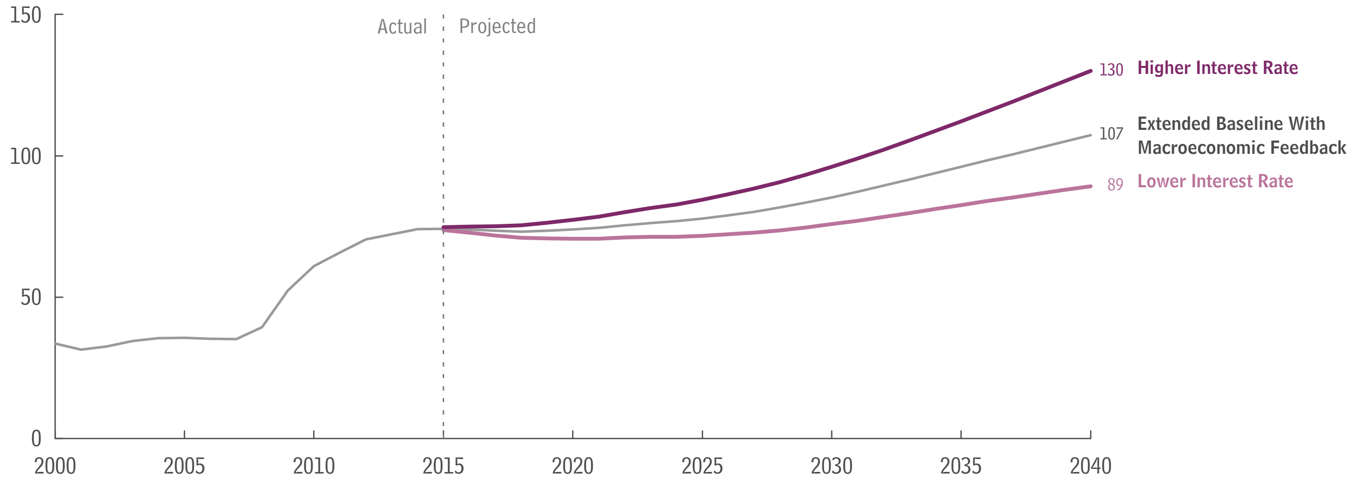
14. To calculate historical real interest rates, the actual rates were adjusted using changes in the consumer price index. Past values of the consumer price index were adjusted to account for changes over time in how that index measures inflation.

15. In addition, many economic and financial factors that affect the government's borrowing rate also affect interest rates in the private sector, which in turn affect private capital investment and thus income and output.

Figure 7-4.

Federal Debt Given Different Interest Rates

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The higher interest rate is 0.75 percentage points higher—and the lower interest rate is 0.75 percentage points lower—than the rate used for each year in the extended baseline with macroeconomic feedback.

Federal debt refers to debt held by the public. Estimates for the extended baseline with macroeconomic feedback are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

years, those investors may change their preferences as financial markets in emerging economies continue to develop and become more attractive. Furthermore, the effect that the regulatory changes that were enacted in response to the 2007–2009 financial crisis will have on investors' demand for corporate and federal debt remains very uncertain. To account for those sources of uncertainty as well as for other factors that may not be fully represented by the particular measure of the spread used and the historical period analyzed, CBO expanded the range of uncertainty used for this analysis from the 1.0 percentage point suggested by the historical data to 1.5 percentage points.[16]

16. For the extended baseline with macroeconomic feedback, CBO projects that the federal government's nominal borrowing rate wil average 3.9 percent between 2015 and 2040. If the spread between government and private borrowing rates was within the 1.5 percentage-point range of uncertainty, then after accounting for macroeconomic feedback, the government's nominal borrowing rate would be expected to be between 3.1 percent and 4.8 percent, on average, over that period.

Those alternative projections for the interest rate on federal debt held by the public would lead to the following alternative budget projections:

- If the spread between the government and private borrowing rates was 0.75 percentage points larger than the average incorporated in the baseline—resulting in a lower government borrowing rate—but the economy was otherwise the same, then net interest would equal 3.2 percent of GDP by 2040 instead of the 4.7 percent projected in the extended baseline with macroeconomic feedback.[17] Federal debt held by the public would be 89 percent of GDP in 2040 rather than the 107 percent that CBO projected in that baseline (see Figure 7-4). The 25-year fiscal gap

17. The estimated effects on budget projections of changes in the government's borrowing rates do not incorporate any changes in remittances by the Federal Reserve or in the relative amounts of different types of taxable income (for example, profits and interest income). Such changes would have additional budgetary implications.

would be 0.6 percent of GDP rather than the 1.1 percent that CBO projects under the extended baseline.[18]

- If the spread between the government and private borrowing rates was 0.75 percentage points smaller than the average incorporated in the baseline but the economy was otherwise the same, then net interest would equal 6.9 percent of GDP in 2040, and federal debt held by the public would be projected to reach 130 percent of GDP. The 25-year fiscal gap would rise to 1.6 percent of GDP.

Federal Spending on Medicare and Medicaid

The federal government pays for health care through Medicare, Medicaid, subsidies for insurance purchased through the exchanges established under the Affordable Care Act, and other programs as well as through tax preferences, especially the exclusion for employment-based health insurance.[19] In CBO's extended baseline, federal spending on health care per beneficiary increases more slowly in the future than it has, on average, in recent decades, though it still substantially outpaces the growth of potential (that is, maximum sustainable) output per capita. But the future growth of health care costs is quite uncertain, and it is consequently a significant source of budgetary uncertainty. CBO assesses the effects of uncertainty in the future growth of health care costs on the federal budget by varying the growth rate of costs in the two largest components of federal spending on health care, Medicare and Medicaid.

Many factors will affect Medicare and Medicaid spending per beneficiary in the long term (for further discussion, see Chapter 2). One of them is the extent to which advances in health care technology raise or lower costs. New medical procedures or treatments may prove more effective in helping patients, which could lower costs. However, such procedures and treatments are often very expensive; even services that are relatively inexpensive could make spending rise quickly if ever-growing numbers of patients used them.[20] Other factors that could affect health care costs are changes in the structure of payment systems and innovations in the delivery of health care.

In addition, Medicare and Medicaid spending will be affected by the health of the population. Outlays for Medicare and Medicaid depend in part on the prevalence of certain medical conditions—cardiovascular and pulmonary diseases, diabetes, arthritis, and depression, for example—among beneficiaries. The prevalence of such conditions could evolve in unexpected ways for various reasons, including changes in behavior (for example, in smoking rates, levels of physical activity, or dietary patterns), new treatments for various illnesses, new medical interventions that reduced the occurrence or severity of certain conditions or diseases, and the emergence of epidemics.

The measure that CBO examined for this analysis of uncertainty was excess cost growth—that is, the difference between the growth rate of health care spending per capita and the growth rate of potential output per capita.[21] In the 25-year periods starting with the 1966–1990 period and ending with the 1989–2013 period, excess cost growth for the health care system as a whole varied by about 1.5 percentage points (see Figure 7-1 on page 94). CBO used a 1.5 percentage-point range of variation and analyzed the effects of rates of excess cost growth for Medicare and Medicaid that were 0.75 percentage points above and below the rate of growth for each year in the extended baseline.[22] (CBO focused on Medicare and Medicaid because the projected

18. In estimating the fiscal gap under the alternative projections for interest rates, CBO altered the rate used to discount future taxes, noninterest spending, and debt by the same amount as other interest rates. For example, in calculating the fiscal gap under the projection with lower interest rates, future primary deficits (that is, deficits excluding interest payments) and the end-of-period debt are given a greater weight than they are under projections with higher interest rates.

19. Under that provision of the tax code, most payments that employers and employees make for health insurance coverage are exempt from income and payroll taxes.

20. See Congressional Budget Office, *Technological Change and the Growth of Health Care Spending* (January 2008), www.cbo.gov/publication/41665.

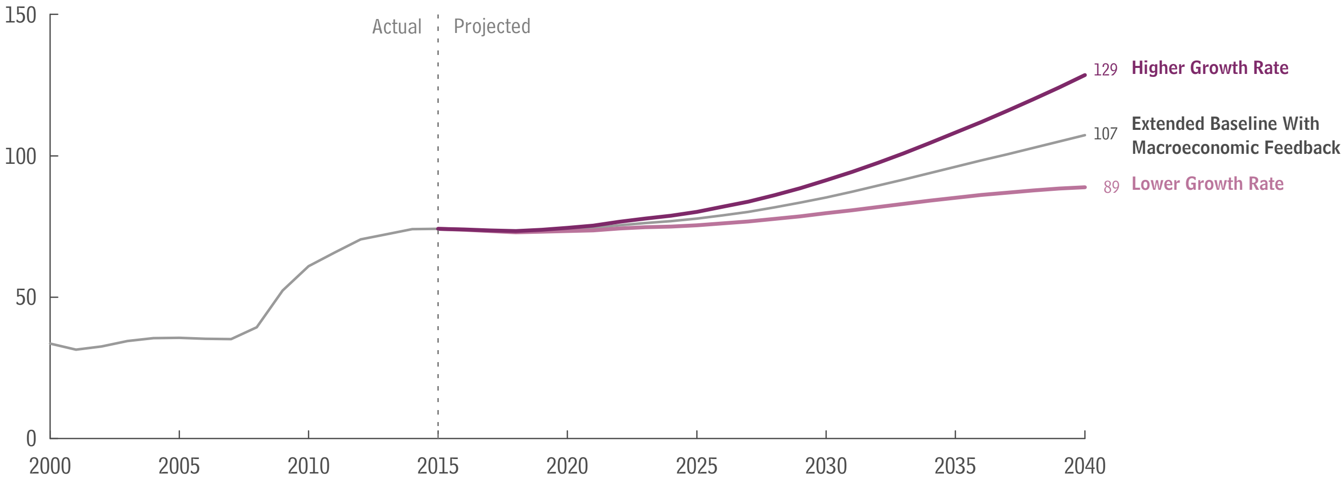
21. The definition and calculation of excess cost growth are discussed in more detail in Chapter 2.

22. In the extended baseline, CBO projects that the rate of excess cost growth in Medicare and Medicaid for each year will match the rate in the agency's baseline projections for the next 10 years and then move in the succeeding 15 years toward the projected underlying path. The estimated underlying rate starts at the rate of excess cost growth experienced in the health care system in recent decades and declines gradually as people respond to the pressures of rising costs.

Figure 7-5.

Federal Debt Given Different Rates of Growth of Federal Health Care Spending

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

The higher growth rate of per-beneficiary federal spending on Medicare and Medicaid is 0.75 percentage points higher—and the lower growth rate is 0.75 percentage points lower—than the growth rate used for each year in the extended baseline with macroeconomic feedback.

Federal debt refers to debt held by the public. Estimates for the extended baseline with macroeconomic feedback are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

size of those programs means that variations in their rates of growth would have particularly large effects on the federal budget.)

Those alternative projections for the growth of health care spending would lead to the following alternative budget projections:

- If Medicare and Medicaid spending per beneficiary rose 0.75 percentage points per year more slowly than in the extended baseline, federal debt held by the public would be 89 percent of GDP in 2040 rather than the 107 percent that CBO projects under the extended baseline with macroeconomic feedback (see Figure 7-5). The 25-year fiscal gap would be 0.5 percent of GDP rather than the 1.1 percent that CBO projects under the extended baseline.

- If Medicare and Medicaid spending per beneficiary rose 0.75 percentage points per year more quickly than in the extended baseline, federal debt held by the public would be 129 percent of GDP in 2040. The 25-year fiscal gap would rise to 1.8 percent of GDP.

Multiple Factors

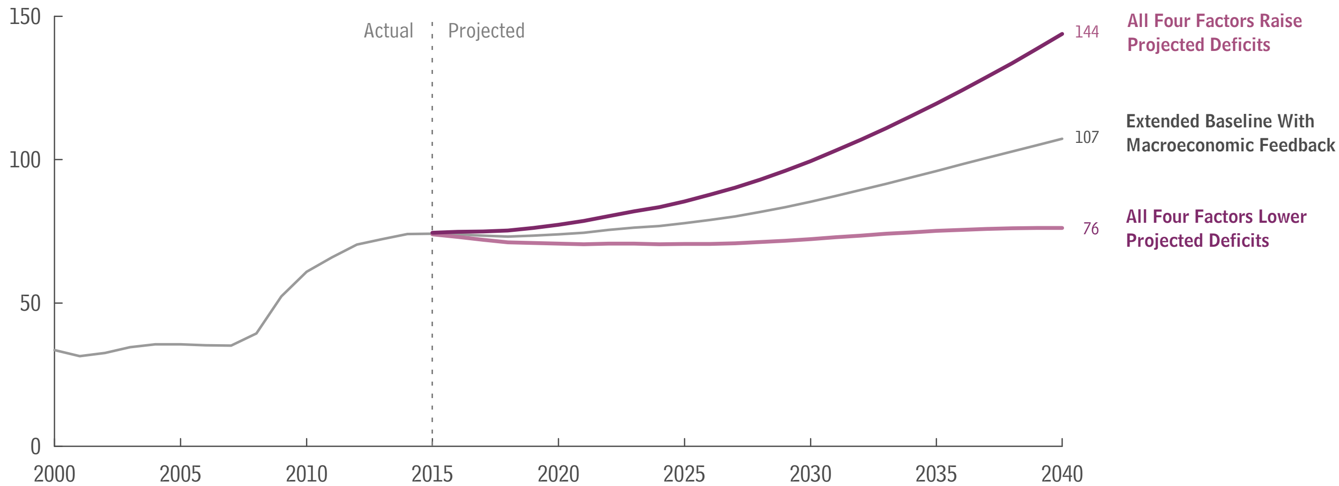
The previous cases illustrated what would happen to the federal budget if a single factor differed from the projections that CBO used in the extended baseline. Undoubtedly, however, multiple factors will differ from CBO's projections. In addition, estimating the budgetary consequences of such a circumstance is more complicated than simply adding together the outcomes of the individual cases. For example, higher-than-projected health care costs would have a larger effect on the budget if interest rates on federal debt were also higher than CBO projects—because the government would have to pay more interest on debt that resulted from the additional health care spending.

To account for the interactions among the key variables and the fact that having just one individual factor reach the end of its range is much more likely than having all

Figure 7-6.

Federal Debt Given Different Rates of Mortality Decline, Productivity Growth, Interest, and Growth of Federal Health Care Spending

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

Notes: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period.

For this figure, CBO used ranges for the four factors that are 60 percent as large as the ranges used for the individual cases (shown in Figures 7-2 to 7-5).

Federal debt refers to debt held by the public. Estimates for the extended baseline with macroeconomic feedback are CBO's central estimates from ranges determined by alternative assessments about how much deficits crowd out investment in capital goods such as factories and computers (because a larger portion of private saving is being used to purchase government securities) and about how much people respond to changes in after-tax wages by adjusting the number of hours they work.

four do so simultaneously, CBO used smaller ranges for each of the four factors when they are assumed to change together than it used for them individually. It analyzed illustrative cases in which all four factors varied from the baseline by 60 percent of their individual ranges. According to CBO's analysis of the historical data, joint variation to that extent yields outcomes for federal debt that are about as likely as the outcomes when an individual factor changes to the full extent of its range. For example, in the cases discussed above, the range for the rate of productivity growth was 1 percentage point, yielding growth rates that were 0.5 percentage points higher and lower than the values in the extended baseline; but for the combined projections, the range for the rate of productivity growth is 0.6 percentage points, yielding growth rates that span the baseline values by 0.3 percentage points.

Varying the four factors together in that way would lead to the following budget projections:

- If mortality rates declined 0.3 percentage points per year more slowly, productivity grew 0.3 percentage points per year more quickly, the difference between the average interest rate on government debt and private interest rates was about 0.45 percentage points greater, and federal costs per beneficiary for Medicare and Medicaid grew by about 0.45 percentage points per year more slowly than under the extended baseline, federal debt held by the public would be 76 percent of GDP in 2040—about what it is now—rather than the 107 percent that CBO projects under the extended baseline with macroeconomic feedback (see Figure 7-6). The 25-year fiscal gap would be 0.6 percent of GDP rather than the 1.1 percent that CBO projects under the extended baseline.

- If mortality rates declined 0.3 percentage points per year more quickly, productivity grew 0.3 percentage points per year more slowly, the difference between the average interest rate on government debt and private interest rates was about 0.45 percentage points smaller, and federal costs per beneficiary for Medicare and Medicaid grew by about 0.45 percentage points per year more quickly than under the extended baseline, federal debt held by the public would be 144 percent of GDP in 2040. The 25-year fiscal gap would be 1.7 percent of GDP.

Other Sources of Uncertainty Related to Demographic, Economic, and Other Trends

CBO's long-term budget estimates depend on projections of numerous variables in addition to those analyzed above. (Many of those variables are discussed in detail in Appendix A.) Although the factors discussed in the previous section are four of the more important ones, they are intended to provide illustrative examples, not to be exhaustive. Every variable has some uncertainty associated with it. For instance, demographics, labor force growth, and decisions by states about Medicaid are also important, but CBO has not yet quantified the potential effects on the budget of uncertainty involving those factors.

Changes in Demographics and Labor Force Growth

Demographic factors have significant effects on economic and budgetary outcomes. For instance, GDP depends to a large degree on the size of the labor force, which is related to the number of adults between the ages of 20 and 64, and federal outlays for Medicare, Medicaid, and Social Security are closely linked to the number of people who are at least 65 years old. Higher rates of fertility or greater immigration flows would generally cause federal spending to decrease relative to GDP because they would increase the ratio of adults ages 20 to 64 to elderly adults. (Mortality, another demographic factor that affects the economy and the budget, was addressed separately above.)

The growth of the labor force could also change for reasons other than demographic ones. Projections of the labor force are based on estimates of the size of the population and estimates of the rates of participation in the labor force by people in different demographic groups. Those participation rates in turn depend on a number of factors, including economic conditions, cultural shifts, and public policies (especially those that involve taxes on labor or that directly affect people's incentive to work in some other way).[23] The overall rate of participation in the labor force has varied considerably over time. For example, it averaged 59 percent in the 1950s and 1960s, increased to more than 67 percent by 2000, and has declined since then, averaging a little more than 62.8 percent in the first four months of 2015. The large increase from the 1960s to 2000 was mostly the result of an increasing number of women in the labor force. If the next 25 years saw some kind of cultural shift that had a similarly large effect on the overall rate of participation in the labor force, labor force growth could be significantly different from what CBO expects.

Faster or slower labor force growth would produce better or worse budgetary outcomes, all else being equal. If the labor force grew more quickly than projected for the extended baseline, the faster economic growth would result in higher revenues, smaller budget deficits, and a smaller ratio of federal debt to GDP. In contrast, if the labor force grew more slowly than projected in the extended baseline, the slower economic growth would result in lower revenues, larger budget deficits, and a greater ratio of debt to GDP.

Decisions by States About Medicaid

State governments have flexibility in administering their Medicaid programs, and the decisions that they make about eligibility, benefits, and payments to providers affect the federal budget because the federal government pays a large share of Medicaid's costs. One source of uncertainty is whether states will maintain or increase Medicaid spending—by obtaining program waivers to expand eligibility to new population groups, enhancing outreach efforts to increase enrollment of eligible people, or expanding covered benefits—as rising earnings reduce the number of children and nondisabled adults who are eligible for the program over time. Decisions by states could significantly decrease or increase federal expenditures for Medicaid relative to the amounts in CBO's projections.

Potential Developments in the Economy and Their Effects on the Budget

The range of outcomes presented above conveys only part of the uncertainty associated with long-term budget projections. They do not account for other plausible

23. The rate of participation in the labor force has changed over time within demographic groups; see Congressional Budget Office, *CBO's Labor Force Projections Through 2021* (March 2011), www.cbo.gov/publication/22011.

but unpredictable developments that could increase or decrease federal debt relative to CBO's projections. Such possible developments could include an economic depression like the one that occurred in the United States in the 1930s; unexpectedly large losses on federal financial obligations, such as mortgage guarantees; and unpredictable catastrophes, such as a major natural disaster or world war, the effects of changes in climate, or the discovery of valuable natural resources.

A Severe Economic Downturn

In general, when economic output rises or falls, the federal budget is automatically affected. For example, economic downturns can reduce revenues significantly and raise outlays for safety-net programs, such as unemployment insurance and nutrition assistance.[24] In addition, such downturns have historically prompted policymakers to enact legislation that further reduces revenues and increases federal spending—to help people suffering from the weak economy, to bolster the financial condition of state and local governments, and to stimulate additional economic activity and employment. The budgetary effects of the recent recession were particularly large: Federal debt increased from 35 percent of GDP at the end of 2007 to 70 percent at the end of 2012, in large part because of the recession and weak recovery and the policy responses enacted to counter those developments.

The long-term projections of output and unemployment in this report reflect economic trends from the end of World War II to the present, a period that included several economic downturns that were not fully offset by upturns of similar magnitude.[25] But the projections do not account for the possibility of a severe economic downturn like the Great Depression of the 1930s. Such events are rare; for that reason and others, their magnitude and timing cannot readily be predicted. If such an event occurred in the next 25 years, federal debt would probably be substantially greater than projected in CBO's extended baseline.

Changes in Losses on Federal Insurance or Credit Programs

The federal government supports a variety of private activities through federal insurance and credit programs that provide loans and loan guarantees.[26] CBO includes the expected losses from those credit and insurance programs in its baseline projections. Significantly greater losses could result from certain unexpected events, such as a major disruption in the financial system or a deep slump in the economy. Alternatively, long periods of financial and economic stability could lead to smaller losses.

Federal insurance and credit programs generate losses when the support provided by the federal government exceeds the money taken in by the programs through fees, loan repayments, interest payments, asset sales, wage garnishment, and other means. For example, in the wake of the recent housing crisis, widespread defaults on guaranteed mortgages led to substantial outlays by the federal government. Widespread defaults on student loans or the bankruptcy of numerous companies with underfunded pension plans could lead to analogous costs for the federal government in the future.[27] Conversely, long periods of particularly strong economic growth could allow federal insurance and credit programs to collect higher-than-projected repayments and cover lower-than-projected expenses.

24. See Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), Appendix D, www.cbo.gov/publication/49892.

25. Since the end of World War II, the unemployment rate has been about one-quarter of one percentage point higher, on average, than CBO's estimate of the natural rate of unemployment (the rate arising from all sources except fluctuations in aggregate demand). That difference implies that periods of significant economic weakness (such as the 2007–2009 recession and its aftermath) have pushed the unemployment rate above CBO's estimate of the natural rate more than periods of significant economic strength have pushed it below that estimate. Consistent with that finding is CBO's projection that the unemployment rate in the long term will be 5.3 percent, which is about one-quarter of one percentage point higher than CBO's estimate of the natural rate of unemployment in the long term. For further discussion, see Appendix A.

26. Federal insurance programs provide coverage for deposits at financial institutions (through the Federal Deposit Insurance Corporation), for workers' pensions (through the Pension Benefit Guaranty Corporation), and for property against damage by floods (through the National Flood Insurance Program), among other things. The largest federal credit programs provide mortgage loan guarantees (through the Federal Housing Administration, Fannie Mae, and Freddie Mac); student loans; and federally backed loans to businesses (through the Small Business Administration, for example). There are a number of smaller programs, including the loan guarantees provided by the Department of Energy and the terrorism risk insurance program administered by the Treasury Department.

27. For more discussion, see James D. Hamilton, *Off-Balance-Sheet Federal Liabilities*, Working Paper 19253 (National Bureau of Economic Research, July 2013), www.nber.org/papers/w19253.

Moreover, the federal government may have significant implicit liabilities apart from the liabilities created by formal government programs. In the event of a financial crisis, for example, federal policymakers might decide to provide monetary support to the financial system, as they did during the recent financial crisis. Such support could increase federal outlays above the amounts in the extended baseline.

Catastrophes

The federal government also faces implicit obligations in the case of catastrophes. Small-scale natural and man-made disasters occur fairly often in the United States; they may seriously damage local communities and economies, but they have rarely had significant, lasting impacts on the national economy. By contrast, a catastrophe could affect budgetary outcomes by reducing economic growth over a number of years, leading to substantial increases in federal spending. For example, the nation could experience a massive earthquake, a pandemic, an asteroid strike, a geomagnetic storm from a large solar flare, or a nuclear meltdown or attack that rendered a significant part of the country uninhabitable. Participation in a major war could also have significant economic and budgetary impacts: The ratio of federal debt held by the public to GDP rose by 60 percentage points during World War II, for instance. Because catastrophic events are extremely rare, it is very difficult to estimate the probability of their future occurrence and their possible effects on the budget.

Climate Change

CBO's extended baseline does not explicitly incorporate the effects of climate change. It implicitly includes some small effects by reflecting historical spending on such programs as federal crop insurance, federal flood insurance, and the Federal Emergency Management Agency's disaster relief program.[28] Aside from those implicit changes in federal outlays, the extended baseline does not incorporate any budgetary effect that climate change might have; it does not, for example, account for the effect on federal tax revenues that climate change could have if it affected the nation's economic output.

Substantial uncertainty surrounds any projection that attempts to account for the impact that climate change might have on the economy or on the budget. That uncertainty arises from several sources, including the unpredictability of global economic activity and technology development—both of which affect the amount of emissions in the future—as well as limitations in current data and the imperfect understanding of physical processes and of many aspects of the interacting components (land, air, water and ice, and life) that make up the Earth's climate system. In addition to the unpredictability of climate change itself, the impact that any such change would have on the economy and the budget is also quite uncertain.

CBO has not undertaken a full analysis of the budgetary costs stemming from climate change, but it is currently analyzing the potential costs of future hurricanes.[29] That analysis suggests that the costs of future hurricane damage will rise at a faster rate than GDP; however, the amount of additional hurricane damage is likely to remain small enough, on average, that the resulting federal expenditures would not significantly affect the general budget categories in which hurricane-related spending falls.

Three factors that influence the rate of growth of future hurricane damage are sea levels, the frequency of severe hurricanes, and the amount of development in coastal areas (because the damage caused by hurricanes will depend, in part, on the amount of people and property in harm's way):

- Hurricane damage is expected to increase over time because climate change is projected to lead to rising sea levels, which will tend to increase damage from storm surges when hurricanes occur.

28. Some of the programs most affected by weather-related disasters—such as federal crop insurance and flood insurance—fall into the "other mandatory spending" category in CBO's long-term projections; in CBO's extended baseline, other mandatory spending (apart from outlays for refundable tax credits) is projected to continue to decline as a share of GDP after the 10-year period that CBO's baseline projections span at the same rate as it is projected to decline during the last five years of that initial period. Other programs affected by weather-related disasters—such as the Federal Emergency Management Agency's disaster relief program—are discretionary; spending for those programs is projected to remain constant as a share of GDP after the 10-year baseline projection period.

29. Terry Dinan, Senior Adviser, Congressional Budget Office, "Hurricane Damage: Effects of Climate Change and Coastal Development" (presentation to the Summer Conference of the Association of Environmental and Resource Economists, San Diego, Calif., June 5, 2015), www.cbo.gov/publication/50230.

- Climate change may increase the occurrence of the most intense (Category 4 and 5) storms in the North Atlantic Basin, leading to more damage in the United States.

- The growth in hurricane damage attributable solely to increases in coastal development is projected to be slower than the growth of the economy overall. That slower rate stems from the expectation that new development will tend to be denser (reducing wind damage per structure if buildings are closer together and storm surge damage per structure if buildings are taller), more expensive construction and therefore less vulnerable to storm damage.

All told, CBO projects that the amount of damage attributable to climate change and coastal development will probably be around 0.05 percent of GDP in the 2030s and less than 0.1 percent of GDP in the 2070s.

Many estimates suggest that the effect of climate change on the nation's economic output, and hence federal tax revenues, will probably be small over the period that is covered by CBO's long-term projections and larger, but still modest, in later years.[30] Even under scenarios in which significant warming is assumed, the projected long-term effects of climate change on GDP in the United States tend to be modest relative to underlying economic growth for two primary reasons. First, only a small share of the U.S. economy is directly affected by changes in climate; the largest effects will probably occur in the agricultural sector, which currently represents about 1 percent of total U.S. output. (The direct economic effects of climate change may be larger in other countries, particularly those for which agricultural output is a larger share of the total.) Second, some activities within the agricultural sector—crop production in the north, for example—could experience gains because of climate change. In any event, some of the effects of climate change (such as the loss of biodiversity), neither directly relate to measured economic output nor affect tax revenues. CBO continues to monitor research on the effects of climate change on the U.S economy, to consider how those effects might alter the federal budget outlook, and to evaluate federal policies that may lead to lower emissions or mitigate damage from changes in the climate.

In addition to uncertainty about the magnitude of disasters caused by climate change, there is uncertainty about how lawmakers would respond to them. In the future, lawmakers could increase funding above the amounts in CBO's projections if the effect of climate change on the frequency and magnitude of weather-related disasters became significantly larger. For example, increased damage from storm surges might lead the Congress to pass additional emergency supplemental appropriations for disaster relief or to approve legislation providing funding to protect infrastructure that is vulnerable to rising sea levels. Or lawmakers could amend existing laws to reduce federal spending on weather-related disasters. For instance, the Congress might decide to alter flood insurance or crop insurance programs in a way that provides insured parties with greater incentive to avoid potential damage. But CBO's baseline projections, which are built on current law, cannot capture such possible changes.

Natural Resources

The future discovery and development of productive natural resources may cause federal receipts to increase. For example, recent advances in combining two drilling techniques, hydraulic fracturing and horizontal drilling, have allowed access to large deposits of shale resources—that is, crude oil and natural gas trapped in shale and certain other dense rock formations. Virtually nonexistent a decade ago, the development of shale resources has boomed in the United States in recent years, affecting two kinds of federal receipts—federal tax revenues and payments to the government by private developers of federally owned resources. By boosting GDP, shale development increases tax receipts. Because some of the shale resources being developed are federally owned, developers must make payments to the federal government; however, most of the nation's shale resources are not federally owned, so those payments do not increase federal receipts by a significant amount.[31] Advances in the development of other resources may also contribute to federal receipts and make federally owned resources more valuable.

30. Congressional Budget Office, *Potential Impacts of Climate Change in the United States* (May 2009), www.cbo.gov/publication/41180.

31. Congressional Budget Office, *The Economic and Budgetary Effects of Producing Oil and Natural Gas From Shale* (December 2014), www.cbo.gov/publication/49815.

Implications of Uncertainty for the Design of Fiscal Policy

Policymakers could take uncertainty into account in various ways when making fiscal policy choices.[32] For example, they might decide to design policies that reduced the budgetary implications of certain unexpected events. Policymakers might also decide to provide a buffer against events with negative budgetary implications by aiming for lower debt than they would otherwise.

Reducing the Budgetary Implications of Unexpected Events

Fiscal policy cannot eliminate the risk factors that create uncertainty about budgetary outcomes, but it can reduce the budgetary implications of those factors. However, reducing budgetary uncertainty for the federal government could have unwanted consequences, such as shifting risk to individuals. Under current law, for example, growth in Medicare and Medicaid outlays per beneficiary depends on the growth of per capita health care costs. Some policymakers have proposed that growth in federal outlays per beneficiary of those programs be linked instead to measures of overall economic growth.[33] Such a change could affect national spending for health care, the federal budget, individuals' costs, and the budgets of state and local governments. It might greatly reduce uncertainty about future federal outlays for Medicare and Medicaid, but it might also greatly increase uncertainty about the future costs borne by the programs' beneficiaries and by state and local governments.[34]

Similarly, policymakers could reduce the budgetary implications of uncertainty about future life expectancy by indexing the eligibility age for programs such as Social Security or Medicare to average life spans. Under current law, if longevity increased more than expected, outlays for federal health care and retirement programs would exceed projections. If policies were changed so that the age of eligibility for those programs rose automatically with increases in longevity, the budgetary effects of such increases would be dampened. However, people would face greater uncertainty about the timing and size of the benefits that they would receive, and the effects would vary among subgroups of the population.

In addition, policymakers could reduce the budgetary implications of unexpected rises in interest rates by increasing the share of government borrowing that is done through longer-term securities. Using that approach, the Treasury could lock in interest rates for a considerable period. However, interest rates on longer-term debt are typically higher than rates on shorter-term debt, so that approach would probably raise the interest that the federal government paid. Moreover, if interest rates were locked in for a long period, the federal government would benefit less from unexpected *declines* in interest rates.

Whether or not the federal budget directly bears the risk of uncertain outcomes, all risk is ultimately distributed among individuals—as taxpayers, as beneficiaries of federal programs, or as both. If federal spending for certain programs turned out to be higher than projected, the additional imbalance could be offset only through higher revenues or lower outlays for other programs or activities at some point in the future. If the additional imbalance was not offset, then deficits would be larger, resulting in lower future income. Conversely, if budgetary imbalances were smaller than expected, then an opportunity would exist to lower taxes or boost spending; it would also be possible to reduce future deficits, resulting in higher income. Which income groups or generations benefited the most—or bore the largest burden—from unexpected budgetary imbalances would depend on the policies that lawmakers enacted to deal with such imbalances.

Reducing Federal Debt

As an alternative or complementary approach, policymakers could improve the federal government's ability to withstand the effects of events that would significantly worsen the budgetary outlook. In particular, reducing the amount of federal debt held by the public would give future policymakers more flexibility in responding to extraordinary events. For example, a financial crisis in the future might have significant negative economic and budgetary implications—just as the 2007–2009 financial

32. See Alan J. Auerbach and Kevin Hassett, "Uncertainty and the Design of Long-Run Fiscal Policy," in Auerbach and Ronald D. Lee, eds., *Demographic Change and Fiscal Policy* (Cambridge University Press, 2001), pp. 73–92, http://tinyurl.com/p93enfp.

33. For examples of these proposals, see Congressional Budget Office, *Preliminary Analysis of the Rivlin-Ryan Health Care Proposal* (attachment to a letter to the Honorable Paul D. Ryan, November 17, 2010), www.cbo.gov/publication/21928.

34. Most proposed policy changes of that sort would affect both the expected amounts of federal outlays and the uncertainty about those outlays, but those two effects are conceptually distinct.

crisis did: The ratio of federal debt held by the public to GDP increased by 35 percentage points between 2007 and 2012. If another financial crisis prompted a similar increase when the ratio of federal debt to GDP was already at a high level (such as its current level of 74 percent), policymakers might be reluctant to accept the initial cost of a desired intervention in the financial system or the economy, even if they expected to recoup at least part of that cost over time.

In addition, a high ratio of debt to GDP increases the risk of a fiscal crisis in which investors lose confidence in the government's ability to manage its budget and the government in turn loses its ability to borrow at affordable rates.[35] There is no way to predict the amount of debt that might precipitate such a crisis, but starting from a position of relatively low debt would reduce the risk.

35. That sort of crisis might be triggered by an adverse event that quickly drove up the ratio of debt to GDP, such as a depression or a war. For further discussion, see Congressional Budget Office, *Federal Debt and the Risk of a Fiscal Crisis* (July 2010), www.cbo.gov/publication/21625.

APPENDIX

A

CBO's Projections of Demographic, Economic, and Other Trends

The long-term budget estimates in this report depend on projections by the Congressional Budget Office for a host of demographic, economic, and other variables. CBO refers to that collection of projections as its economic benchmark, a measure that is consistent with the agency's baseline economic and budgetary projections for the ensuing 10 years. Beyond 2025, the economic benchmark generally reflects historical trends; it does not incorporate the extent to which economic output and interest rates would change if federal debt as a percentage of gross domestic product (GDP) or marginal tax rates changed after 2025, as is projected to occur under current law. (For average values from 2015 through 2040, see Table A-1. Projected annual values for the major demographic and economic variables for the next 75 years are included in the supplemental data for this report, available online at www.cbo.gov/publication/50250.)

Demographic Variables

The size and composition of the U.S. population in coming decades will affect federal tax revenues and spending as well as the overall performance of the economy. Among other effects, demographic changes will influence the size of the labor force and the number of beneficiaries of such federal programs as Medicare and Social Security. Population projections include estimates of rates of fertility, immigration, and mortality. (CBO uses projections published by the Social Security trustees for fertility rates but makes its own projections of immigration and mortality rates.) CBO anticipates that the total U.S. population will increase from 325 million at the beginning of 2015 to 394 million in 2040.

Fertility

CBO has adopted the intermediate (midrange) estimates of fertility rates published by the Social Security Administration in 2014.[1] Those values imply an average fertility rate of 2.0 children per woman between 2015 and 2040. (The Social Security trustees' report defines the fertility rate as the average number of children that a woman would have in her lifetime if, at each age of her life, she experienced the birth rate observed or assumed for that year and if she survived her entire childbearing period.)

Immigration

For its economic benchmark, CBO projects that after 2025, net annual immigration (the net result of people leaving and entering the United States) will equal 3.2 immigrants for every 1,000 members of the U.S. population, a ratio that is consistent with the data for most of the past two centuries.[2] On that basis, CBO projects, net annual immigration to the United States will amount to 1.2 million people in 2026 and 1.3 million in

1. See Social Security Administration, *The 2014 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* (July 2014), Table V.A1, www.ssa.gov/oact/tr/2014.

2. The ratio equals the estimated average net flow of immigrants between 1821 and 2002; see 2003 Technical Panel on Assumptions and Methods, *Report to the Social Security Advisory Board* (October 2003), p. 28, http://go.usa.gov/38pbH (PDF, 450 KB). That ratio also was published in 2011 Technical Panel on Assumptions and Methods, *Report to the Social Security Advisory Board* (September 2011), p. 64, http://go.usa.gov/38pE3 (PDF, 6.3 MB). For more details about U.S. immigration, see Congressional Budget Office, *A Description of the Immigrant Population—2013 Update* (May 2013), www.cbo.gov/publication/44134.

Table A-1.

Values for Demographic and Economic Variables Underlying CBO's Long-Term Budget Projections

	Average Annual Values		
	2015–2025	2015–2040	2031–2040
Demographic Variables			
Fertility rate (Children per woman)	2.0	2.0	2.0
Immigration rate (Per 1,000 people in the U.S. population)	4.0	3.6	3.2
Rate of mortality decline (Percent, adjusted for age and sex)	1.2	1.2	1.2
Economic Variables (Percent)			
Growth of the labor force	0.6	0.5	0.4
Growth of average hours worked	-0.1	-0.1	*
Unemployment			
Unemployment rate	5.4	5.4	5.3
Natural rate of unemployment	5.3	5.1	5.0
Earnings as a share of compensation	81	81	80
Inflation			
Growth of the CPI-U	2.3	2.3	2.4
Growth of the GDP deflator	1.9	2.0	2.0
Interest rates			
Real rates			
On 10-year Treasury notes and the OASDI trust funds	2.0	2.2	2.3
On all federal debt held by the public	0.9	1.5	2.0
Nominal rates			
On 10-year Treasury notes and the OASDI trust funds	4.2	4.5	4.7
On all federal debt held by the public	3.2	3.9	4.4
Growth of productivity			
Total factor productivity	1.4	1.3	1.3
Labor productivity	1.8	1.8	1.8
Growth of real earnings per worker	1.6	1.4	1.4
Growth of GDP			
Real GDP	2.3	2.2	2.2
Nominal GDP	4.3	4.3	4.2

Source: Congressional Budget Office.

Note: CPI-U = consumer price index for all urban consumers; GDP = gross domestic product; OASDI = Old-Age, Survivors, and Disability Insurance (Social Security); * = between -0.05 percent and zero.

2040. Estimates of authorized and unauthorized immigration over the long term are subject to a great deal of uncertainty, however, and the number of immigrants could be higher or lower than CBO projects. Over the past 50 years, net annual immigration (averaged over five-year periods) has varied from almost 7 to fewer than 2 immigrants per 1,000 members of the U.S. population.[3]

3. 2011 Technical Panel on Assumptions and Methods, *Report to the Social Security Advisory Board* (September 2011), p. 70, http://go.usa.gov/38pE3 (PDF, 6.3 MB).

Mortality

Demographers have concluded that mortality rates have declined steadily in the United States for at least the past half century. (Mortality rates measure the number of deaths per thousand people in a population. Historically, declines in mortality rates have varied among age groups, but for simplicity, CBO projects the same rate of decline for all ages.) In the absence of compelling reasons to expect that trends will differ in the future, CBO projects that mortality rates will continue to fall at the same pace exhibited over the 60 years from 1950 to 2010; that is, at an average rate of 1.2 percent per year.[4] That extrapolation of past trends suggests that the average life expectancy for someone born in 2040 will be 82.6 years*; in contrast, CBO estimates an average life expectancy of 79.2 years for someone born in 2015. Similarly, CBO projects that someone who turns 65 in 2040 can be expected to live another 21.8 years, on average, or 2.4 years longer than someone turning 65 in 2015 is expected to live. Those figures represent averages for all people of a given age and sex in those years.

CBO's projections also incorporate differences in mortality on the basis of age, sex, marital status, education, and lifetime household earnings. (For people under 30, the mortality projections reflect only age and sex.) CBO expects that future increases in life expectancy will be larger for people with higher lifetime earnings than for those with lower earnings—an assessment that is consistent with patterns of past increases.[5] Today, on average, a 65-year-old man whose household is in the highest one-fifth (quintile) of the distribution of lifetime earnings will live more than three years longer, CBO projects, than a man of the same age whose household is in the lowest quintile of lifetime earnings; for women, that difference in life span is more than a year. CBO projects that by 2040, men in households with high lifetime earnings will live more than five years longer than men in households with low lifetime earnings; the corresponding difference for women will be almost three years.

Economic Variables

For the 2015–2025 period, CBO's benchmark projections of economic variables—such as the size of the labor force, inflation, interest rates, and earnings per worker—match the values in the agency's January 2015 economic forecast (which underlies the agency's most recent 10-year budget projections).[6] Beyond 2025, the economic benchmark generally reflects the experience of the past few decades, adjusted to account for projected demographic developments and an assumption that the ratio of debt to GDP and effective marginal tax rates will remain stable.[7] Thus, it does not incorporate the extent to which economic output and interest rates would change if federal debt as a percentage of GDP or if marginal tax rates changed after 2025, as is projected to occur under current law. Rather, the benchmark is governed by the assumption that federal debt held by the public will be kept at 78 percent of GDP (the percentage at the end of 2025, according to CBO's baseline budget projections) and that effective marginal tax rates on income from labor and capital will remain constant at their 2025 levels. (Chapter 6 presents some estimates of the economic effects of projected deficits and marginal tax rates under CBO's extended baseline and some alternative policies.)

The Labor Market

Benchmark projections for the labor market include estimates of the growth of the labor force, the average number of hours that people work, the rate of unemployment, the share of total compensation that people receive in the form of earnings, and the share of those earnings that is subject to Social Security payroll taxes. Those factors affect the amount of tax revenues that the government

4. That projection is greater than the 0.8 percent average annual decline projected in the Social Security trustees' 2014 report but less than the 1.3 percent average annual decline that is consistent with methods recommended by the Social Security Advisory Board's 2011 Technical Panel on Assumptions and Methods. The panel's recommendation reflects a belief that the decrease in mortality rates will be larger in the future than in the past because of a decline in tobacco use. However, because of uncertainty about the possible effects of many other factors in the future, such as obesity rates and advancements in medical technology, CBO has based its mortality projections on a simple extrapolation of past trends. For additional discussion, see Joyce Manchester, "Why CBO Changed Its Approach to Projecting Mortality," *CBO Blog* (September 24, 2013), www.cbo.gov/publication/44598. For further discussion of mortality patterns in the past and methods for projecting mortality, see 2011 Technical Panel on Assumptions and Methods, *Report to the Social Security Advisory Board* (September 2011), pp. 55–64, http://go.usa.gov/38pE3 (PDF, 6.3 MB). For additional background, see Hilary Waldron, "Literature Review of Long-Term Mortality Projections," *Social Security Bulletin*, vol. 66, no. 1 (September 2005), pp. 16–30, http://go.usa.gov/XKGk; and John R. Wilmoth, *Overview and Discussion of the Social Security Mortality Projections*, Working Paper (Social Security Advisory Board, 2003 Technical Panel on Assumptions and Methods, May 2005), http://go.usa.gov/38dce (PDF, 480 KB).

5. For more information about mortality differences among groups with different earnings, see Congressional Budget Office, *Growing Disparities in Life Expectancy* (April 2008), www.cbo.gov/publication/41681; and Julian P. Cristia, *The Empirical Relationship Between Lifetime Earnings and Mortality*, Working Paper 2007-11 (Congressional Budget Office, August 2007), www.cbo.gov/publication/19096.

6. See Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), Chapter 2, www.cbo.gov/publication/49892.

7. Those budgetary assumptions allow for relatively stable long-term economic projections.

[*Value corrected on June 23, 2015]

collects and the amount of federal spending on Social Security and certain other federal programs.

Growth of the Labor Force. The number of workers is expected to increase more slowly in coming decades than in past years. Although the labor force expanded at an average rate of 1.7 percent annually between 1970 and 2007 (the most recent peak in the business cycle), CBO projects slower average growth—about 0.5 percent a year—for the 2015–2040 period.

That slowdown is expected to result both from more workers' exiting the labor force and from fewer workers' entering it. The number projected to leave the labor force is anticipated to increase compared with past decades as the older members of the baby-boom generation have begun reaching retirement age (although the average age at which people leave the labor force to retire has increased slightly in recent decades). At the same time, fewer workers are projected to enter the labor force than in past decades for two main reasons: First, birth rates have declined (the average fertility rate was more than three children per woman in the 1950s and 1960s, compared with fewer than two children today), and second, the increased participation of women in the labor force has leveled off over the past several years.

Despite those trends, however, increases in longevity will cause participation in the labor force to be slightly greater than it would be otherwise, CBO anticipates. CBO expects that the average person will work three months longer for each additional year of life expectancy in the coming decades. Thus, if life expectancy is four years longer for one cohort of workers than for an earlier group, the longer-lived cohort would work an average of one extra year (everything else being equal). CBO's projections also reflect the view that older people with more education will stay in the labor force longer than those with less education because people with more education are both more likely to be in the labor force when they enter their 60s and less likely to claim Social Security benefits at an early age.

Over the 1970–2007 period, the population of people ages 20 to 64 grew by an average of 1.3 percent per year, but the labor force grew by 1.7 percent per year, mainly because of large increases in the participation rate of women (a factor that was only partly offset by a decline in the participation rate of men). Over the next decade, the gap between those growth rates will narrow, CBO projects, with the population between the ages of 20 and 64 increasing by about 0.4 percent a year and the labor force growing by about 0.6 percent a year, on average. That narrowing reflects partially offsetting effects: The increased propensity of people who are age 65 or older to continue to work and the positive effects of the strengthening labor market on participation more than offset the negative effects on participation from the reduction in people's incentive to work that results from the Affordable Care Act and the structure of the tax code. From 2015 to 2040, the labor force is projected to increase at a rate of about 0.5 percent a year, on average, which is slightly faster than the average annual growth of about 0.4 percent that is projected for the population between the ages of 20 and 64 because of increased labor force participation at older ages.

Average Hours Worked. Different subgroups of the labor force work different numbers of hours, on average. For instance, men tend to work more hours than women do, and people between the ages of 30 and 40 tend to work more hours than do people between the ages of 50 and 60. CBO's projections are based on the assumption that those differences among groups will remain stable. However, CBO also expects that over the long term, the composition of the labor force will shift toward certain groups (such as older workers) that tend to work less, slightly reducing the average number of hours worked by the labor force as a whole. CBO estimates that by 2040, the average number of hours per worker will be about 2 percent less than it is today.

The Unemployment Rate. In January 2015, CBO projected that the unemployment rate would decline from 5.7 percent at the end of 2014 to 5.3 percent at the end of 2017. That projected improvement through 2017 reflects CBO's expectation that the economic expansion will strengthen in the next few years and that the effects of certain structural factors that have contributed to higher unemployment—such as the stigma attached to long-term unemployment and the possible erosion of unemployed workers' job skills—will diminish.[8] The projections for 2018 and 2019 are largely based on the transition to a period when the relationship between the unemployment rate and the natural rate of unemployment is expected to match its historical average. (The natural rate of

8. See Congressional Budget Office, *The Slow Recovery of the Labor Market* (February 2014), www.cbo.gov/publication/45011.

unemployment is the rate that results from all sources other than fluctuations in overall demand related to the business cycle.) As a result, the unemployment rate is projected to increase to 5.5 percent by 2020, when the natural rate of unemployment is expected to be 5.3 percent.[9]

CBO projects that in 2020 and later, the average unemployment rate will be about one-quarter of a percentage point higher than the natural rate of unemployment. That projection is based not on a forecast of specific cyclical movements in the economy but rather on CBO's estimate that the unemployment rate has been roughly that much higher than the natural rate since the end of World War II, on average, and has been higher than the natural rate in each of the past five business cycles.

After 2025, the average unemployment rate is projected to decline as the natural rate of unemployment slowly moves downward, continuing its previous trend as structural factors continue to fade. The natural and actual rates of unemployment are projected to decrease to 5.0 percent and 5.3 percent, respectively, by 2028 and then to remain at those levels.

Earnings as a Share of Compensation. Workers' total compensation consists of taxable earnings and nontaxable benefits, such as paid leave and employers' contributions to health insurance and pensions. Over the years, the share of total compensation paid in the form of earnings has slipped—from about 90 percent in 1960 to about 80 percent in 2014—mainly because the cost of health insurance has grown more quickly than has total compensation.[10]

Looking ahead, CBO expects that health care costs will continue to rise more rapidly than earnings, a trend that by itself would further decrease the proportion of compensation that workers receive as earnings. However, the Affordable Care Act imposed an excise tax on some employment-based health insurance plans that have premiums above a specific threshold. Some employers and workers will respond to that tax—which is scheduled to take effect in 2018—by shifting to less expensive plans, thereby reducing the share of compensation composed of health insurance premiums and increasing the share composed of earnings. CBO projects that the effects of the excise tax on the mix of compensation will roughly offset the effects of rising costs for health care for a few decades; after that, the effects of rising health care costs will outweigh the effects of the excise tax.[11] As a result, in CBO's benchmark, the share of compensation that workers receive as earnings is projected to remain near 80 percent through 2040. (For more about the projected effects of the excise tax, see Chapter 5; for a discussion of projected changes in the costs of health care, see Chapter 2.)

Share of Earnings Below the Taxable Maximum. Most workers are in jobs that are covered by Social Security—their earnings are subject to Social Security payroll taxes. (A small segment of the workforce, mostly people who work for some state and local governments and members of the clergy, have jobs that are excluded from such coverage.) Covered earnings are expected to be about 85 percent of all earnings in 2015. Social Security payroll taxes are levied only on covered earnings up to a maximum annual amount ($118,500 in 2015). Earnings below that amount are taxed at a combined rate of 12.4 percent, split between the employer and employee (self-employed workers pay the full amount), and no tax is paid on earnings above the cap. The taxable maximum has remained a nearly constant proportion of the average wage since the mid-1980s, but because earnings have grown more for higher earners than for others, the portion of covered earnings on which Social Security taxes are paid has fallen from 90 percent in 1983 to 81 percent now. CBO expects that unequal growth in earnings to continue at least for the next decade, and therefore the portion of earnings subject to Social Security tax is projected to fall to about 79 percent by 2025 and to decline slightly thereafter.

Inflation

CBO's economic benchmark includes projections of the rate of inflation in the prices of various categories of goods and services, as measured by the annual rate of

9. See Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), pp. 30 and 50, www.cbo.gov/publication/49892.

10. For more details, see Congressional Budget Office, *How CBO Projects Income* (July 2013), www.cbo.gov/publication/44433.

11. CBO anticipates that the effects of the excise tax on the taxable share of compensation will diminish over time, both because it expects that most people will continue to want a significant amount of health insurance and because the Affordable Care Act set minimum amounts of coverage for health insurance plans. Therefore, the number of additional people moving to less expensive insurance plans will eventually dwindle.

change in the consumer price index for urban wage earners and clerical workers (CPI-W) and in the consumer price index for all urban consumers (CPI-U). CBO projects that inflation will average 2.3 percent over the 2015–2040 period. The projected long-term rate is similar to the average rate of inflation since 1990, a period in which growth in the CPI-U averaged 2.6 percent a year.

The annual inflation rate for all final goods and services produced in the economy, as measured by the rate of increase in the GDP deflator, is projected to average 0.4 percentage points less than the annual increase in the consumer price indexes over the long term.[12] The GDP deflator grows more slowly than the consumer price indexes because of the different methods used to calculate them and also because it is based on the prices of a different set of goods and services.

Interest Rates

CBO's economic benchmark includes projections of various interest rates that the federal government pays to borrow money, such as the rate on 10-year Treasury notes, the average rate on federal debt held by the public, and the average rate on holdings of the Social Security trust funds.

After considering several factors, including slower growth of the labor force, CBO expects real (inflation-adjusted) interest rates on federal borrowing to be lower in the future than they have been, on average, in the past few decades. For example, the real interest rate on 10-year Treasury notes (calculated by subtracting the rate of increase in the CPI-U from the nominal yield on those notes) averaged roughly 3.1 percent between 1990 and 2007.[13] From 2015 to 2040, that rate is projected to average 2.2 percent. But in the later years of the projection period, it is projected to be 2.3 percent.

Factors Affecting Interest Rates. Using past trends as a starting point for projecting interest rates over the long term requires analysts to make judgments about which periods to consider. Real interest rates were very low in the 1970s because of an unexpected surge in inflation, and those rates were quite high in the 1980s as inflation declined unexpectedly rapidly.[14] Interest rates also fell sharply during the financial crisis and recession that began in 2007. To avoid using those possibly less representative periods, CBO examined average interest rates and their determinants between 1990 and 2007 and then considered how different those determinants might be over the long term.

In CBO's assessment, the following factors will probably reduce interest rates on government securities relative to their 1990–2007 average:

- The labor force is projected to grow much more slowly in the future than it has for the past few decades. If everything else remains equal, slower growth in the labor force will raise the amount of capital per worker in the long term, reducing the return on capital and therefore also reducing the return on alternative investments, such as government bonds.[15]
- The share of total income received by high-income households is expected to remain larger in the future than it has been during the past few decades. Higher-income households tend to save a greater proportion of income, so that the difference in the distribution of income will increase the total amount of savings available for investment (other things being equal), also increasing the amount of capital per worker.
- Total factor productivity—real output per unit of combined labor and capital services—will grow slightly more slowly in the future than it has in recent decades, CBO projects. For a given rate of investment, lower productivity growth reduces both the return on capital and interest rates (all else being equal).

12. Final goods and services include goods and services bought by consumers, those purchased for investment, and those purchased by governments, as well as net exports.

13. Farther back, the real interest rate on 10-year Treasury notes averaged 3.2 percent between 1970 and 2007 and 2.9 percent between 1953 and 2007. For comparisons of historical real rates, past rates are calculated using the CPI Research Series Using Current Methods.

14. Although real interest rates are calculated by subtracting inflation rates from nominal interest rates, inflation can still affect them. If lenders set nominal interest rates assuming that inflation will be a certain percentage and it ends up being much higher, real interest rates will be lower than lenders intended. If inflation ends up being lower than expected, the opposite will occur.

15. For more information about the relationship between the growth of the labor force and interest rates, see Congressional Budget Office, *How Slower Growth in the Labor Force Could Affect the Return on Capital* (October 2009), www.cbo.gov/publication/41325.

- The risk premium—the additional return that investors require to hold assets that are riskier than Treasury securities—will probably remain higher in the future than it was, on average, in the 1990–2007 period. Financial markets were already showing less appetite for risk in the early 2000s, so the risk premium was higher toward the end of that 18-year period than the average over the whole 1990–2007 period. In addition, CBO expects, the demand for low-risk assets will be stronger in the wake of the financial crisis, in part because of the ways in which financial institutions have responded to oversight from regulators.

At the same time, in CBO's assessment, the following factors will tend to increase interest rates on government securities relative to their 1990–2007 average:

- If current laws do not change, federal debt will be much larger as a percentage of GDP than it was before 2007. CBO's economic benchmark is built on the assumption that the ratio of debt to GDP after 2025 will remain at its 2025 value—78 percent—which is almost twice as high as the 40 percent average seen over the 1990–2007 period.[16] Higher federal debt tends to crowd out private investment in the long term, reducing the amount of capital per worker and increasing both the return on capital and interest rates.

- Net inflows of capital from other countries will be smaller as a percentage of GDP in the future than they have been, on average, in recent decades, CBO projects. In the 1990s and early to mid-2000s, rapid economic growth and high rates of saving in various nations with emerging market economies led to large flows of capital from those countries to the United States. As those nations' economies continue to grow, however, their consumption will probably increase relative to their saving—because markets for those countries' debt will develop and because average citizens will tend to receive more of the gains from economic growth—and their demand for domestic investment will rise. That combination of changes will reduce capital flows to the United States, decreasing domestic investment and the amount of capital per worker and increasing rates of return. (Those developments are consistent with CBO's projection that the United States' trade deficit, the gap between its imports and its exports, will be narrower in the future as a percentage of GDP than it has been for the past few decades.)

- The capital share of income—the percentage of total income that is paid to owners of capital—which has been on an upward trend for the past few decades, will remain higher than its average of recent decades, CBO projects. Although it is expected to decline somewhat over the next decade from its current, historically high level, the factors that appear to have contributed to its rise (such as technological change and globalization) are likely to persist, keeping it above the historical average. A larger share of income accruing to owners of capital will directly boost the return on capital and thus interest rates, in CBO's estimation.

- The retirement of the baby-boom generation and slower growth of the labor force will reduce the number of workers in their prime saving years relative to the number of older people drawing down their savings. The result will be a decrease in the total amount of savings available for investment (all else being equal), which will tend to reduce the amount of capital per worker and thereby push up interest rates. (CBO estimates that this effect will only partially offset the effect on savings of increased income inequality, leaving a net increase in savings available for investment.)

Other factors not listed here will have smaller—and largely offsetting—effects on interest rates on federal borrowing over the long term, CBO estimates.

CBO also relies on information from financial markets in projecting interest rates over the long term. For example, the current interest rate on 30-year Treasury bonds implies a forecast of interest rates on shorter-term securities 30 years into the future. Incorporating that information tends to reduce interest rates that CBO projects compared with rates implied by the analysis of factors described above.

Projections of Interest Rates. Although some of the factors mentioned above have received considerable attention from researchers, others have not. The effects on interest rates of the growth of the labor force and the amount of federal debt, for example, can be quantified

16. See Chapter 6 for a discussion of the ways that the budgetary policies that would be in place under the extended baseline would affect the economy in the long term.

using available data, theoretical models, and estimates from the research literature. But the extent to which other factors will affect interest rates is more difficult to quantify. For example, changes such as shifting preferences for high-risk rather than low-risk assets are not directly observable. And factors such as the distribution of income are observable, but models and empirical estimates offer little guidance for quantifying their effects on interest rates. Moreover, prices in financial markets do not definitively indicate investors' expectations about interest rates over the long term, in part because most of the government's outstanding debt securities have maturities that are much shorter than the 25-year period that is the focus of CBO's long-term projections.

With those considerable sources of uncertainty, CBO relied on its own economic models, the economics research literature, and other information to guide assessments of the influence of different factors on interest rates in the future. Nevertheless, its projections ultimately reflect CBO's judgment.

The estimates and assumptions that underlie the economic benchmark suggest that the inflation-adjusted interest rate on 10-year Treasury notes will be about 1 percentage point lower in the coming decades than its average of 3.1 percent for the 1990–2007 period. Therefore, CBO projects, the real interest rate on 10-year Treasury notes (adjusted for the rate of increase in the CPI-U) will rise in the next few years from its current, extraordinarily low level of 1.7 percent to average 2.2 percent over the 2015–2040 period.

The average interest rate on all federal debt held by the public tends to be a little lower than the rate on 10-year Treasury notes because interest rates are generally lower on shorter-term debt than on longer-term debt, and the average maturity of federal debt is expected to remain at less than 10 years. Thus, CBO projects, the average real interest rate on all federal debt held by the public (adjusted for the rate of increase in the CPI-U) will be 1.5 percent over the 2015–2040 period. (The average interest rate on all federal debt is projected to rise more slowly than the 10-year rate because only a portion of federal debt matures each year.) CBO generally uses the average interest rate on all federal debt as a discount rate when it calculates the present value of future streams of total federal revenues and outlays in its long-term projections, as it does in estimating the fiscal gap described in Chapter 1.[17]

The Social Security trust funds hold special-issue bonds that generally earn interest rates that are higher than the average interest rate on federal debt. Therefore, in projecting the balances in the trust funds and calculating the present value of future streams of revenues and outlays for those funds, CBO uses an interest rate that averages 2.2 percent from 2015 to 2040 and 2.3 percent in the later years of the projection.

Combining CBO's projections of average real interest rates with its projection of inflation as measured by the growth of the CPI-U produces estimates of average nominal interest rates. Over the 2015–2040 period, nominal rates are projected to average 4.5 percent on 10-year Treasury notes and 3.9 percent on all federal debt held by the public.

Output

In its economic benchmark, CBO projects that real GDP will grow fairly quickly over the next few years, reflecting a recovery in aggregate demand. Thereafter, real GDP is projected to grow at a pace that reflects increases in the capital stock, productivity, and the supply of labor.

Capital Stock. Over the next decade, growth in the nation's stock of capital will be driven by economic output, national saving, and international capital flows, CBO estimates. For simplicity, CBO projects that after 2025, the capital stock will expand at a pace that is sufficient to maintain a constant rate of return on capital. That projection is consistent with CBO's projection that the average real interest rate on all federal debt held by the public will be 2.0 percent in the long term (after 2029).

Productivity. Total factor productivity is projected to increase at an average annual rate of 1.3 percent from 2015 to 2040—a growth rate that is slightly slower than the average rate of 1.4 percent seen over the period since 1950. CBO expects productivity to grow more slowly in coming decades partly because increases in average educational attainment, which contribute to

17. The present value of a flow of revenues or outlays over time is a single number that expresses that flow in terms of an equivalent sum received or paid at a specific time. The present value depends on a rate of interest (known as the discount rate) that is used to translate past and future cash flows into current dollars. The lower the discount rate, the higher the present value of the future flows.

workers' skills, have slowed since 1980.[18] That effect will be partly offset, however, by the aging of the labor force over the next few decades, as better health and longer life spans cause people to stay in the workforce longer than previous cohorts did. An older workforce will be composed of more highly educated workers, because workers with higher educational attainment tend to remain in the labor force longer.

Another factor that is projected to slow the growth of total factor productivity is a lower projected amount of federal investment. Under the assumptions used for these projections, the government's nondefense discretionary spending is projected to decline over the next decade to a much smaller percentage of GDP than it has averaged in the past. Since the 1980s, about half of such spending has consisted of federal investment in physical capital (such as roads), education and training, and research and development.[19] Those forms of investment contribute to total factor productivity, CBO estimates, so as the economy adjusts to smaller amounts of federal investment (consistent with less nondefense discretionary spending as a percentage of GDP), the growth rate of total factor productivity is projected to be dampened slightly.

18. CBO calculates total factor productivity as the portion of growth in output that is not accounted for by growth in hours worked and in capital services. Therefore, when an increase in workers' skills makes each hour of work more productive, CBO measures that effect as an increase in total factor productivity. Various researchers have examined trends in workers' skills and the effect of those trends on future economic growth; that research has not reached a consensus about the size of the effect. For example, see David M. Byrne, Stephen D. Oliner, and Daniel E. Sichel, *Is the Information Technology Revolution Over?* Finance and Economics Discussion Series Paper 2013-36 (Board of Governors of the Federal Reserve System, March 2013), http://go.usa.gov/XXNR; John Fernald, *Productivity and Potential Output Before, During, and After the Great Recession*, Working Paper 2012-18 (Federal Reserve Bank of San Francisco, September 2012), http://tinyurl.com/pk8b666 (PDF, 480 MB); Robert J. Gordon, *Is U.S. Economic Growth Over? Faltering Innovation Confronts the Six Headwinds*, Policy Insight 63 (Center for Economic Policy Research, September 2012), http://tinyurl.com/p57pzt5; and Claudia Goldin and Lawrence F. Katz, *The Race Between Education and Technology: The Evolution of U.S. Educational Wage Differentials, 1890 to 2005*, Working Paper 12984 (National Bureau of Economic Research, March 2007), www.nber.org/papers/w12984.

19. See Congressional Budget Office, *Federal Investment* (December 2013), www.cbo.gov/publication/44974.

Supply of Labor. Total hours worked will increase at an average annual rate of 0.4 percent between 2015 and 2040, CBO estimates, on the basis of the projections of the size of the labor force, average hours worked, and unemployment.

The growth rates projected for the labor supply, the capital stock, and total factor productivity are consistent with CBO's projection of the average growth of labor productivity (real output per hour worked): 1.8 percent annually over the 2015–2040 period. Trends in prices, in the growth of nonwage compensation (such as employment-based health insurance), and in average hours worked imply that real earnings per worker will grow more slowly than labor productivity—by an average of 1.6 percent a year over the 2015–2025 period and by 1.4 percent a year over the 2015–2040 period.[20]

Real GDP. CBO's projection of the growth rate of real GDP—an annual average of 2.2 percent over the 2015–2040 period—is much slower than the rate of economic growth seen in the past few decades (3.1 percent), primarily because of the slowdown that CBO anticipates in the growth of the labor force. Moreover, as the fraction of the population that is of working age shrinks, per capita real GDP is expected to increase more slowly than in the past—at an average annual rate of 1.5 percent over the 2015–2040 period, compared with 2.1 percent during the 40 years before the start of the 2007–2009 recession.

Just as the unemployment rate is projected to be about one-quarter of a percentage point higher than the natural rate of unemployment in the long term, total GDP is projected to be one-half of a percent lower than its potential (maximum sustainable) amount. That projection is based on CBO's estimate that actual GDP has been roughly that much lower than potential GDP, on average, since the end of World War II and has been lower than potential GDP, on average, in each of the past five business cycles. Those outcomes reflect the fact that actual output has fallen short of CBO's estimate of potential output during and after economic downturns to

20. Trends in prices are important in projecting those measures because real earnings per worker are calculated here using the CPI-U, and real output per hour is calculated using the GDP deflator. CBO projects that the CPI-U will grow 0.4 percentage points faster per year than will the GDP deflator over the long term.

a larger extent and for longer periods than actual output has exceeded potential output during economic booms.

If the real interest rates were adjusted to reflect the rate of increase in the GDP price index instead of the CPI-U, the real interest rate on all federal debt held by the public over the next 25 years would average 1.9 percent. Thus, during the next 25 years as a whole, the growth rate of GDP—at 2.2 percent—is projected to exceed the average real interest rate on federal debt. (Beyond 2025, the average interest rate on federal debt is projected to be only slightly higher than the growth rate of GDP.) When the interest rate is about the same as the growth rate of GDP, the ratio of debt to GDP would remain steady over time if the federal budget, excluding interest payments, was in balance.

Other Trends

In addition to projecting the demographic and economic trends that underlie the economic benchmark, CBO also projects other trends as it develops its long-term budget projections. CBO has produced its own projection of the rate at which people will qualify for Social Security's Disability Insurance program in coming decades as well as projections of enrollment in Medicaid.

Disability

One variable that affects the federal budget is the rate of disability incidence, defined here as the rate at which people will become eligible for Social Security's Disability Insurance program. CBO projects that an average of 5.6 per thousand people who have worked long enough to qualify for disability benefits, but who are not yet receiving them, will qualify for the program each year after 2025. (That projection accounts for changes in the age and sex makeup of the population, relative to its composition in 2000.) CBO's estimate is based on analysis of past trends and on recommendations by the Social Security Technical Panel on Assumptions and Methods.[21]

21. See Congressional Budget Office, *The 2013 Long-Term Budget Outlook* (September 2013), p. 17, www.cbo.gov/publication/44521.

Medicaid Enrollment

To implement the formulaic approach it used to project Medicaid enrollment over the long term, CBO adopted the assumption that the number of elderly and disabled Medicaid beneficiaries would grow with the overall population, with adjustments for changes in the age distribution of the population. The agency also projected that the number of beneficiaries who are children and non-disabled adults would increase more slowly than the population overall, reflecting the assumption that growth in earnings will reduce the number of people whose income is below the most common threshold for eligibility for those groups—in many states that threshold is 138 percent of the federal poverty guidelines. Because earnings are projected to grow faster than prices, on average, and because poverty guidelines are indexed to prices, over time fewer people are projected to have income below the eligibility threshold in their state.

In the past, many states have used Medicaid's flexible program rules to increase or decrease spending in various ways. Under current law, for example, states with income eligibility criteria below 138 percent of the federal poverty guidelines for nonelderly adults can expand coverage for that group. They also can increase enrollment in the program by adopting administrative policies and procedures that simplify the enrollment process and expand program benefits by covering more optional services. (Such mechanisms also may be used to shrink program spending when states are facing fiscal constraints.) More generally, states can apply for waivers of Medicaid program requirements to enable them to change program eligibility criteria and covered benefits in other ways. (The Secretary of Health and Human Services has the authority to waive some Medicaid program requirements through certain research and demonstration projects or through consolidated State Innovation Waivers that include Medicaid-related components.) For these projections, therefore, CBO assumed that, over time, states would make changes in their Medicaid programs that offset roughly half of the effect of earnings growth on eligibility. As a result, the total number of people enrolled in Medicaid is projected to be roughly constant after 2035.

APPENDIX

B

Changes in CBO's Long-Term Projections Since July 2014

The long-term projections of federal revenues and outlays presented in this report are generally similar to the ones that the Congressional Budget Office published in 2014 despite certain changes in law, revisions to some of the agency's assumptions and methods, and the availability of more recent data.[1] Without macroeconomic feedback taken into account, debt is projected to rise from about 74 percent of gross domestic product (GDP) this year to 101 percent in 2039 under the extended baseline, whereas last year, CBO projected that debt would rise to 106 percent of GDP in 2039 (see Figure B-1). The difference stems primarily from a change in CBO's projection of the interest rates on federal debt. Under the extended alternative fiscal scenario with macroeconomic feedback, debt is projected to rise to 166 percent of GDP in 2039; last year, that figure was 183 percent.

Changes in Methods Underlying the Extended Baseline

Since last year, CBO has changed its projections of economic output and interest rates in the long term, has modified its expectations about the share of payroll that will be subject to Social Security's payroll tax, and has revised its projections of enrollment in Medicaid. Those changes, taken together, result in a projected path for debt that is slightly lower than the one last year.

Lower GDP

CBO's current projection of nominal GDP in 2039 is about 3 percent smaller than its estimate last year. Mostly, that change occurred because CBO lowered its projection of real (inflation-adjusted) GDP in the 10-year economic projections that it published in January 2015.[2] That revision derived mostly from a reduced estimate of total factor productivity (that is, the efficiency with which labor and capital are used to produce goods and services) in the first 10 years of the projection period. Because the projected growth rate of real GDP after 2025 is about the same this year as it was last year, that difference persists. CBO also reduced its projection of the rate of inflation by 0.1 percentage point.

Lower Interest Rates

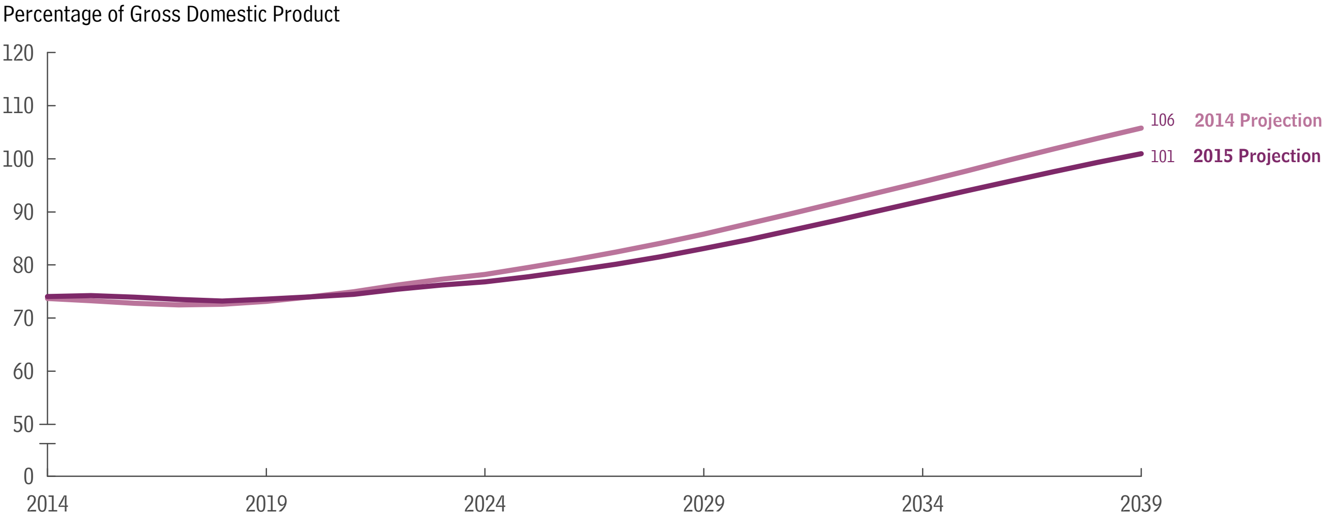
In last year's long-term analysis, the real interest rate on 10-year Treasury notes—calculated by subtracting the rate of increase in the consumer price index from the nominal yield on such notes—was projected to be 2.5 percent in the long term. CBO now projects that rate to be 2.3 percent. Similarly, last year, the projected average real interest rate on government debt was 2.2 percent, but the agency now expects it to be 2.0 percent (thus lower by the same amount). Primarily, CBO's revision to projected interest rates results from incorporating financial market participants' expectations for low interest rates well into the future. Gleaning market participants' predicted path of interest rates over the long term from prices of financial instruments is subject to enormous uncertainty because current interest rates are also influenced by transitory liquidity and risk factors that are difficult to disentangle from expectations about future interest rates. Nonetheless, a review of the results from the available models and evidence linking current rates to future rates suggests that participants in financial markets expect low interest rates well into the future, and the paths that they anticipate have fallen notably over the past year.

1. See Congressional Budget Office, *The 2014 Long-Term Budget Outlook* (July 2014), www.cbo.gov/publication/45471.

2. For further discussion, see Congressional Budget Office, *The Budget and Economic Outlook: 2015 to 2025* (January 2015), pp. 52–55, www.cbo.gov/publication/49892.

Figure B-1.

Comparison of CBO's 2014 and 2015 Projections of Federal Debt Held by the Public Under the Extended Baseline



Source: Congressional Budget Office.

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period. These projections do not reflect the macroeconomic effects of the policies underlying the extended baseline. (For an analysis of those effects and their impact on debt, see Chapter 6.)

A Lower Share of Earnings That Are Subject to the Social Security Payroll Tax

Since last year, a methodological improvement has led CBO to lower its projection of the share of earnings that are subject to the Social Security payroll tax, from an average of 82 percent to an average of 78 percent for the 2025–2039 period. Specifically, the agency has better aligned its methods for projecting revenues and its methods for projecting the earnings of workers covered by Social Security. This year, the estimated share of earnings below the taxable maximum (reported in Appendix A) for years beyond the next decade incorporates the increase in earnings inequality that underlies CBO's baseline projection of revenues over the next decade.

Lower Enrollment in Medicaid

This year, CBO has revised an assumption that affects the projected enrollment in Medicaid. Specifically, CBO now anticipates that states will take fewer actions that would maintain Medicaid spending over the long term (through such means as obtaining program waivers to expand eligibility to new population groups, enhanced outreach efforts to increase enrollment of eligible people, and expansion of covered benefits) as rising earnings over time reduce the number of people who would be eligible for the program as it is currently implemented. Last year, CBO assumed that states' actions would offset all of the effect of earnings growth on eligibility; this year, CBO assumes that those actions will offset only half of that effect. The change reduces the agency's projection of the number of Medicaid beneficiaries by an increasing amount over time and by a total of 4 percent after 25 years.

Changes in Spending and Revenues Under the Extended Baseline

In CBO's extended baseline, noninterest spending exceeds revenues throughout the next quarter century; the shortfall is similar to that projected in 2014 (see the bottom panel of Figure B-2). Interest costs on the debt are lower than last year because of lower interest rates.

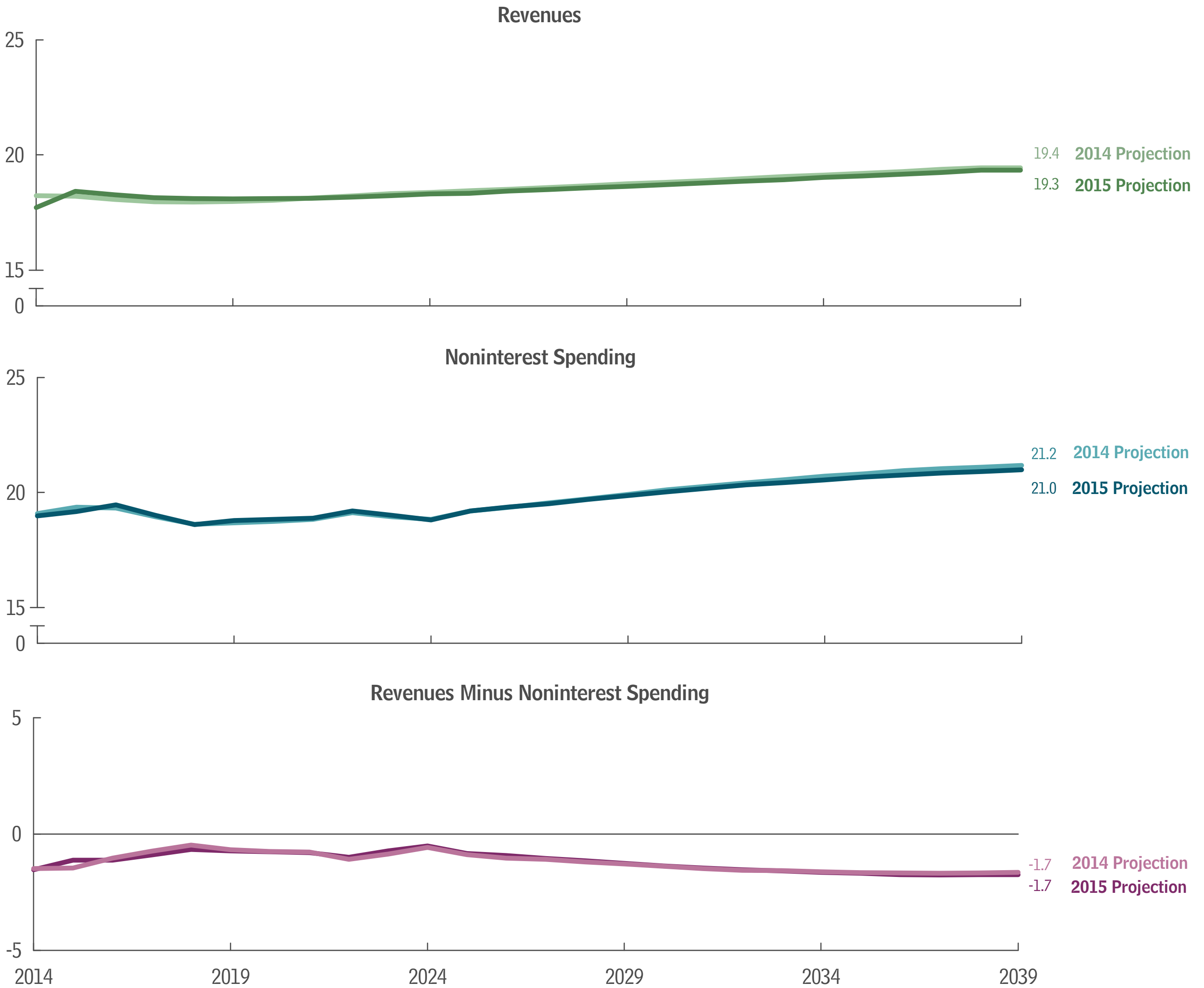
Revenues

Federal revenues are projected to be slightly lower relative to GDP in coming decades than the amounts CBO projected in 2014 (see the top panel of Figure B-2). By 2025, revenues are projected to be 18.3 percent of GDP, whereas last year, the estimate was 18.4 percent. That difference is estimated to persist in subsequent years,

Figure B-2.

Comparison of CBO's 2014 and 2015 Budget Projections Under the Extended Baseline

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

Note: The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2025 and then extending the baseline concept for the rest of the long-term projection period. These projections do not reflect the macroeconomic effects of the policies underlying the extended baseline. (For an analysis of those effects and their impact on debt, see Chapter 6.)

reflecting slightly slower growth in realizations of capital gains that are taxable and other factors. By 2039, revenues are now projected to equal 19.3 percent of GDP, or 0.1 percentage point lower than the 19.4 percent estimate last year.

Noninterest Spending

Noninterest spending is projected to be about the same relative to GDP as what CBO projected in 2014 (see the middle panel of Figure B-2). In particular, noninterest spending is projected to be slightly higher than last year's estimates for about the first decade of the projection period and then to fall below last year's estimates beginning in 2027. In 2039, it is projected to be 21.0 percent of GDP, or 0.2 percentage points lower than last year's estimate. Federal health care spending is projected to be about the same, Social Security spending lower, and other noninterest spending about the same relative to GDP compared with the amounts CBO projected last year.

Federal Health Care Spending. CBO's current long-term projection of federal spending on major health care programs is largely the same as last year's—though the growth rate of Medicare spending is faster than that projected last year, and the growth rate of the spending for Medicaid and exchange subsidies is much slower. Spending for Medicare net of offsetting receipts is now estimated to amount to 5.0 percent of GDP in 2039, or about 0.4 percentage points higher than what CBO estimated last year. That difference reflects higher projected spending for the program in the first 10 years and slightly higher estimates of the rate of excess cost growth (or growth in spending per beneficiary beyond the growth in potential output per capita) through the end of the projection period. In total, federal spending for Medicaid, the Children's Health Insurance Program, and the exchange subsidies is projected to amount to 2.8 percent of GDP in 2039, or 0.5 percentage points lower than the sum projected last year; that difference reflects less spending for Medicaid and exchange subsidies in the first 10 years, lower average excess cost growth, and lower enrollment in Medicaid after 2025.

Social Security Spending. The current 25-year projection of Social Security spending is lower as a percentage of GDP than last year's, largely because CBO projects that a smaller portion of earnings would be subject to the Social Security tax. The program's benefits are based on taxable earnings, so that a reduction in the share of taxable earnings, which would yield lower tax revenues, would also result in smaller benefits in the future. The 75-year actuarial deficit currently projected for Social Security, 4.4 percent of taxable payroll, is greater than the 4.0 percent estimated last year (see Table 3-1 on page 54). Revised projections of economic factors, primarily lower projected interest rates, account for about half of the 0.4 percentage-point increase, and revised projections of taxable payroll account for the other half. Smaller changes—arising from updated data, the effects of the one-year shift in the projection period, and estimating changes—largely offset one another.

Other Noninterest Spending. This year, total federal spending as a share of GDP on everything other than the major health care programs, Social Security, and net interest is projected to be similar throughout the next 25 years to the share CBO projected last year.

Interest Costs

Although CBO's current projection of debt held by the public expressed as a share of GDP is only slightly lower than the agency's estimate last year, interest outlays are significantly lower in this year's analysis because of lower projected interest rates and a lower projected cumulative deficit (see Figure B-1 on page 122). In this year's report, interest spending in 2039 is projected to equal 4.2 percent of GDP, whereas last year, that figure was 4.7 percent.

The Fiscal Gap

The magnitude of the changes in noninterest spending or revenues that would be needed to make federal debt equal its current percentage of GDP at a specific date in the future is often called the fiscal gap.[3] The estimated fiscal gap is slightly smaller this year than last year, largely because CBO projects lower interest rates. All else held equal, a lower interest rate leads to a smaller fiscal gap. For the 2016–2040 period, CBO estimates that cuts in noninterest spending or increases in revenues equal to 1.1 percent of GDP in each year through 2040 would be required to have debt that year equal the same percentage of GDP that it constitutes today; last year, for the 2015–2039 period, CBO estimated that changes equal to 1.2 percent of GDP would be required. By itself, the reduction in projected interest rates on federal debt would have brought the gap down by 0.3 percent of GDP, but changes in projected GDP and the shift in the projection period offset most of that effect.

Changes in Assumptions Incorporated in the Extended Alternative Fiscal Scenario

Under its extended alternative fiscal scenario last year, CBO assumed that Medicare's payment rates for services provided by physicians would be held constant at the 2014 level rather than being cut by about a quarter early in 2015, as was scheduled under current law and therefore reflected in the extended baseline. The Medicare

3. The fiscal gap equals the present value of noninterest outlays and other means of financing minus the present value of revenues over the projected period with adjustments to make the ratio of federal debt to GDP at the end of the period equal to the current ratio. Specifically, current debt is added to the present value of outlays and other means of financing, and the present value of projected debt at the end of the period (which equals GDP in the last year of the period multiplied by the ratio of debt to GDP at the end of 2015) is added to the present value of revenues.

Access and CHIP Reauthorization Act of 2015 set new rules for updating those payment rates starting in April 2015. So for that element, the extended alternative fiscal scenario and the extended baseline are now the same.

Changes in Estimated Economic Effects of Various Fiscal Policies

In this year's long-term analysis, the estimated effects on gross national product of fiscal policies that would increase or decrease future debt relative to that in the extended baseline are smaller than those in last year's analysis. Those reductions stem primarily from two factors. First, CBO reduced its projection of interest rates, so a given change in the deficit in one year cumulates to a smaller change in debt in future years and therefore has less effect on output. Second, under the extended alternative fiscal scenario, deficits excluding interest payments differ from those under the extended baseline by slightly less than they did in last year's analysis and, again, affect output less.

Changes in Methods for Analyzing Uncertainty

CBO changed its approach to analyzing the long-term budgetary effects of simultaneous changes in multiple economic factors—namely, mortality rates, growth of total factor productivity, interest rates on federal debt, and the growth rate of federal spending per beneficiary for Medicare and Medicaid (as discussed in Chapter 7). An occasion when one of those factors is at the end of the range used in the analysis of uncertainty is more likely than having all four of the factors at the end of their ranges simultaneously; so last year, adopting a rough approximation for the latter occasions, CBO narrowed those ranges by half. This year, CBO undertook more detailed analysis of the simultaneous movement in the four factors since 1967 and concluded that slightly wider ranges (60 percent as wide as the ranges applicable to individual factors in isolation) more accurately reflect the historical data.

Changes in the Presentation of Projections Beyond 25 Years

In the past, CBO included projections for years 25 years in the future in an appendix to the report, but after reassessing the considerable uncertainty surrounding projections of deficits and debt that far into the future, the agency decided to post them only as supplemental data on its website (www.cbo.gov/publication/50250).

Changes in the Presentation of Summarized Financial Measures for the Hospital Insurance Trust Fund

CBO is no longer reporting summarized financial measures, such as actuarial balances over 75 years, for Medicare's Hospital Insurance (Part A) trust fund. After reassessing those measures, the agency concluded that they do not provide meaningful information given the formulaic methodology CBO uses to project Medicare spending over the long term. Changes over time in the nature of health care and in the system for delivering health care might affect Part A and the other portions of Medicare differently, but the summarized financial measures for the Hospital Insurance trust fund that CBO previously provided did not take that possibility into account. Because CBO has yet to develop the analytic capability to project such developments, it concluded that projections for just Part A of the Medicare program were not useful.

List of Tables and Figures

Tables

Figures

Figures (Continued)

About This Document

This volume is one of a series of reports on the state of the budget and the economy that the Congressional Budget Office issues each year. In accordance with CBO's mandate to provide objective, impartial analysis, the report makes no recommendations.

Prepared with guidance from Linda Bilheimer, Wendy Edelberg, Benjamin Page, Julie Topoleski, and David Weiner, the report represents the work of many analysts at CBO. Julie Topoleski wrote the summary. Michael Simpson wrote Chapter 1. Geena Kim, Lyle Nelson, and Xiaotong Niu wrote Chapter 2. Charles Pineles-Mark wrote Chapter 3. Geena Kim wrote Chapter 4. Joshua Shakin wrote Chapter 5. Devrim Demirel wrote Chapter 6. Jonathan Huntley wrote Chapter 7. Geena Kim wrote Appendix A. Xiaotong Niu and Michael Simpson wrote Appendix B. Leigh Angres, Christina Hawley Anthony, Jessica Banthin, Elizabeth Bass, Tom Bradley, Chad Chirico, Kent Christensen, Sheila Dacey, Terry Dinan, Philip Ellis, Kathleen FitzGerald, Matthew Goldberg, Holly Harvey, Jeffrey Holland, Kim Kowalewski, Sarah Masi, Eamon Molloy, Damien Moore, Andrea Noda, Sam Papenfuss, Allison Percy, Kevin Perese, Emily Stern, Robert Stewart, and Dwayne Wright made valuable contributions.

Michael Simpson developed the long-term budget simulations, with assistance from Geena Kim, Xiaotong Niu, and Charles Pineles-Mark. Devrim Demirel, Jonathan Huntley, Leah Loversky, and Frank Russek prepared the macroeconomic simulations. David Weiner coordinated the revenue simulations, which were prepared by Paul Burnham, Ed Harris, Shannon Mok, Kurt Seibert, Joshua Shakin, Logan Timmerhoff, and Marvin Ward. Stephanie Hugie Barello, Leah Loversky, Kyle Redfield, Logan Timmerhoff, Zoe Williams, and Shiqi Zheng fact-checked the report. Also, the report builds on the 10-year projections of the economy and budget that CBO released earlier this year and that reflected the contributions of more than 100 people at the agency.

Jeffrey Kling and Robert Sunshine reviewed the report. Christine Bogusz, Kate Kelly, Loretta Lettner, Bo Peery, Benjamin Plotinsky, John Skeen, and Gabe Waggoner edited the report, and Maureen Costantino and Jeanine Rees prepared it for publication. Geena Kim, Xiaotong Niu, Charles Pineles-Mark, and Michael Simpson prepared the supplemental data, with assistance from Jeanine Rees.

The report is available on CBO's website (www.cbo.gov/publication/50250).

Keith Hall
Director

June 2015

ref2015.d021915a	2012	2013	2014	2015	2016	2017

Report Annual Energy Outlook 2015
Scenario ref2015 Reference case
Datekey d021915a
Release Date April 2015

20. Macroeconomic Indicators

(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	2012	2013	2014	2015	2016	2017
Real Gross Domestic Product	**15369**	**15710**	**16055**	**16553**	**16970**	**17369**
Components of Real Gross Domestic Product						
Real Consumption	10450	10700	10941	11270	11611	11919
Real Investment	2436	2556	2688	2851	3017	3127
Real Government Spending	2954	2894	2889	2894	2908	2927
Real Exports	1960	2020	2085	2174	2250	2340
Real Imports	2413	2440	2523	2611	2790	2918
Energy Intensity						
(thousand Btu per 2009 dollar of GDP)						
Delivered Energy	4.47	4.53	4.50	4.33	4.27	4.19
Total Energy	6.14	6.18	6.14	5.91	5.82	5.70
Price Indices						
GDP Chain-type Price Index (2009=1.000)	1.052	1.067	1.084	1.105	1.126	1.146
Consumer Price Index (1982-84=1.00)						
All-urban	2.30	2.33	2.37	2.37	2.43	2.48
Energy Commodities and Services	2.46	2.44	2.44	2.05	2.25	2.33
Wholesale Price Index (1982=1.00)						
All Commodities	2.02	2.03	2.06	2.01	2.07	2.11
Fuel and Power	2.12	2.12	2.10	1.76	1.92	1.99
Metals and Metal Products	2.20	2.14	2.16	2.21	2.25	2.28
Industrial Commodities excluding Energy	1.94	1.96	1.98	2.02	2.06	2.10
Interest Rates (percent, nominal)						
Federal Funds Rate	0.14	0.11	0.09	0.16	1.76	3.35
10-Year Treasury Note	1.80	2.35	2.57	2.86	3.75	4.21
AA Utility Bond Rate	3.83	4.24	4.20	4.30	5.78	6.54

Value of Shipments (billion 2009 dollars)						
Non-Industrial and Service Sectors	23989	24398	24943	25646	26202	26679
Total Industrial	6822	7004	7233	7598	7785	7965
Agriculture, Mining, and Construction	1813	1858	1905	2020	2106	2197
Manufacturing	5009	5146	5328	5577	5679	5768
Energy-Intensive	1675	1685	1716	1760	1791	1833
Non-Energy-Intensive	3334	3461	3612	3817	3888	3936
Total Shipments	**30810**	**31402**	**32176**	**33244**	**33986**	**34644**

Population and Employment (millions)						
Population, with Armed Forces Overseas	314.5	316.7	319.0	321.5	324.0	326.5
Population, aged 16 and over	249.2	251.5	253.7	255.9	258.2	260.4
Population, aged 65 and over	43.4	44.9	46.4	48.0	49.5	51.1
Employment, Nonfarm	133.9	136.2	138.6	141.6	143.8	145.3
Employment, Manufacturing	11.8	11.9	12.0	12.0	12.1	12.1

Key Labor Indicators						
Labor Force (millions)	155.0	155.4	155.9	157.6	159.7	161.7
Nonfarm Labor Productivity (2009=1.00)	1.05	1.05	1.06	1.08	1.10	1.12
Unemployment Rate (percent)	8.08	7.35	6.19	5.70	5.51	5.42

Key Indicators for Energy Demand						
Real Disposable Personal Income	11676	11651	11970	12361	12707	13198
Housing Starts (millions)	0.84	0.99	1.06	1.30	1.41	1.55
Commercial Floorspace (billion square feet)	82.3	82.8	83.4	84.1	84.9	85.9
Unit Sales of Light-Duty Vehicles (millions)	14.43	15.52	16.37	17.01	17.16	17.10

GDP = Gross domestic product.

Btu = British thermal unit.

- - = Not applicable.

Sources: 2012 and 2013: IHS Economics, Industry and Employment models, November 2014.

Projections: U.S. Energy Information Administration, AEO2015 National Energy Modeling System run ref2015.d021915a.

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
17835	**18296**	**18801**	**19259**	**19721**	**20221**	**20753**	**21295**	**21818**	**22344**	**22864**
12217	12520	12832	13133	13432	13762	14116	14484	14842	15202	15570
3290	3399	3531	3620	3704	3812	3915	4025	4125	4221	4298
2940	2959	2985	3005	3026	3047	3068	3098	3135	3173	3209
2484	2644	2813	2989	3179	3375	3593	3807	4009	4206	4406
3070	3201	3334	3460	3591	3743	3905	4079	4250	4410	4566
4.11	4.02	3.93	3.84	3.75	3.67	3.58	3.49	3.41	3.33	3.26
5.59	5.49	5.36	5.24	5.13	5.02	4.91	4.79	4.68	4.58	4.48
1.168	1.190	1.211	1.231	1.252	1.272	1.293	1.314	1.336	1.359	1.382
2.53	2.58	2.63	2.68	2.73	2.78	2.84	2.89	2.94	3.00	3.06
2.39	2.46	2.55	2.65	2.73	2.81	2.89	2.98	3.07	3.16	3.24
2.15	2.20	2.25	2.30	2.34	2.39	2.43	2.47	2.52	2.57	2.61
2.06	2.16	2.26	2.36	2.43	2.51	2.58	2.67	2.76	2.84	2.91
2.34	2.39	2.43	2.47	2.51	2.54	2.58	2.62	2.66	2.71	2.76
2.14	2.18	2.22	2.26	2.29	2.33	2.36	2.40	2.44	2.48	2.52
3.41	3.39	3.40	3.44	3.40	3.44	3.48	3.56	3.65	3.68	3.69
4.11	4.12	4.12	4.17	4.11	4.12	4.12	4.14	4.16	4.18	4.21
6.21	6.17	6.15	6.21	6.13	6.11	6.06	6.06	6.11	6.16	6.21

27190	27795	28468	29117	29768	30497	31290	32023	32680	33288	33866
8151	8307	8467	8585	8722	8875	9044	9212	9351	9492	9614
2260	2303	2344	2359	2373	2392	2415	2441	2467	2490	2503
5891	6004	6123	6226	6350	6483	6629	6771	6884	7001	7112
1877	1915	1946	1973	2003	2033	2060	2084	2103	2122	2141
4014	4090	4177	4253	4347	4451	4569	4687	4781	4879	4971
35342	**36101**	**36935**	**37702**	**38490**	**39373**	**40334**	**41235**	**42030**	**42780**	**43481**
329.0	331.5	334.0	336.5	339.1	341.6	344.1	346.5	349.0	351.4	353.8
262.5	264.6	266.8	268.9	271.0	273.2	275.3	277.3	279.3	281.3	283.4
52.7	54.5	56.3	58.1	59.9	61.7	63.5	65.4	67.1	68.7	70.2
146.2	147.3	148.7	149.7	150.6	151.6	152.8	153.9	154.8	155.7	156.7
11.9	11.9	11.8	11.7	11.6	11.5	11.4	11.3	11.1	11.0	10.9
163.3	164.7	165.6	166.5	167.5	168.4	169.2	169.9	170.6	171.3	172.1
1.15	1.17	1.20	1.22	1.25	1.28	1.31	1.34	1.37	1.40	1.43
5.51	5.52	5.40	5.32	5.31	5.25	5.09	4.96	4.96	4.95	4.96
13603	14008	14411	14742	15095	15489	15889	16318	16750	17205	17653
1.63	1.67	1.69	1.64	1.64	1.65	1.67	1.70	1.70	1.68	1.64
86.9	88.0	89.0	90.1	91.2	92.2	93.1	94.1	95.0	95.8	96.7
17.09	16.95	17.02	16.87	16.80	16.86	16.98	17.21	17.36	17.51	17.59

2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039

2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
23374	**23894**	**24405**	**24921**	**25480**	**26062**	**26659**	**27278**	**27908**	**28554**	**29212**
15929	16275	16620	16980	17360	17762	18179	18613	19058	19514	19988
4377	4474	4572	4649	4752	4864	4984	5112	5238	5365	5494
3245	3286	3319	3354	3389	3427	3469	3512	3556	3599	3642
4607	4815	5037	5271	5517	5765	6010	6263	6520	6786	7058
4724	4888	5066	5245	5439	5644	5859	6084	6311	6540	6782
3.20	3.13	3.07	3.01	2.95	2.89	2.83	2.77	2.72	2.67	2.62
4.39	4.31	4.22	4.14	4.05	3.97	3.90	3.82	3.75	3.68	3.61
1.406	1.431	1.458	1.485	1.513	1.540	1.569	1.598	1.629	1.661	1.695
3.12	3.18	3.25	3.32	3.39	3.46	3.54	3.61	3.69	3.77	3.86
3.33	3.42	3.53	3.65	3.78	3.90	4.03	4.17	4.32	4.49	4.67
2.66	2.71	2.77	2.83	2.89	2.96	3.02	3.08	3.15	3.22	3.31
2.99	3.08	3.19	3.31	3.44	3.56	3.69	3.83	3.97	4.15	4.35
2.80	2.85	2.91	2.96	3.02	3.08	3.13	3.19	3.25	3.30	3.36
2.57	2.61	2.66	2.71	2.76	2.81	2.85	2.90	2.95	3.01	3.06
3.68	3.69	3.67	3.67	3.69	3.73	3.76	3.79	3.85	3.92	3.99
4.23	4.28	4.31	4.33	4.37	4.40	4.41	4.42	4.46	4.52	4.58
6.26	6.33	6.38	6.42	6.44	6.47	6.47	6.47	6.52	6.58	6.65

34409	34968	35488	36007	36566	37162	37767	38387	38991	39595	40205
9731	9870	10001	10110	10255	10428	10614	10791	10957	11139	11299
2515	2540	2550	2544	2554	2576	2601	2622	2643	2667	2684
7216	7330	7451	7567	7701	7852	8012	8169	8314	8471	8615
2155	2168	2181	2193	2207	2221	2237	2252	2271	2290	2304
5060	5162	5270	5373	5494	5631	5776	5917	6043	6181	6310
44140	**44838**	**45489**	**46118**	**46820**	**47590**	**48380**	**49178**	**49948**	**50733**	**51503**
356.2	358.6	360.9	363.1	365.4	367.6	369.7	371.8	373.9	376.0	378.0
285.6	287.7	289.8	291.9	294.0	296.0	298.0	299.9	301.8	303.7	305.5
71.7	73.0	74.0	74.9	75.7	76.6	77.5	78.3	78.9	79.2	79.5
157.6	158.6	159.4	160.2	161.2	162.2	163.2	164.2	165.3	166.3	167.4
10.8	10.7	10.6	10.5	10.4	10.4	10.3	10.2	10.1	10.0	9.9
173.0	174.0	175.0	175.9	176.9	177.9	178.9	179.9	181.1	182.3	183.5
1.45	1.48	1.51	1.53	1.56	1.59	1.62	1.65	1.68	1.72	1.75
4.99	5.03	5.09	5.13	5.12	5.08	5.02	4.96	4.91	4.88	4.87
18078	18487	18881	19289	19721	20161	20610	21061	21516	21986	22462
1.64	1.66	1.65	1.60	1.60	1.61	1.62	1.62	1.63	1.63	1.61
97.5	98.4	99.2	100.1	101.1	102.1	103.2	104.4	105.6	106.8	107.9
17.60	17.54	17.45	17.43	17.47	17.56	17.68	17.80	17.91	18.02	18.10

2040

	2013-2040
2040	2040
29898	**2.4%**
20476	2.4%
5634	3.0%
3691	0.9%
7338	4.9%
7037	4.0%
2.56	-2.1%
3.54	-2.0%
1.730	1.8%
3.95	2.0%
4.85	2.6%
3.39	1.9%
4.56	2.9%
3.42	1.8%
3.12	1.7%
4.04	- -
4.63	- -
6.71	- -

40814	1.9%
11463	1.8%
2712	1.4%
8751	2.0%
2317	1.2%
6433	2.3%
52277	**1.9%**

380.0	0.7%
307.3	0.7%
79.8	2.2%
168.5	0.8%
9.7	-0.7%

184.7	0.6%
1.78	2.0%
4.85	- -

22957	2.5%
1.62	1.8%
109.1	1.0%
18.18	0.6%

Table A20. Macroeconomic indicators
(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
Real gross domestic product	**15,369**	**15,710**	**18,801**	**21,295**	**23,894**	**26,659**	**29,898**	**2.4%**
Components of real gross domestic product								
Real consumption	10,450	10,700	12,832	14,484	16,275	18,179	20,476	2.4%
Real investment	2,436	2,556	3,531	4,025	4,474	4,984	5,634	3.0%
Real government spending	2,954	2,894	2,985	3,098	3,286	3,469	3,691	0.9%
Real exports	1,960	2,020	2,813	3,807	4,815	6,010	7,338	4.9%
Real imports	2,413	2,440	3,334	4,079	4,888	5,859	7,037	4.0%
Energy intensity								
(thousand Btu per 2009 dollar of GDP)								
Delivered energy	4.47	4.53	3.93	3.49	3.13	2.83	2.56	-2.1%
Total energy	6.14	6.18	5.36	4.79	4.31	3.90	3.54	-2.0%
Price indices								
GDP chain-type price index (2009=1.000)	1.05	1.07	1.21	1.31	1.43	1.57	1.73	1.8%
Consumer price index (1982-4=1.00)								
All-urban	2.30	2.33	2.63	2.89	3.18	3.54	3.95	2.0%
Energy commodities and services	2.46	2.44	2.55	2.98	3.42	4.03	4.85	2.6%
Wholesale price index (1982=1.00)								
All commodities	2.02	2.03	2.25	2.47	2.71	3.02	3.39	1.9%
Fuel and power	2.12	2.12	2.26	2.67	3.08	3.69	4.56	2.9%
Metals and metal products	2.20	2.14	2.43	2.62	2.85	3.13	3.42	1.8%
Industrial commodities excluding energy	1.94	1.96	2.22	2.40	2.61	2.85	3.12	1.7%
Interest rates (percent, nominal)								
Federal funds rate	0.14	0.11	3.40	3.56	3.69	3.76	4.04	- -
10-year treasury note	1.80	2.35	4.12	4.14	4.28	4.41	4.63	- -
AA utility bond rate	3.83	4.24	6.15	6.06	6.33	6.47	6.71	- -
Value of shipments (billion 2009 dollars)								
Non-industrial and service sectors	23,989	24,398	28,468	32,023	34,968	37,767	40,814	1.9%
Total industrial	6,822	7,004	8,467	9,212	9,870	10,614	11,463	1.8%
Agriculture, mining, and construction	1,813	1,858	2,344	2,441	2,540	2,601	2,712	1.4%
Manufacturing	5,009	5,146	6,123	6,771	7,330	8,012	8,751	2.0%
Energy-intensive	1,675	1,685	1,946	2,084	2,168	2,237	2,317	1.2%
Non-energy-intensive	3,334	3,461	4,177	4,687	5,162	5,776	6,433	2.3%
Total shipments	**30,810**	**31,402**	**36,935**	**41,235**	**44,838**	**48,380**	**52,277**	**1.9%**
Population and employment (millions)								
Population, with armed forces overseas	315	317	334	347	359	370	380	0.7%
Population, aged 16 and over	249	251	267	277	288	298	307	0.7%
Population, aged 65 and over	43	45	56	65	73	78	80	2.2%
Employment, nonfarm	134	136	149	154	159	163	169	0.8%
Employment, manufacturing	11.8	11.9	11.8	11.3	10.7	10.3	9.7	-0.7%
Key labor indicators								
Labor force (millions)	155	155	166	170	174	179	185	0.6%
Nonfarm labor productivity (2009=1.00)	1.05	1.05	1.20	1.34	1.48	1.62	1.78	2.0%
Unemployment rate (percent)	8.08	7.35	5.40	4.96	5.03	5.02	4.85	- -
Key indicators for energy demand								
Real disposable personal income	11,676	11,651	14,411	16,318	18,487	20,610	22,957	2.5%
Housing starts (millions)	0.84	0.99	1.69	1.70	1.66	1.62	1.62	1.8%
Commercial floorspace (billion square feet)	82.3	82.8	89.0	94.1	98.4	103.2	109.1	1.0%
Unit sales of light-duty vehicles (millions)	14.4	15.5	17.0	17.2	17.5	17.7	18.2	0.6%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2012 and 2013: IHS Economics, Industry and Employment models, November 2014. **Projections:** U.S. Energy Information Administration, AEO2015 National Energy Modeling System run REF2015.D021915A.

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Annual Energy Outlook 2015

with projections to 2040

Independent Statistics & Analysis
U.S. Energy Information Administration

For further information . . .

The *Annual Energy Outlook 2015* (AEO2015) was prepared by the U.S. Energy Information Administration (EIA), under the direction of John J. Conti (john.conti@eia.gov, 202/586-2222), Assistant Administrator of Energy Analysis; Paul D. Holtberg (paul.holtberg@eia.gov, 202/586-1284), Team Leader, Analysis Integration Team, Office of Integrated and International Energy Analysis; James R. Diefenderfer (jim.diefenderfer@eia.gov, 202/586-2432), Director, Office of Electricity, Coal, Nuclear, and Renewables Analysis; Sam A. Napolitano (sam.napolitano@eia.gov, 202/586-0687), Director, Office of Integrated and International Energy Analysis; A. Michael Schaal (michael.schaal@eia.gov, 202/586-5590), Director, Office of Petroleum, Natural Gas, and Biofuels Analysis; James T. Turnure (james.turnure@eia.gov, 202/586-1762), Director, Office of Energy Consumption and Efficiency Analysis; and Lynn D. Westfall (lynn.westfall@eia.gov, 202/586-9999), Director, Office of Energy Markets and Financial Analysis.

Complimentary copies are available to certain groups, such as public and academic libraries; Federal, State, local, and foreign governments; EIA survey respondents; and the media. For further information and answers to questions, contact:

Office of Communications, EI-40
Forrestal Building, Room 2G-090
1000 Independence Avenue, S.W.
Washington, DC 20585

Telephone: 202/586-8800
(24-hour automated information line)
E-mail: infoctr@eia.gov

Fax: 202/586-0727
Website: www.eia.gov

Specific questions about the information in this report may be directed to:

General questions	Paul Holtberg (paul.holtberg@eia.gov, 202/586-1284)
National Energy Modeling System	Dan Skelly (daniel.skelly@eia.gov, 202/586-1722)
Data availability	Paul Kondis (paul.kondis@eia.gov, 202/586-1469)
Executive summary	Perry Lindstrom (perry.lindstrom@eia.gov, 202/586-0934)
Economic activity	Kay Smith (kay.smith@eia.gov, 202/586-1132)
World oil prices	Laura Singer (laura.singer@eia.gov, 202/586-4787)
International oil production	Laura Singer (laura.singer@eia.gov, 202/586-4787)
International oil demand	Linda E. Doman (linda.doman@eia.gov, 202/586-1041)
Residential demand	Kevin Jarzomski (kevin.jarzomski@eia.gov, 202/586-3208)
Commercial demand	Kevin Jarzomski (kevin.jarzomski@eia.gov, 202/586-3208)
Industrial demand	Kelly Perl (eia-oeceaindustrialteam@eia.gov, 202/586-1743)
Transportation demand	John Maples (john.maples@eia.gov, 202/586-1757)
Electricity generation, capacity	Jeff Jones (jeffrey.jones@eia.gov, 202/586-2038)
Electricity generation, emissions	Laura Martin (laura.martin@eia.gov, 202/586-1494)
Electricity prices	Lori Aniti (lori.aniti@eia.gov, 202/586-2867)
Nuclear energy	Nancy Slater-Thompson (nancy.slater-thompson@eia.gov, 202/586-9322)
Renewable energy	Gwen Bredehoeft (gwen.bredehoeft@eia.gov, 202/586-5847)
Oil and natural gas production	Terry Yen (terry.yen@eia.gov, 202/586-6185)
Wholesale natural gas markets	Katherine Teller (katherine.teller@eia.gov, 202/586-6201)
Oil refining and markets	John Powell (john.powell@eia.gov, 202/586-1814)
Ethanol and biodiesel	Anthony Radich (anthony.radich@eia.gov, 202/586-0504)
Coal supply and prices	Michael Mellish (michael.mellish@eia.gov, 202/586-2136)
Carbon dioxide emissions	Perry Lindstrom (perry.lindstrom@eia.gov, 202/586-0934)

AEO2015 is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results are available at www.eia.gov/forecasts/aeo/assumptions.

Other contributors to the report include Greg Adams, Vipin Arora, Justine Barden, Bruce Bawks, Joseph Benneche, Erin Boedecker, Michelle Bowman, Scott Bradley, Michael Bredehoeft, William Brown, Phil Budzik, Nicholas Chase, Michael Cole, Owen Comstock, Troy Cook, David Daniels, Margie Daymude, Laurie Falter, Mindi Farber-DeAnda, Faouzi Aloulou, Michael Ford, Adrian Geagla, Peter Gross, Susan Hicks, Sean Hill, Behjat Hojjati, Patricia Hutchins, Ayaka Jones, Diane Kearney, Eric Krall, Angelina LaRose, Thomas Lee, Tancred Lidderdale, Danielle Lowenthal-Savy, David Manowitz, Vishakh Mantri, Elizabeth May, Chris Namovicz, Paul Otis, Stefanie Palumbo, Jack Perrin, David Peterson, Chetha Phang, Mark Schipper, Elizabeth Sendich, John Staub, Russell Tarver, Dana Van Wagener, and Steven Wade.

Annual Energy Outlook 2015

With Projections to 2040

April 2015

U.S. Energy Information Administration
Office of Integrated and International Energy Analysis
U.S. Department of Energy
Washington, DC 20585

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Preface

The *Annual Energy Outlook 2015* (AEO2015), prepared by the U.S. Energy Information Administration (EIA), presents long-term annual projections of energy supply, demand, and prices through 2040. The projections, focused on U.S. energy markets, are based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make projections under alternative, internally-consistent sets of assumptions, the results of which are presented as cases. The analysis in AEO2015 focuses on six cases: Reference case, Low and High Economic Growth cases, Low and High Oil Price cases, and High Oil and Gas Resource case.

For the first time, the Annual Energy Outlook (AEO) is presented as a shorter edition under a newly adopted two-year release cycle. With this approach, full editions and shorter editions of the AEO will be produced in alternating years. This approach will allow EIA to focus more resources on rapidly changing energy markets both in the United States and internationally and how they might evolve over the next few years. The shorter edition of the AEO includes a more limited number of model updates, predominantly to reflect historical data updates and changes in legislation and regulation. The AEO shorter editions will include this publication, which discusses the Reference case and five alternative cases, and an accompanying *Assumptions Report*.[1] Other documentation—including documentation for each of the NEMS models and a *Retrospective Review*—will be completed only in years when the full edition of the AEO is published.

This AEO2015 report includes the following major sections:

- **Executive summary**, highlighting key results of the projections
- **Economic growth**, discussing the economic outlooks completed for each of the AEO2015 cases
- **Energy prices**, discussing trends in the markets and prices for crude oil, petroleum and other liquids,[2] natural gas, coal, and electricity for each of the AEO2015 cases
- **Delivered energy consumption by sector**, discussing energy consumption trends in the transportation, industrial, residential, and commercial sectors
- **Energy consumption by primary fuel**, discussing trends in energy consumption by fuel, including natural gas, renewables, coal, nuclear, liquid biofuels, and oil and other liquids
- **Energy intensity**, examining trends in energy use per capita, energy use per 2009 dollar of gross domestic product (GDP), and carbon dioxide (CO2) emissions per 2009 dollar of GDP
- **Energy production, imports, and exports**, examining production, import, and export trends for petroleum and other liquids, natural gas, and coal
- **Electricity generation,** discussing trends in electricity generation by fuel and prime mover for each of the AEO2015 cases
- **Energy-related CO2 emissions,** examining trends in CO2 emissions by sector and AEO2015 case.

Summary tables for the six cases are provided in Appendixes A through D. Complete tables are available in a table browser on EIA's website, at http://www.eia.gov/oiaf/aeo/tablebrowser. Appendix E provides a short discussion of the major changes adopted in AEO2015 and a brief comparison of the AEO2015 and Annual Energy Outlook 2014 results. Appendix F provides a summary of the regional formats, and Appendix G provides a summary of the energy conversion factors used in AEO2015.

The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections (for example, the proposed Clean Power Plan[3]). In certain situations, however, where it is clear that a law or a regulation will take effect shortly after AEO2015 is completed, it may be considered in the projection.

AEO2015 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

[1]U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2015*, DOE/EIA-0554(2015) (Washington, DC, to be published), http://www.eia.gov/forecasts/aeo/assumptions.

[2]Liquid fuels (or petroleum and other liquids) include crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

[3]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014), https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The AEO2015 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, and resource assumptions. The main cases in AEO2015 generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Some key uncertainties in the AEO2015 projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

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Executive summary

Projections in the *Annual Energy Outlook 2015* (AEO2015) focus on the factors expected to shape U.S. energy markets through 2040. The projections provide a basis for examination and discussion of energy market trends and serve as a starting point for analysis of potential changes in U.S. energy policies, rules, and regulations, as well as the potential role of advanced technologies.

Key results from the AEO2015 Reference and alternative cases include the following:

- The future path of crude oil and natural gas prices can vary substantially, depending on assumptions about the size of global and domestic resources, demand for petroleum products and natural gas (particularly in non-Organization for Economic Cooperation and Development (non-OECD) countries), levels of production, and supplies of other fuels. AEO2015 considers these factors in examining alternative price and resource availability cases.
- Growth in U.S. energy production—led by crude oil and natural gas—and only modest growth in demand reduces U.S. reliance on imported energy supplies. Energy imports and exports come into balance in the United States starting in 2028 in the AEO2015 Reference case and in 2019 in the High Oil Price and High Oil and Gas Resource cases. Natural gas is the dominant U.S. energy export, while liquid fuels[4] continue to be imported.
- Through 2020, strong growth in domestic crude oil production from tight formations leads to a decline in net petroleum imports[5] and growth in net petroleum product exports in all AEO2015 cases. In the High Oil and Gas Resource case, increased crude production before 2020 results in increased processed condensate[6] exports. Slowing growth in domestic production after 2020 is offset by increased vehicle fuel economy standards that limit growth in domestic demand. The net import share of crude oil and petroleum products supplied falls from 33% of total supply in 2013 to 17% of total supply in 2040 in the Reference case. The United States becomes a net exporter of petroleum and other liquids after 2020 in the High Oil Price and High Oil and Gas Resource cases because of greater U.S. crude oil production.
- The United States transitions from being a modest net importer of natural gas to a net exporter by 2017. U.S. export growth continues after 2017, with net exports in 2040 ranging from 3.0 trillion cubic feet (Tcf) in the Low Oil Price case to 13.1 Tcf in the High Oil and Gas Resource case.
- Growth in crude oil and dry natural gas production varies significantly across oil and natural gas supply regions and cases, forcing shifts in crude oil and natural gas flows between U.S. regions, and requiring investment in or realignment of pipelines and other midstream infrastructure.
- U.S. energy consumption grows at a modest rate over the AEO2015 projection period, averaging 0.3%/year from 2013 through 2040 in the Reference case. A marginal decrease in transportation sector energy consumption contrasts with growth in most other sectors. Declines in energy consumption tend to result from the adoption of more energy-efficient technologies and existing policies that promote increased energy efficiency.
- Growth in production of dry natural gas and natural gas plant liquids (NGPL) contributes to the expansion of several manufacturing industries (such as bulk chemicals and primary metals) and the increased use of NGPL feedstocks in place of petroleum-based naphtha[7] feedstocks.
- Rising long-term natural gas prices, the high capital costs of new coal and nuclear generation capacity, state-level policies, and cost reductions for renewable generation in a market characterized by relatively slow electricity demand growth favor increased use of renewables.
- Rising costs for electric power generation, transmission, and distribution, coupled with relatively slow growth of electricity demand, produce an 18% increase in the average retail price of electricity over the period from 2013 to 2040 in the AEO2015 Reference case. The AEO2015 cases do not include the proposed Clean Power Plan.[8]
- Improved efficiency in the end-use sectors and a shift away from more carbon-intensive fuels help to stabilize U.S. energy-related carbon dioxide (CO2) emissions, which remain below the 2005 level through 2040.

The future path of crude oil prices can vary substantially, depending on assumptions about the size of the resource and growth in demand, particularly in non-OECD countries

AEO2015 considers a number of factors related to the uncertainty of future crude oil prices, including changes in worldwide demand for petroleum products, crude oil production, and supplies of other liquid fuels. In all the AEO2015 cases, the North Sea

[4] Liquid fuels (or petroleum and other liquids) includes crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

[5] *Net product imports* includes trade in crude oil and petroleum products.

[6] The U.S. Department of Commerce, Bureau of Industry and Security has determined that condensate which has been processed through a distillate tower can be exported without licensing.

[7] Naphtha is a refined or semi-refined petroleum fraction used in chemical feedstocks and many other petroleum products. For a complete definition, see www.eia.gov/tools/glossary/index.cfm?id=naphtha.

[8] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014) https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Brent crude oil price reflects the world market price for light sweet crude, and all the cases account for market conditions in 2014, including the 10% decline in the average Brent spot price to $97/barrel (bbl) in 2013 dollars.

In the AEO2015 Reference case, continued growth in U.S. crude oil production contributes to a 43% decrease in the Brent crude oil price, to $56/bbl in 2015 (Figure ES1). Prices rise steadily after 2015 in response to growth in demand from countries outside the OECD; however, downward price pressure from continued increases in U.S. crude oil production keeps the Brent price below $80/bbl through 2020. U.S. crude oil production starts to decline after 2020, but increased production from non-OECD countries and from countries in the Organization of the Petroleum Exporting Countries (OPEC) contributes to the Brent price remaining below $100/bbl through 2028 and limits the Brent price increase through 2040, when it reaches $141/bbl.

There is significant price variation in the alternative cases using different assumptions. In the Low Oil Price case, the Brent price drops to $52/bbl in 2015, 7% lower than in the Reference case, and reaches $76/bbl in 2040, 47% lower than in the Reference case, largely as a result of lower non-OECD demand and higher upstream investment by OPEC. In the High Oil Price case, the Brent price increases to $122/bbl in 2015 and to $252/bbl in 2040, largely in response to significantly lower OPEC production and higher non-OECD demand. In the High Oil and Gas Resource case, assumptions about overseas demand and supply decisions do not vary from those in the Reference case, but U.S. crude oil production growth is significantly greater, resulting in lower U.S. net imports of crude oil, and causing the Brent spot price to average $129/bbl in 2040, which is 8% lower than in the Reference case.

Future natural gas prices will be influenced by a number of factors, including oil prices, resource availability, and demand for natural gas

Projections of natural gas prices are influenced by assumptions about oil prices, resource availability, and natural gas demand. In the Reference case, the Henry Hub natural gas spot price (in 2013 dollars) rises from $3.69/million British thermal units (Btu) in 2015 to $4.88/million Btu in 2020 and to $7.85/million Btu in 2040 (Figure ES2), as increased demand in domestic and international markets leads to the production of increasingly expensive resources.

In the AEO2015 alternative cases, the Henry Hub natural gas spot price is lowest in the High Oil and Gas Resource case, which assumes greater estimated ultimate recovery per well, closer well spacing, and greater gains in technological development. In the High Oil and Gas Resource case, the Henry Hub natural gas spot price falls from $3.14/million Btu in 2015 to $3.12/million Btu in 2020 (36% below the Reference case price) before rising to $4.38/million Btu in 2040 (44% below the Reference case price). Cumulative U.S. domestic dry natural gas production from 2015 to 2040 is 26% higher in the High Oil and Gas Resource case than in the Reference case and is sufficient to meet rising domestic consumption and exports—both pipeline gas and liquefied natural gas (LNG)—even as prices remain low.

Henry Hub natural gas spot prices are highest in the High Oil Price case, which assumes the same level of resource availability as the AEO2015 Reference case, but different Brent crude oil prices. The higher Brent crude oil prices in the High Oil Price case affect the level of overseas demand for U.S. LNG exports, because international LNG contracts are often linked to crude oil prices—although the linkage is expected to weaken with changing market conditions. When the Brent spot price rises in the High Oil Price case, world LNG contracts that are linked to oil prices become relatively more competitive, making LNG exports from the United States more desirable.

In the High Oil Price case, the Henry Hub natural gas spot price remains close to the Reference case price through 2020; however, higher overseas demand for U.S. LNG exports raises the average Henry Hub price to $10.63/million Btu in 2040, which is 35%

Figure ES1. North Sea Brent crude oil spot prices in four cases, 2005-40 (2013 dollars per barrel)

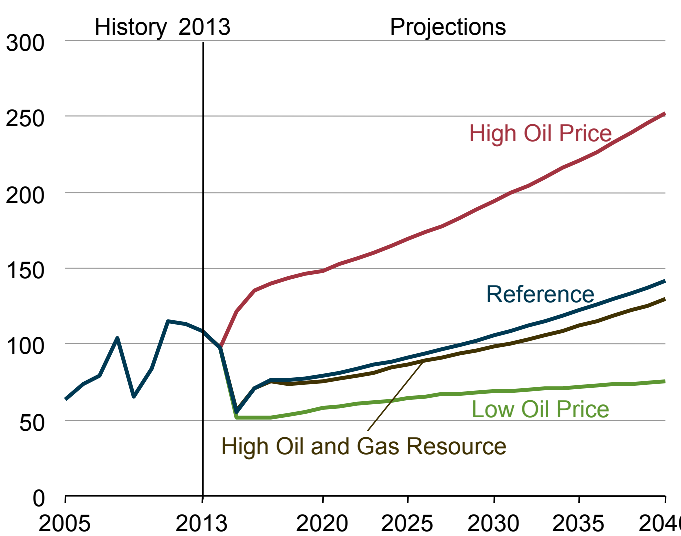
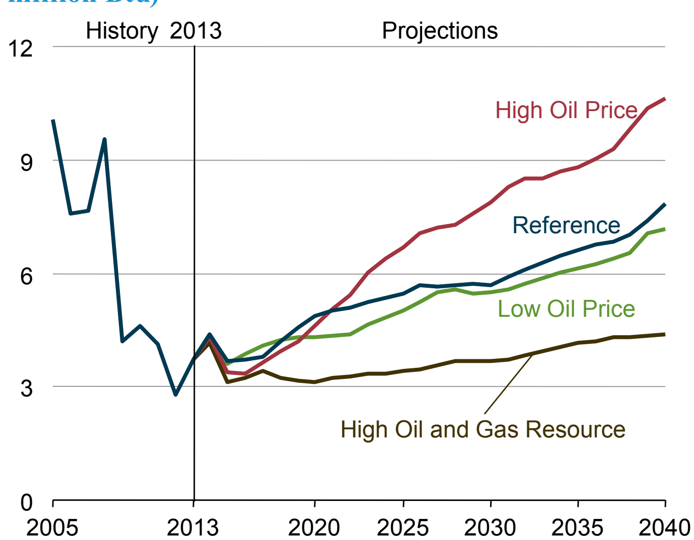


Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



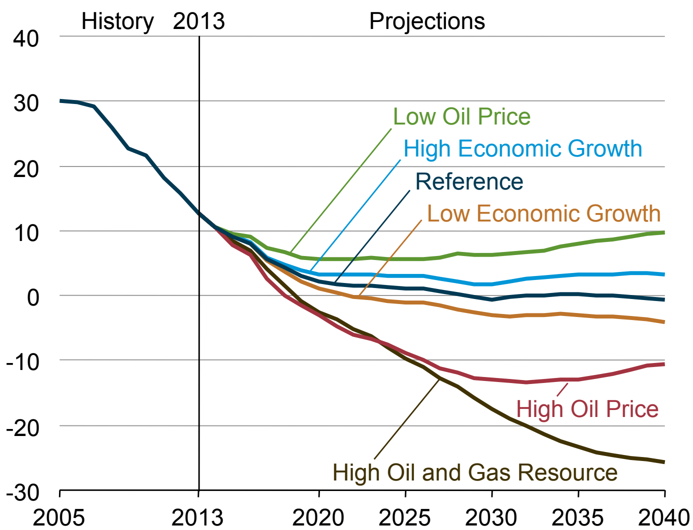
above the Reference case price. Cumulative U.S. exports of LNG from 2015 to 2040 in the High Oil Price case are more than twice those in the Reference case. The opposite occurs in the Low Oil Price case: low Brent crude oil prices cause oil-linked LNG contracts to become relatively less competitive and make U.S. LNG exports less desirable. Lower overseas demand for U.S. LNG exports causes the average Henry Hub price to reach only $7.15/million Btu in 2040, 9% lower than in the Reference case.

Global growth and trade weaken beyond 2025, creating headwinds for U.S. export-oriented industries

In the AEO2015 projections, growth in U.S. net exports contributes more to GDP growth than it has over the past 30 years (partially due to a reduction in net energy imports); however, its impact diminishes in the later years of the projection, reflecting slowing GDP growth in nations that are U.S. trading partners, along with the impacts of exchange rates and prices on trade. As economic growth in the rest of the world slows (as shown in Table ES1), so does U.S. export growth, with commensurate impacts on growth in manufacturing output, particularly in the paper, chemicals, primary metals, and other energy-intensive industries. The impact varies across industries.

Recent model revisions to the underlying industrial supply and demand relationships[9] have emphasized the importance of trade to manufacturing industries, so that the composition of trade determines the level of industrial output. Consumer goods and industrial supplies show higher levels of net export growth than other categories throughout the projection. The diminishing net export growth in all categories in the later years of the projection explains much of the leveling off of growth that occurs in some trade-sensitive industries.

Figure ES3. U.S. net energy imports in six cases, 2005-40 (quadrillion Btu)



U.S. net energy imports decline and ultimately end, largely in response to increased oil and dry natural gas production

Energy imports and exports come into balance in the United States in the AEO2015 Reference case, starting in 2028. In the High Oil Price and High Oil and Gas Resource cases, with higher U.S. crude oil and dry natural gas production and lower imports, the United States becomes a net exporter of energy in 2019. In contrast, in the Low Oil Price case, the United States remains a net energy importer through 2040 (Figure ES3).

Economic growth assumptions also affect the U.S. energy trade balance. In the Low Economic Growth case, U.S. energy imports are lower than in the Reference case, and the United States becomes a net energy exporter in 2022. In the High Economic Growth case, the United States remains a net energy importer through 2040.

The share of total U.S. energy production from crude oil and lease condensate rises from 19% in 2013 to 25% in 2040 in the High Oil and Gas Resource case, as compared with no

Table ES1. Growth of trade-related factors in the Reference case, 1983-2040 (average annual percent change)

Measure	History: 1983-2013	2013-20	2020-25	2025-30	2030-35	2035-40
U.S. GDP	2.8%	2.6%	2.5%	2.3%	2.2%	2.3%
U.S. GDP per capita	1.8%	1.8%	1.8%	1.6%	1.6%	1.8%
U.S. exports	6.1%	4.8%	6.2%	4.8%	4.5%	4.1%
U.S. imports	6.0%	4.6%	4.1%	3.7%	3.7%	3.7%
U.S. net export growth	0.1%	0.3%	2.1%	1.1%	0.8%	0.3%
Real GDP of OECD trading partners	2.4%	2.1%	1.9%	1.8%	1.7%	1.7%
Real GDP of other trading partners	4.7%	4.3%	4.2%	3.7%	3.4%	3.2%

Note: Major U.S. trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone. Other U.S. trading partners include Argentina, Brazil, Chile, Columbia, Mexico, Hong Kong, Indonesia, India, Israel, South Korea, Malaysia, Philippines, Russia, Saudi Arabia, Singapore, Thailand, Taiwan, and Venezuela.

[9]AEO2015 incorporates the U.S. Bureau of Economic Analysis (BEA) updated 2007 input-output table, released at the end of December 2013. See U.S. Department of Commerce, Bureau of Economic Analysis, "Industry Economic Accounts Information Guide (Washington, DC: December 18, 2014), http://www.bea.gov/industry/iedguide.htm#aia.

change in the Reference case. Dry natural gas production remains the largest contributor to total U.S. energy production through 2040 in all the AEO2015 cases, with a higher share in the High Oil and Gas Resource case (38%) than in the Reference case (34%) and all other cases. In 2013, dry natural gas accounted for 30% of total U.S. energy production.

Coal's share of total U.S. energy production in the High Oil and Gas Resource case falls from 26% in 2013 to 15% in 2040. In the Reference case and most of the other AEO2015 cases, the coal share remains slightly above 20% of total U.S. energy production through 2040; in the Low Oil Price case, with lower oil and gas production levels, it remains essentially flat at 23% through 2040.

Continued strong growth in domestic production of crude oil from tight formations leads to a decline in net imports of crude oil and petroleum products

U.S. crude oil production from tight formations leads the growth in total U.S. crude oil production in all the AEO2015 cases. In the Reference case, lower levels of domestic consumption of liquid fuels and higher levels of domestic production of crude oil push the net import share of crude oil and petroleum products supplied down from 33% in 2013 to 17% in 2040 (Figure ES4).

In the High Oil Price and High Oil and Gas Resource cases, growth in tight oil production results in significantly higher levels of total U.S. crude oil production than in the Reference case. Crude oil production in the High Oil and Gas Resource case increases to 16.6 million barrels per day (bbl/d) in 2040, compared with a peak of 10.6 million bbl/d in 2020 in the Reference case. In the High Oil Price case, production reaches a high of 13.0 million bbl/d in 2026, then declines to 9.9 million bbl/d in 2040 as a result of earlier resource development. In the Low Oil Price case, U.S. crude oil production totals 7.1 million bbl/d in 2040. The United States becomes a net petroleum exporter in 2021 in both the High Oil Price and High Oil and Gas Resource cases. With lower levels of domestic production and higher domestic consumption in the Low Oil Price case, the net import share of total liquid fuels supply increases to 36% of total domestic supply in 2040.

Net natural gas trade, including LNG exports, depends largely on the effects of resource levels and oil prices

In all the AEO2015 cases, the United States transitions from a net importer of 1.3 Tcf of natural gas in 2013 (5.5% of the 23.7 Tcf delivered to consumers) to a net exporter in 2017. Net exports continue to grow after 2017, to a 2040 range between 3.0 Tcf in the Low Oil Price case and 13.1 Tcf in the High Oil and Gas Resource case (Figure ES5).

In the Reference case, LNG exports reach 3.4 Tcf in 2030 and remain at that level through 2040, when they account for 46% of total U.S. natural gas exports. The growth in U.S. LNG exports is supported by differences between international and domestic natural gas prices. LNG supplied to international markets is primarily priced on the basis of world oil prices, among other factors. This results in significantly higher prices for global LNG than for domestic natural gas supply, particularly in the near term. However, the relationship between the price of international natural gas supplies and world oil prices is assumed to weaken later in the projection period, in part as a result of growth in U.S. LNG export capacity. U.S. natural gas prices are determined primarily by the availability and cost of domestic natural gas resources.

In the High Oil Price case, with higher world oil prices resulting in higher international natural gas prices, U.S. LNG exports climb to 8.1 Tcf in 2033 and account for 73% of total U.S. natural gas exports in 2040. In the High Oil and Gas Resource case, abundant U.S. dry natural gas production keeps domestic natural gas prices lower than international prices, supporting the growth of U.S. LNG exports, which total 10.3 Tcf in 2037 and account for 66% of total U.S. natural gas exports in 2040. In the Low Oil Price case,

Figure ES4. Net crude oil and petroleum product imports as a percentage of U.S. product supplied in four cases, 2005-40 (percent)

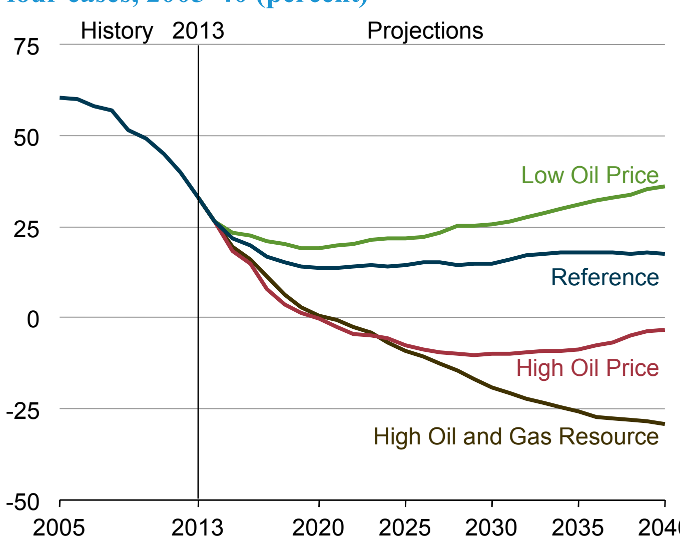
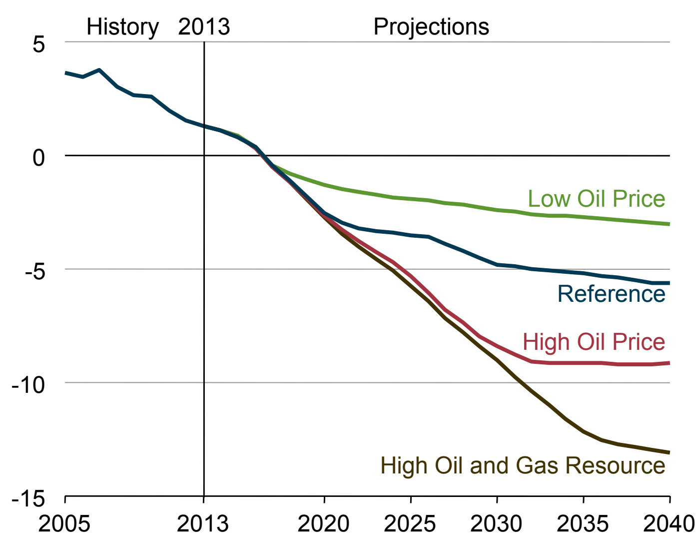


Figure ES5. U.S. total net natural gas imports in four cases, 2005-40 (trillion cubic feet)



with lower world oil prices, U.S. LNG exports are less competitive and grow more slowly, to a peak of 0.8 Tcf in 2018, and account for 13% of total U.S. natural gas exports in 2040.

Additional growth in net natural gas exports comes from growing natural gas pipeline exports to Mexico, which reach a high of 4.7 Tcf in 2040 in the High Oil and Gas Resource case (compared with 0.7 Tcf in 2013). In the High Oil Price case, U.S. natural gas pipeline exports to Mexico peak at 2.2 Tcf in 2040, as higher domestic natural gas prices resulting from increased world demand for LNG reduce the incentive to export natural gas via pipeline. Natural gas pipeline net imports from Canada remain below 2013 levels through 2040 in all the AEO2015 cases, but these imports do increase in response to higher natural gas prices in the latter part of the projection period.

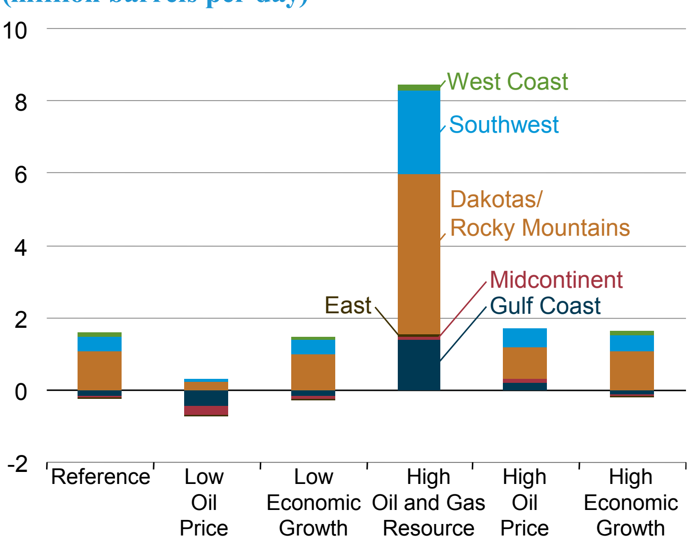
Regional variations in domestic crude oil and dry natural gas production can force significant shifts in crude oil and natural gas flows between U.S. regions, requiring investment in or realignment of pipelines and other midstream infrastructure

U.S. crude oil and dry natural gas production levels have increased rapidly in recent years. From 2008 to 2013, crude oil production grew from 5.0 million bbl/d to 7.4 million bbl/d, and annual dry natural gas production grew from 20.2 Tcf to 24.3 Tcf. All the AEO2015 cases project continued growth in U.S. dry natural gas production, whereas crude oil production continues to increase but eventually declines in all cases except the High Oil and Gas Resource case. In most of the cases, Lower 48 onshore crude oil production shows the strongest growth in the Dakotas/Rocky Mountains region (which includes the Bakken formation), followed by the Southwest region (which includes the Permian Basin) (Figure ES6). The strongest growth of dry natural gas production in the Lower 48 onshore in most of the AEO2015 cases occurs in the East region (which includes the Marcellus Shale and Utica Shale), followed by the Gulf Coast onshore region and the Dakotas/Rocky Mountains region. Interregional flows to serve downstream markets vary significantly among the different cases.

In the High Oil Price case, higher prices for crude oil and increased demand for LNG support higher levels of Lower 48 onshore crude oil and dry natural gas production than in the Reference case. Production in the High Oil Price case is exceeded only in the High Oil and Gas Resource case, where greater availability of oil and natural gas resources leads to more rapid production growth. The higher production levels in the High Oil Price and High Oil and Gas Resource cases are sustained through the entire projection period. Onshore Lower 48 crude oil production in 2040 drops below its 2013 level only in the Low Oil Price case, which also shows the lowest growth of dry natural gas production.

Crude oil imports into the East Coast and Midwest Petroleum Administration for Defense Districts (PADDs) 1 and 2 grow from 2013 to 2040 in all cases except the High Oil and Gas Resource case. All cases, including the High Oil and Gas Resource case, maintain significant crude oil imports into the Gulf Coast (PADD 3) and West Coast (PADD 5) through 2040. The Dakotas/Rocky Mountains (PADD 4) has significant crude oil imports only through 2040 in the High Oil Price case. The high levels of crude oil imports in all cases except the High Oil and Gas Resource case support growing levels of gasoline, diesel, and jet fuel exports as U.S. refineries continue to have a competitive advantage over refineries in the rest of the world. The High Oil and Gas Resource case is the only case with significant crude oil exports, which occur as a result of additional crude oil exports to Canada. The High Oil and Gas Resource case also shows significantly higher amounts of natural gas flowing out of the Mid-Atlantic and Dakotas/Rocky Mountains regions than most other cases, and higher LNG exports out of the Gulf Coast than any other case.

Figure ES6. Change in U.S. Lower 48 onshore crude oil production by region in six cases, 2013-40 (million barrels per day)



U.S. energy consumption grows at a modest rate over the projection with reductions in energy intensity resulting from improved technologies and from policies in place

U.S. energy consumption grows at a relatively modest rate over the AEO2015 projection period, averaging 0.3%/year from 2013 through 2040 in the Reference case. The transportation and residential sector's decreases in energy consumption (less than 2% over the entire projection period) contrast with growth in other sectors. The strongest energy consumption growth is projected for the industrial sector, at 0.7%/year. Declines in energy consumption tend to result from the adoption of more energy-efficient technologies and policies that promote energy efficiency. Increases tend to result from other factors, such as economic growth and the relatively low energy prices that result from an abundance of supplies.

Near-zero growth in energy consumption is a relatively recent phenomenon, and substantial uncertainty is associated with specific aspects of U.S. energy consumption in the AEO2015 projections. This uncertainty is especially relevant as the United States continues to recover from the latest economic recession and resumes more normal economic growth. Although demand for energy often grew with economic recoveries during the second half of the 20th century, technology and policy factors currently are acting in combination to dampen growth in energy consumption.

The AEO2015 alternative cases demonstrate these dynamics. The High and Low Economic Growth cases project higher and lower levels of travel demand, respectively, and of energy consumption growth, while holding policy and technology assumptions constant. In the High Economic Growth case and the High Oil and Gas Resource case, energy consumption growth (0.6%/year and 0.5%/year, respectively) is higher than in the Reference case. Energy consumption growth in the Low Economic Growth case is lower than in the Reference case (nearly flat). In the High Oil Price case, it is higher than in the Reference case, at 0.5%/year, mainly as a result of increased domestic energy production and more consumption of diesel fuel for freight transportation and trucking.

In the AEO2015 Reference case, as a result of increasingly stringent fuel economy standards, gasoline consumption in the transportation sector in 2040 is 21% lower than in 2013. In contrast, diesel fuel consumption, largely for freight transportation and trucking, grows at an average rate of 0.8%/year from 2013 to 2040, as economic growth results in more shipments of goods. Because the United States consumes more gasoline than diesel fuel, the pattern of gasoline consumption strongly influences the overall trend of energy consumption in the transportation sector (Figure ES7).

Industrial energy use rises with growth of shale gas supply

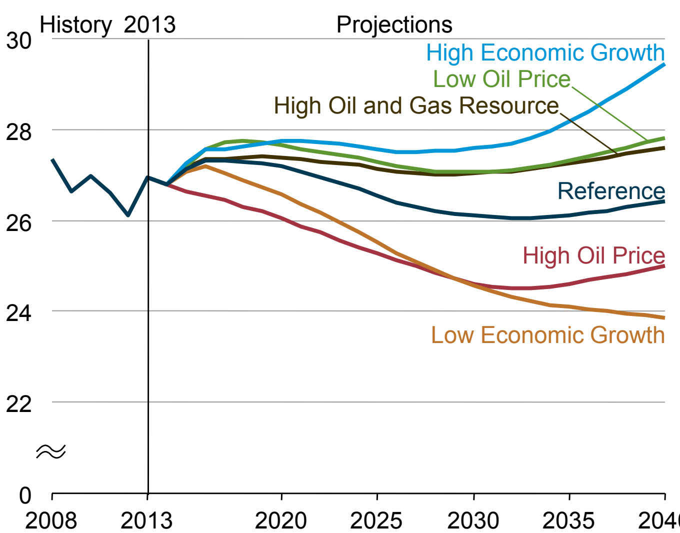
Production of dry natural gas and natural gas plant liquids (NGPL) in the United States has increased markedly over the past few years, and the upward production trend continues in the AEO2015 Reference, High Oil Price, and High Oil and Gas Resource cases, with the High Oil and Gas Resource case showing the strongest growth in production of both dry natural gas and NGPL. Sustained high levels of dry natural gas and NGPL production at prices that are attractive to industry in all three cases contribute to the growth of industrial energy consumption over the 2013-40 projection period and expand the range of fuel and feedstock choices.

Increased supply of natural gas from shale resources and the associated liquids contributes to lower prices for natural gas and hydrocarbon gas liquids (HGL), which support higher levels of industrial output. The energy-intensive bulk chemicals industry benefits from lower prices for fuel (primarily natural gas) and feedstocks (natural gas and HGL), as consumption of natural gas and HGL feedstocks increases by more than 50% from 2013 to 2040 in the Reference case, mostly as a result of growth in the total capacity of U.S. methanol, ammonia (mostly for nitrogenous fertilizers), and ethylene catalytic crackers. Increased availability of HGL leads to much slower growth in the use of heavy petroleum-based naphtha feedstocks compared to the lighter HGL feedstocks (ethane, propane, and butane). With sustained low HGL prices, the feedstock slate continues to favor HGL at unprecedented levels.

Other energy-intensive industries, such as primary metals and pulp and paper, also benefit from the availability and pricing of dry natural gas production from shale resources. However, factors other than lower natural gas and HGL prices, such as changes in nonenergy costs and export demand, also play significant roles in increasing manufacturing output.[10]

Manufacturing gross output in the High Oil and Gas Resource case is only slightly higher than in the Reference case, and most of the difference in industrial natural gas use between the two cases is attributable to the mining industry—specifically, oil and gas extraction. With increased extraction activity in the High Oil and Gas Resource case, natural gas consumption for lease and plant use in 2040 is 1.6 quadrillion Btu (68%) higher than in the Reference case.

Figure ES7. Delivered energy consumption for transportation in six cases, 2008-40 (quadrillion Btu)



Increased production of dry natural gas from shale resources (e.g., as seen in the High Oil and Gas Resource case relative to the Reference case) leads to a lower natural gas price, which leads to more natural gas use for combined heat and power (CHP) generation in the industrial sector. In 2040, natural gas use for CHP generation is 12% higher in the High Oil and Gas Resource case than in the Reference case, reflecting the higher levels of dry natural gas production. Finally, the increased supply of dry natural gas from shale resources leads to the increased use of natural gas to meet heat and power needs in the industrial sector.

Renewables meet much of the growth in electricity demand

Renewable electricity generation in the AEO2015 Reference case increases by 72% from 2013 to 2040, accounting for more than one-third of new generation capacity. The renewable share of total generation grows from 13% in 2013

[10] E. Sendich, "The Importance of Natural Gas in the Industrial Sector With a Focus on Energy-Intensive Industries," EIA Working Paper (February 28, 2014), http://www.eia.gov/workingpapers/pdf/natgas_indussector.pdf.

to 18% in 2040. Federal tax credits and state renewable portfolio standards that do not expire (sunset) continue to drive the relatively robust near-term growth of nonhydropower renewable sources, with total renewable generation increasing by 25% from 2013 to 2018. However, from 2018 through about 2030, the growth of renewable capacity moderates, as relatively slow growth of electricity demand reduces the need for new generation capacity. In addition, the combination of relatively low natural gas prices and the expiration of several key federal and state policies results in a challenging economic environment for renewables. After 2030, renewable capacity growth again accelerates, as natural gas prices increase over time and renewables become increasingly cost-competitive in some regions.

Wind and solar generation account for nearly two-thirds of the increase in total renewable generation in the AEO2015 Reference case. Solar photovoltaic (PV) technology is the fastest-growing energy source for renewable generation, at an annual average rate of 6.8%. Wind energy accounts for the largest absolute increase in renewable generation and for 40.0% of the growth in renewable generation from 2013 to 2038, displacing hydropower and becoming the largest source of renewable generation by 2040. PV capacity accounts for nearly all the growth in solar generation, split between the electric power sector and the end-use sectors (e.g., distributed or customer-sited generation). Geothermal generation grows at an average annual rate of about 5.5% over the projection period, but because geothermal resources are concentrated geographically, the growth is limited to the western United States. Biomass generation increases by an average of 3.1%/year, led by cofiring at existing coal plants through about 2030. After 2030, new dedicated biomass plants account for most of the growth in generation from biomass energy sources.

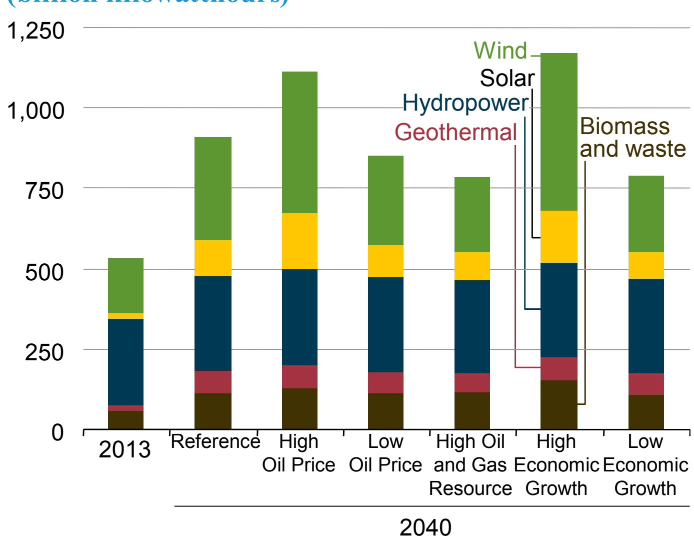
In the High Economic Growth and High Oil Price cases, renewable generation growth exceeds the levels in the Reference case—more than doubling from 2013 to 2040 in both cases (Figure ES8), primarily as a result of increased demand for new generation capacity in the High Economic Growth case and relatively more expensive competing fuel prices in the High Oil Price case. In the Low Economic Growth and Low Oil Price cases, with slower load growth and lower natural gas prices, the overall increase in renewable generation from 2013 to 2040 is somewhat smaller than in the Reference case but still grows by 49% and 61%, respectively, from 2013 to 2040. Wind and solar PV generation in the electric power sector, the sector most affected by renewable electric generation, account for most of the variation across the alternative cases in the later years of the projections.

Electricity prices increase with rising fuel costs and expenditures on electric transmission and distribution infrastructure

In the AEO2015 Reference case, increasing costs of electric power generation and transmission and distribution, coupled with relatively slow growth of electricity sales (averaging 0.7%/year), result in an 18% increase in the average retail price of electricity (in real 2013 dollars) over the projection period. In the Reference case, prices increase from 10.1 cents/kilowatthour (kWh) in 2013 to 11.8 cents/kWh in 2040. In comparison, over the same period, the largest increase in retail electricity prices (28%) is in the High Oil Price case (to 12.9 cents/kWh in 2040), and the smallest increase (2%) is in the High Oil and Gas Resource case (to 10.3 cents/kWh in 2040). Electricity prices are determined by economic conditions, efficiency of energy use, competitiveness of electricity supply, investment in new generation capacity, investment in transmission and distribution infrastructure, and the costs of operating and maintaining plants in service. Those factors vary in the alternative cases.

Fuel costs (mostly for coal and natural gas) account for the largest portion of generation costs in consumer electricity bills. In 2013, coal accounted for 44% and natural gas accounted for 42% of the total fuel costs for electricity generation. In the AEO2015 Reference case, coal accounts for 35% and natural gas for 55% of total fuel costs in 2040. Coal prices rise on average by 0.8% per year and natural gas prices by 2.4%/year in the Reference case, compared with 1.3%/year and 3.1%/year, respectively, in the High Oil Price case and 0.5%/year and 0.2%/year, respectively, in the High Oil and Gas Resource case.

Figure ES8. Total U.S. renewable generation in all sectors by fuel in six cases, 2013 and 2040 (billion kilowatthours)



There has been a fivefold increase in investment in new electricity transmission capacity in the United States since 1997, as well as large increases in spending for distribution capacity. Although investments in new transmission and distribution capacity do not continue at the same rates in AEO2015, spending continues on additional transmission and distribution capacity to connect to new renewable energy sources; improvements in the reliability and resiliency of the grid; enhancements to community aesthetics (underground lines); and smart grid construction.

The average annual rate of growth in U.S. electricity use (including sales and direct use) has slowed from 9.8% in the 1950s to 0.5% over the past decade. Factors contributing to the lower rate of growth include slower population growth, market saturation of electricity-intensive appliances, improvements in the efficiency of household appliances, and a shift in the economy toward a larger share of consumption in less energy-intensive industries. In the AEO2015 Reference case, U.S. electricity use grows by an average of 0.8%/year from 2013 to 2040.

Energy-related CO2 emissions stabilize with improvements in the energy intensity and carbon intensity of electricity generation

U.S. energy-related CO2 emissions in 2013 totaled 5,405 million metric tons (mt).[11] In the AEO2015 Reference case, CO2 emissions increase by 144 million mt (2.7%) from 2013 to 2040, to 5,549 million mt—still 444 million mt below the 2005 level of 5,993 million mt. Among the AEO2015 alternative cases, total emissions in 2040 range from a high of 5,979 million mt in the High Economic Growth case to a low of 5,160 million mt in the Low Economic Growth case.

In the Reference case:

- CO2 emissions from the electric power sector increase by an average of 0.2%/year from 2013 to 2040, as a result of relatively slow growth in electricity sales (averaging 0.7%/year) and increasing substitution of lower-carbon fuels, such as natural gas and renewable energy sources, for coal in electricity generation.
- CO2 emissions from the transportation sector decline by an average of 0.2%/year, with overall improvements in vehicle energy efficiency offsetting increased travel demand, growth in diesel consumption in freight trucks, and consumer's preference for larger, less-efficient vehicles as a result of the lower fuel prices that accompany strong growth of domestic oil and dry natural gas production.
- CO2 emissions from the industrial sector increase by an average of 0.5%/year, reflecting a resurgence of industrial activity fueled by low energy prices, particularly for natural gas and HGL feedstocks in the bulk chemical sector.
- CO2 emissions from the residential sector decline by an average of 0.2%/year, with improvements in appliance and building shell efficiencies more than offsetting growth in housing units.
- CO2 emissions from the commercial sector increase by an average of 0.3%/year even with improvements in equipment and building shell efficiency, as a result of increased electricity consumption resulting from the growing proliferation of data centers and electric devices, such as networking equipment and video displays, as well as greater use of natural gas-fueled combined heat and power distributed generation.

[11]Based on EIA, Monthly Energy Review (November 2014), and reported here for consistency with data and other calculations in the AEO2015 tables. The 2013 total was subsequently updated to 5,363 million metric tons in EIA's February 2015 Monthly Energy Review, DOE/EIA-0035(2015/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351502.pdf.

Introduction

In preparing the *Annual Energy Outlook 2015* (AEO2015)—a shorter edition; see text box on page 2—the U.S. Energy Information Administration (EIA) evaluated a range of trends and issues that could have major implications for U.S. energy markets. This report presents the AEO2015 Reference case and compares it with five alternative cases (Low and High Oil Price, Low and High Economic Growth, and High Oil and Gas Resource) that were completed as part of AEO2015 (see Appendixes A, B, C, and D).

Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets. In addition to the alternative cases prepared for AEO2015, EIA has examined many proposed policies affecting energy markets over the past few years. Reports describing the results of those analyses are available on EIA's website.[12]

Table 1 provides a summary of the six cases produced as part of AEO2015. For each case, the table gives the name used in AEO2015 and a brief description of the major assumptions underlying the projections. Regional results and other details of the projections are available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm#supplement.

Table 1. Summary of AEO2015 cases

Case name	Description
Reference	Real gross domestic product (GDP) grows at an average annual rate of 2.4% from 2013 to 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. North Sea Brent crude oil prices rise to $141/barrel (bbl) (2013 dollars) in 2040. Complete projection tables are provided in Appendix A.
Low Economic Growth	Real GDP grows at an average annual rate of 1.8% from 2013 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix B.
High Economic Growth	Real GDP grows at an average annual rate of 2.9% from 2013 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix B.
Low Oil Price	Low oil prices result from a combination of low demand for petroleum and other liquids in nations outside the Organization for Economic Cooperation and Development (non-OECD nations) and higher global supply. On the supply side, the Organization of Petroleum Exporting Countries (OPEC) increases its liquids market share from 40% in 2013 to 51% in 2040, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet (Brent) crude oil prices remain around $52/bbl (2013 dollars) through 2017, and then rise slowly to $76/bbl in 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix C.
High Oil Price	High oil prices result from a combination of higher demand for liquid fuels in non-OECD nations and lower global crude oil supply. OPEC's liquids market share averages 32% throughout the projection. Non-OPEC crude oil production expands more slowly in short- to mid-term relative to the Reference case. Brent crude oil prices rise to $252/bbl (2013 dollars) in 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix C.
High Oil and Gas Resource	Estimated ultimate recovery (EUR) per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% closer (i.e., the number of wells drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays, and the EUR for tight and shale wells increases by 1%/year more than the annual increase in the Reference case to reflect additional technology improvements. This case also includes kerogen development; undiscovered resources in the offshore Lower 48 states and Alaska; and coalbed methane and shale gas resources in Canada that are 50% higher than in the Reference case. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix D.

[12]See "Congressional and other requests," http://www.eia.gov/analysis/reports.cfm?t=138.

Changes in release cycle for EIA's *Annual Energy Outlook*

To focus more resources on rapidly changing energy markets and the ways in which they might evolve over the next few years, the U.S. Energy Information Administration (EIA) is revising the schedule and approach for production of the *Annual Energy Outlook* (AEO). Starting with this *Annual Energy Outlook 2015* (AEO2015), EIA is adopting a two-year release cycle for the AEO, with full and shorter editions of the AEO produced in alternating years. AEO2015 is a shorter edition of the AEO.

The shorter AEO includes a limited number of model updates, which are selected predominantly to reflect historical data updates and changes in legislation and regulations. A complete listing of the changes made for AEO2015 is shown in Appendix E. The shorter edition includes a Reference case and five alternative cases: Low Oil Price, High Oil Price, Low Economic Growth, High Economic Growth, and High Oil and Gas Resource.

The shorter AEO will include this publication, which discusses the Reference case and alternative cases, as well as the report, *Assumptions to the Annual Energy Outlook 2015.*[13] Other documentation—including model documentation for each of the National Energy Modeling System (NEMS) models and the *Retrospective Review*—will be completed only for the years when a full edition of the AEO is produced.

To provide a basis against which alternative cases and policies can be compared, the AEO Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the assumption that laws that include sunset dates do, in fact, expire at the time of those sunset dates). This assumption enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

Economic growth

The AEO economic forecasts are trend projections, with no major shocks assumed and with potential growth determined by the economy's supply capability. Growth in aggregate supply depends on increases in the labor force, growth of capital stocks, and improvements in productivity. Long-term demand growth depends on labor force growth, income growth, and population growth. The AEO2015 Reference case uses the U.S. Census Bureau's December 2012 middle population projection: U.S. population grows at an average annual rate of 0.7%, real GDP at 2.4%, labor force at 0.6%, and nonfarm labor productivity at 2.0% from 2013 to 2040.

Table 2. Growth in key economic factors in historical data and in the Reference case

	AEO2015 (2013-40)	Previous 30 Years
Real 2009 dollars (annual average percent change)		
GDP	2.4	2.8
GDP per capita	1.7	1.8
Disposable income	2.5	2.9
Consumer spending	2.4	3.1
Private investment	3.0	3.5
Exports	4.9	6.1
Imports	*4.0*	*6.0*
Government expenditures	*0.9*	*1.7*
GDP: Major trading countries	*1.9*	*2.4*
GDP: Other trading countries	*3.8*	*4.7*
Average annual rate		
Federal funds rate	*3.2*	*4.5*
Unemployment rate	*5.3*	*6.3*
Nonfarm business output per hour	*2.0*	*2.0*

Source: AEO2015 Reference case D021915a, based on IHS Global Insight T301114.wf1.

Table 2 compares key long-run economic growth projections in AEO2015 with actual growth rates over the past 30 years. In the AEO2015 Reference case, U.S. real GDP grows at an average annual rate of 2.4% from 2013 to 2040—a rate that is 0.4 percentage points slower than the average over the past 30 years. GDP expands in the Reference case by 3.1% in 2015, 2.5% in 2016, 2.6% from 2015 to 2025, and 2.4% from 2015 to 2040. As a share of GDP, consumption expenditures account for more than two-thirds of total GDP. In terms of growth, it is exports and business fixed investment that contribute the most to GDP. Growth in these is relatively strong during the first 10 years of the projection and then moderates for the remaining years. The growth rates for both exports and business fixed investment are above the rate of GDP growth with exports dominating throughout the projection (Figure 1).

In the AEO2015 Reference case, nominal interest rates over the 2013-40 period are generally lower than those observed for the preceding 30 years, based on an expectation of lower inflation rates in the projection period. At present, the term structure of interest rates is still at the lowest level seen over the past 40 years. In 2012, the federal funds rate averaged 0.1%. Longer-term nominal interest rates are projected to average around 6.0%, which is lower than the previous 30-year average of 7.8%. After 2015, interest rates in ensuing

[13] U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2015, DOE/EIA-0554(2015) (Washington, DC, to be published), http://www.eia.gov/forecasts/aeo/assumptions.

five-year periods through 2040 are expected to stabilize at a slightly higher level than the five-year averages through 2013, 2014, and 2015, as the result of a modest inflation rate.

Appreciation in the U.S. dollar exchange rate dampens export growth during the first five years of the projections; however, the dollar is expected to depreciate relative to the currencies of major U.S. trading partners after 2020, which combined with modest growth in unit labor costs stimulates U.S. export growth toward the end of the projection, eventually improving the U.S. current account balance. Real exports of goods and services grow at an average annual rate of 4.9%—and real imports of goods and services grow at an average annual rate of 4.0%—from 2013 to 2040 in the Reference case. The inflation rate, as measured by growth in the Consumer Price Index (CPI), averages 2.0% from 2013 to 2040 in the Reference case, compared with the average annual CPI inflation rate of 2.9% from 1983 to 2013.

Annual growth in total gross output of all goods and services, which includes both final and intermediate products, averages 1.9%/year from 2013 to 2040, with growth in the service sector (1.9%/year) just below manufacturing growth (2.0%/year) over the long term. In 2040, the manufacturing share of total gross output (17%) rises slightly above the 2013 level (16%) in the AEO2015 Reference case.

Total industrial production (which includes manufacturing, construction, agriculture, and mining) grows by 1.8%/year from 2013 to 2040 in the AEO2015 Reference case, with slower growth in key manufacturing industries, such as paper, primary metals, and aspects of chemicals excluding the plastic resin and pharmaceutical industries. Except for trade of industrial supplies, which mostly affect energy-intensive industries, net exports show weak growth until 2020. After 2020, export growth recovers as the dollar begins to depreciate and the economic growth of trading partners continues. Net export growth is strongest from the late 2020s through 2034 and declines from 2035 to 2040.

Updated information on how industries supply other industries and meet the demand of different types of GDP expenditures has influenced certain industrial projections.[14] For example, as a result of a better understanding of how the pulp and paper industry supplies other industries, trade of consumer goods and industrial supplies has a greater effect on production in the pulp and paper industry. Nonenergy-intensive manufacturing industries show higher growth than total industrial production, primarily as a result of growth in metal-based durables (Figure 2).

In the AEO2015 Reference case, manufacturing output goes through two distinct growth periods, with the clearest difference between periods seen in the energy-intensive industries. Stronger growth in U.S. manufacturing through 2025 results in part from increased shale gas production, which affects U.S. competitiveness and also results in higher GDP growth early in the projection period. In the Reference case, manufacturing output grows at an average annual rate of 2.3% from 2013 to 2025. After 2025, growth slows to 1.7% as a result of increased foreign competition and rising energy prices, with energy-intensive, trade-exposed industries showing the largest drop in growth. The energy-intensive industries grow at average rates of 1.8%/year from 2013 to 2025 and 0.7%/year from 2025 to 2040. Growth rates in the sector are uneven, with pulp and paper output decreasing at an average annual rate of 0.1% and the cement industry growing at an average annual rate of 3.1% from 2013 to 2040.

Figure 1. Annual changes in U.S. gross domestic product, business investment, and exports in the Reference case, 2015-40 (percent)

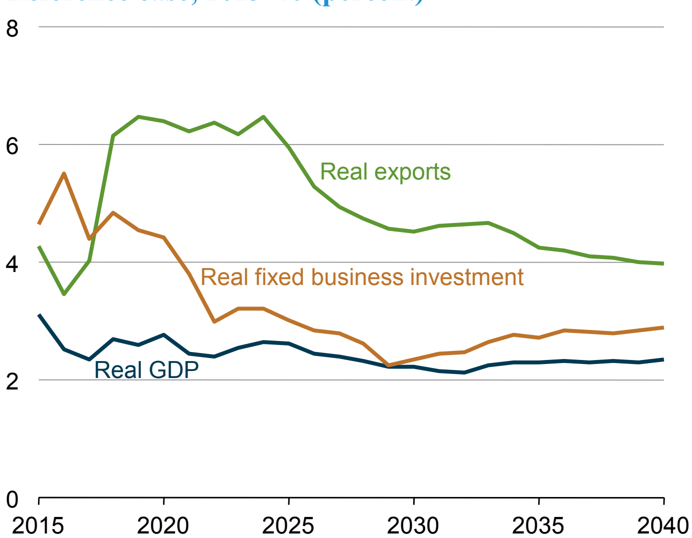
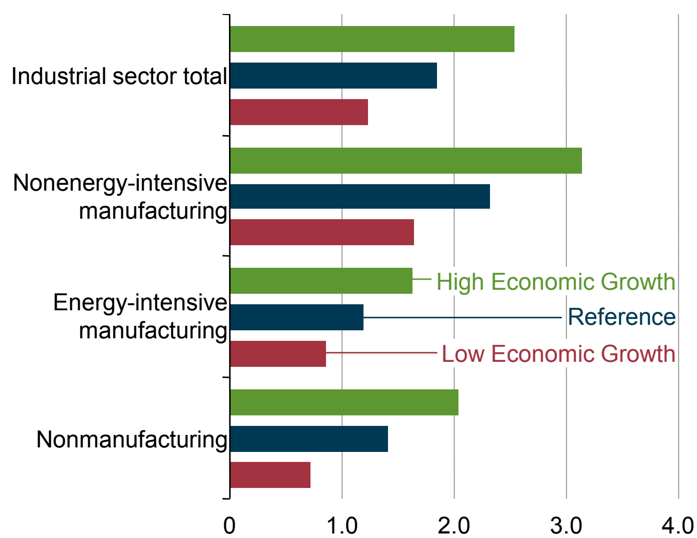


Figure 2. Annual growth rates for industrial output in three cases, 2013-40 (percent per year)



[14]The Industrial Output Model of the NEMS Macroeconomic Activity Module now uses the Bureau of Economic Analysis detailed input-output (IO) matrices for 2007 rather than 2002 (http://bea.gov/industry/io_annual.htm) and also now incorporates information from the aggregate IO matrices (http://bea.gov/industry/gdpbyind_data.htm).

AEO2015 presents three economic growth cases: Reference, High, and Low. The High Economic Growth case assumes higher growth and lower inflation, compared with the Reference case, and the Low Economic Growth case assumes lower growth and higher inflation. Differences among the Reference, High Economic Growth, and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity, which are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real GDP from 2013 to 2040 in the Reference case is 2.4%, compared with 2.9% in the High Economic Growth case and 1.8% in the Low Economic Growth case.

In the High Economic Growth case, with greater productivity gains and a larger labor force, the U.S. economy expands by 4.1% in 2015, 3.6% in 2016, 3.2% from 2015 to 2025, and 2.9% from 2015 to 2040. In the Low Economic Growth case, the current economic recovery (which is now more than five years old) stalls in the near term, and productivity and labor force growth are weak in the long term. As a result, economic growth averages 2.4% in 2015, 1.6% in 2016, 1.7% from 2015 to 2025, and 1.8% from 2015 to 2040 in the Low Economic Growth case (Table 3).

Energy prices

Crude oil

AEO2015 considers a number of factors related to the uncertainty of future world crude oil prices, including changes in worldwide demand for petroleum products, crude oil production, and supplies of other liquid fuels.[15] In the Reference, High Oil Price, and Low Oil Price cases, the North Sea Brent (Brent) crude oil price reflects the market price for light sweet crude oil free on board (FOB) at the Sullen Voe oil terminal in Scotland.

The Reference case reflects global oil market events through the end of 2014. Over the past two years, growth in U.S. crude oil production, along with the late-2014 drop in global crude oil prices, has altered the economics of the oil market. These new market conditions are assumed to continue in the Reference case, with the average Brent price dropping from $109/barrel (bbl) in 2013 to $56/bbl in 2015, before increasing to $76/bbl in 2018. After 2018, growth in demand from non-OECD countries—countries outside the Organization for Economic Cooperation and Development (OECD)—pushes the Brent price to $141/bbl in 2040 (in 2013 dollars). The increase in oil prices supports growth in domestic crude oil production.

The High Oil Price case assumes higher world demand for petroleum products, less upstream investment by the Organization of the Petroleum Exporting Countries (OPEC), and higher non-OPEC exploration and development costs. These factors all contribute to a rise in the average spot market price for Brent crude oil to $252/bbl in 2040, 78% above the Reference case. The reverse is true in the Low Oil Price case: lower non-OECD demand, higher OPEC upstream investment, and lower non-OPEC exploration

Table 3. Average annual growth of labor productivity, employment, income, and consumption in three cases (percent per year)

	2015	2016	2015-25	2015-40
Productivity				
High Economic Growth	2.3	2.3	2.4	2.3
Reference	1.9	1.6	2.1	2.0
Low Economic Growth	1.3	0.9	1.7	1.6
Non-farm employment				
High Economic Growth	2.9	1.9	1.2	0.9
Reference	2.2	1.6	0.8	0.7
Low Economic Growth	1.6	1.1	0.6	0.5
Real personal income				
High Economic Growth	3.6	3.3	3.4	2.8
Reference	3.3	2.8	2.8	2.5
Low Economic Growth	2.7	2.4	2.4	2.3
Real personal consumption				
High Economic Growth	3.6	3.5	3.2	2.9
Reference	3.0	3.0	2.5	2.4
Low Economic Growth	2.5	2.6	1.7	1.7

Source: AEO2015 Reference case D021915a, based on IHS Global Insight T301114.wf1.

[15] Liquid fuels, or petroleum and other liquids, includes crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

and development costs cause the Brent spot price to increase slowly to $76/bbl, or 47% below the price in the Reference case, in 2040 (Figure 3).

World liquid fuels consumption varies in the three cases as a result of different assumptions about future trends in oil prices, world oil supply, and the rate of non-OECD demand growth. Uncertainty about world crude oil production is also captured in the three cases. In the Reference case, world production is 99.1 million bbl/d in 2040. In comparison to the Reference case, total liquid fuel supplies and OPEC's market share are higher in the Low Oil Price case and lower in the High Oil Price case. For OPEC countries in the Middle East, Africa, and South America, combined production grows from less than 32.6 million bbl/d in 2013 to 58.3 million bbl/d in 2040 in the Low Oil Price case, compared with 43.5 million bbl/d in 2040 in the Reference case and 35.0 million bbl/d in 2040 in the High Oil Price case.

As increased OPEC production depresses world oil prices in the Low Oil Price case, development of some non-OPEC resources that are viable in the Reference case become uneconomical. As a result, non-OPEC production increases only slightly in the Low Oil Price case, from 45.3 million bbl/d in 2013 to 46.8 million bbl/d in 2040. In the High Oil Price case, non-OPEC production totals 63.8 million bbl/d in 2040. Unlike the High Oil and Gas Resource case, which assumes higher estimated ultimate recovery of crude oil and natural gas per well, closer well spacing, and greater advancement in production technology than the Reference case, the High Oil Price and Low Oil Price cases assume no changes in those factors from the Reference case.

Petroleum and other liquids products

The prices charged for petroleum products and other liquid products in the United States reflect the price that refiners pay for crude oil inputs, as well as operation, transportation, and distribution costs, and the margins that refiners receive. Changes in gasoline and distillate fuel oil prices generally move in the same direction as changes in the world crude oil price, but the changes in price are also influenced by demand factors. A 30% rise in the North Sea Brent crude oil spot price from 2013 to 2040 in the Reference case results in the weighted average U.S. petroleum product price rising by 15%, from $3.16/gallon to $3.62/gallon (in 2013 dollars). However, the effect of rising crude oil prices on distillate fuel use in the United States is less than for motor gasoline, because of a greater increase in distillate fuel demand as freight requirements continue to grow and the mix of light-duty vehicle fuels shifts from gasoline to diesel fuel. U.S. distillate fuel prices rise by 23% through 2040 in the Reference case, compared to an 11% increase for motor gasoline (Figure 4 and Figure 5). However, distillate fuel consumption rises by 15%, compared to a 20% decrease in motor gasoline consumption.

In the High Oil Price case, higher demand for crude oil in non-OECD countries and lower supply of OPEC crude oil push world crude oil prices up. As a result, the weighted average

Figure 3. North Sea Brent crude oil prices in three cases, 2005-40 (2013 dollars per barrel)

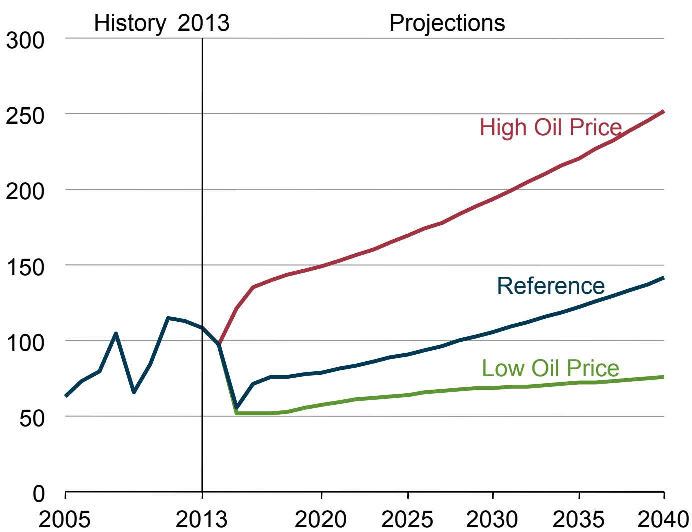


Figure 4. Motor gasoline prices in three cases, 2005-40 (2013 dollars per gallon)

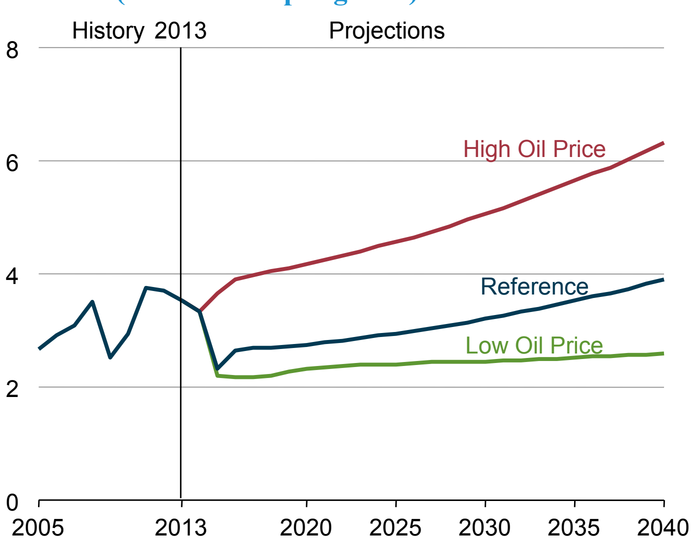
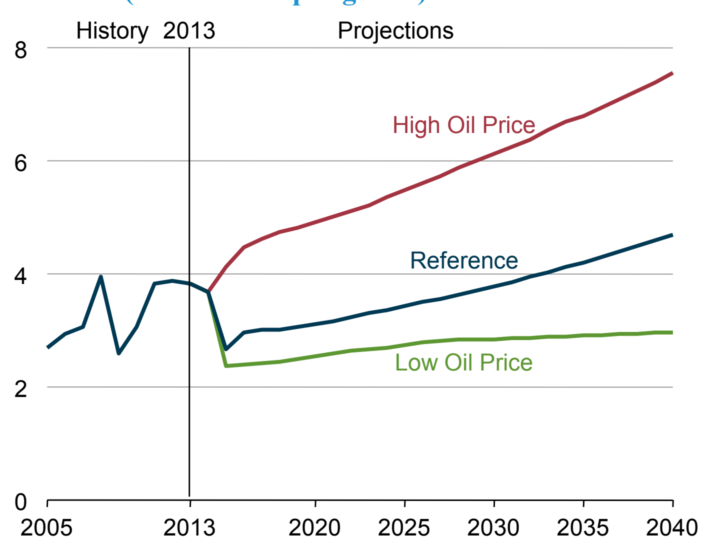


Figure 5. Distillate fuel oil prices in three cases, 2005-40 (2013 dollars per gallon)



price for U.S. petroleum products increases by 84%, from $3.16/gallon in 2013 to $5.81/gallon in 2040. In the Low Oil Price case, with lower non-OECD demand and higher OPEC supply pushing world oil prices down, the weighted average price for U.S. petroleum products drops by 26%, from $3.16/gallon in 2013 to $2.32/gallon in 2040.

In all the AEO2015 cases, U.S. laws and regulations shape demand and, consequently, the price of petroleum products in the United States. The Corporate Average Fuel Economy (CAFE) standards for new light-duty vehicles (LDVs), which typically use gasoline, rise from 30 miles per gallon (mpg) in 2013 to 54 mpg in 2040 under the fleet composition assumptions used in the final rule issued by the U.S. Environmental Protection Agency (EPA) and National Highway Transportation Safety Administration.[16] The rise in vehicle miles traveled (VMT) for LDVs does not fully offset the increase in fuel efficiency, and motor gasoline consumption declines through 2040 in all the AEO2015 cases. However, the effect of the standards varies by case because of the use of different assumptions about prices and economic growth. The 32% decrease in motor gasoline consumption in the High Oil Price case is larger than the decrease in the Reference case because higher gasoline prices reduce VMT, reducing consumption. In the Low Oil Price case, the decrease in gasoline consumption (11%) is smaller than in the Reference case because lower gasoline prices stimulate enough increased VMT to offset a part of the impact of fuel efficiency improvements resulting from regulation.

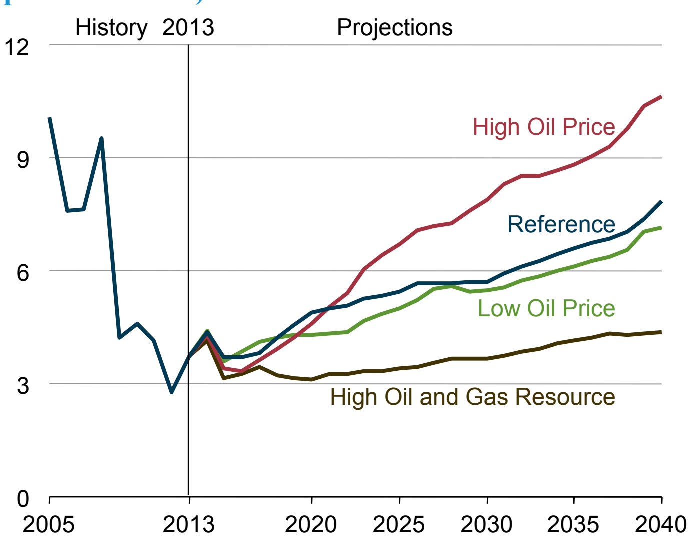
The efficiency and greenhouse gas (GHG) standard for heavy-duty vehicles, which typically consume distillate fuel, rises by about 16% through 2040, remaining below 8 mpg in all AEO2015 cases. Unlike the case for LDVs, the higher VMT in the Low Oil Price case more than offsets the increase in vehicle fuel efficiency, and distillate fuel consumption increases by 21% from 2013 to 2040. The increase in fuel consumption in the Low Oil Price case is greater than in the Reference case as a result of a 22% decrease in distillate fuel prices, to $2.97/gallon in 2040. In the High Oil Price case, the price of distillate fuel oil increases to $7.55/gallon in 2040—61% higher than in the Reference case—resulting in a 2% decline in distillate fuel consumption.

Natural gas

Henry Hub natural gas spot prices vary according to assumptions about the availability of domestically produced natural gas resources, overseas demand for U.S. liquefied natural gas (LNG), and trends in domestic consumption. In all cases, prices are lower in 2015 than the $3.73/million British thermal units (Btu) average Henry Hub spot price in 2013, and in most cases they are above that level by 2020 (Figure 6). In the AEO2015 Reference case, the Henry Hub spot price is $4.88/million Btu (2013 dollars) in 2020 and $7.85/million Btu in 2040, as increased demand in domestic and international markets requires an increased number of well completions to achieve higher levels of production. In addition, lower cost resources generally are expected to be produced earlier, with more expensive production occurring later in the projection period.

In the High Oil and Gas Resource case, U.S. domestic production from tight oil and natural gas formations is higher than in the Reference case as a result of assumed greater estimated ultimate recovery (EUR) per well, closer well spacing, and greater gains in technological development. Consequently, even with low natural gas prices, total U.S. domestic dry natural gas production grows sufficiently to satisfy higher levels of domestic consumption, as well as higher pipeline and LNG exports. With the abundance of natural gas produced domestically, the Henry Hub spot price (in 2013 dollars) falls from $3.14/million Btu in 2015 to $3.12/million Btu in 2020 (36% below the Reference case price) before rising to $4.38/million Btu in 2040 (44% below the Reference case price).

Figure 6. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



The Low and High Oil Price cases assume the same level of resource availability as the Reference case but different world oil prices, which affect the level of overseas demand for U.S. LNG exports. International LNG contracts are often linked to crude oil prices, even though their relationship may be weakening. Global demand for LNG is also directly influenced by oil prices, as LNG competes directly with petroleum products in many applications. When the North Sea Brent spot price, which is the principal benchmark price for crude oil on world markets, rises in the High Oil Price case, world LNG contracts linked to oil prices become more expensive, making LNG exports from the United States more desirable.

In the High Oil Price case, the Henry Hub natural gas spot price remains close to the Reference case price through 2020. However, higher overseas demand for U.S. LNG exports raises the average Henry Hub spot price to $10.63/million Btu in 2040, which is 35% above the Reference case price.

[16]U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC, October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.

In the Low Oil Price case, with lower demand for U.S. LNG exports, the Henry Hub spot price is only $7.15/million Btu in 2040—which is 9% lower than in the Reference case but 63% higher than in the High Oil and Gas Resource case.

Changes in the Henry Hub natural gas spot price generally translate to changes in the price of natural gas delivered to end users. The delivered price of natural gas to the electric power sector is highest in the High Oil Price case, where it rises from $4.40/million Btu in 2013 to $10.08/million Btu in 2040, compared with $8.28/million Btu in the Reference case. Higher delivered natural gas prices result in a decline in natural gas consumption in the electric power sector in the High Oil Price case, from 8.2 Tcf in 2013 to 6.8 Tcf in 2040, compared with an increase in natural gas consumption in the electric power sector to 9.4 Tcf in 2040 in the Reference case. In the Low Oil Price and High Oil and Gas Resource cases, smaller increases in delivered natural gas prices result in more consumption for power generation than in the Reference case or High Oil Price case in 2040.

As in the electric power sector, natural gas consumption in the U.S. industrial sector also changes in response to delivered natural gas prices. However, industrial natural gas consumption also changes in response to shifts in the mix of industrial output, as well as changes in refinery output and utilization. Consumption also varies with the relative economics of using natural gas for electricity generation in industrial combined heat and power (CHP) facilities. The largest increase in the price of natural gas delivered to the industrial sector, from $4.56/million Btu in 2013 to $11.03/million Btu in 2040, is seen in the High Oil Price case, followed by the Reference case ($8.78/million Btu in 2040), Low Oil Price case ($8.25/million Btu in 2040), and High Oil and Gas Resource case ($5.22/million Btu in 2040). Of those four cases, the largest increase in industrial natural gas consumption occurs in the High Oil and Gas Resource case, in which lower prices contribute to higher consumption. The next largest increase occurs in the High Oil Price case, where higher prices spur a significant increase in U.S. crude oil production and, accordingly, natural gas consumption at U.S. oil refineries.[17]

The price of natural gas delivered to the residential and commercial sectors increases from 2013 to 2040 in all the AEO2015 cases. The largest increase in delivered natural gas prices to both sectors through 2040 is in the High Oil Price case, followed by the Reference, Low Oil Price, and High Oil and Gas Resource cases. In the commercial sector, natural gas consumption increases in all cases, mainly as a result of increased commercial CHP use and growth in aggregate commercial square footage. Conversely, consumption in the residential sector decreases in all cases despite economic growth, as overall demand is reduced by population shifts to warmer areas, improvements in appliance efficiency, and increased use of electricity for home heating.

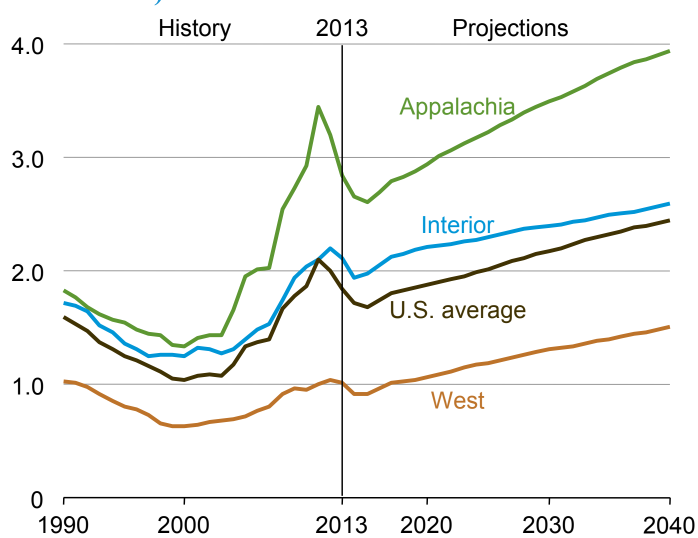
Coal

The average minemouth coal price increases by 1.0%/year in the AEO2015 Reference case, from $1.84/million Btu in 2013 to $2.44/million Btu in 2040. Higher prices result primarily from declines in coal mining productivity in several key supply regions, including Central Appalachia and Wyoming's Powder River Basin.

Across the AEO2015 alternative cases, the most significant changes in the average minemouth coal price compared with the Reference case occur in the Low and High Oil Price cases. In 2040, the average minemouth price is 6% lower in the Low Oil Price case and 7% higher in the High Oil Price case than in the Reference case. These variations from the Reference case are primarily the result of differences in the projections for diesel fuel and electricity prices in the Low and High Oil Price cases, because diesel fuel and electricity are key inputs to the coal mining process. The AEO2015 cases do not include the EPA's proposed Clean Power Plan,[18] which if implemented would likely have a substantial impact on coal use for power generation and coal markets more generally.

Increases in minemouth coal prices (in dollars/million Btu) occur in all coal-producing regions (Figure 7). In Appalachia and in the West, increases of 1.2%/year and 1.5%/year between 2013 and 2040, respectively, are primarily the result of continuing declines in coal mining productivity. In the Interior region, a more optimistic outlook for coal mining productivity, combined with substantially higher production quantities, results in slower average price growth of 0.8%/year from 2013 to 2040. Increased output from large, highly productive longwall mines in the Interior region support labor productivity gains averaging 0.3%/year over the same period.

Figure 7. Average minemouth coal prices by region in the Reference case, 1990-2040 (2013 dollars per million Btu)



[17]While not discussed in this section, the High Economic Growth case has higher levels of industrial natural gas consumption through 2040 than any of the four cases mentioned, in response to higher demand that results from significantly higher levels of industrial output.

[18]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014) https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

The average delivered price of coal (the sum of minemouth and coal transportation costs) increases at a similar, but slightly slower pace of 0.8%/year than minemouth prices, with prices rising from $2.50/million Btu in 2013 to $3.09/million Btu in 2040 in the AEO2015 Reference case (Figure 8). A relatively flat outlook for coal transportation rates results in a slightly lower growth rate for the average delivered price of coal.

Electricity

The average retail price of electricity in real 2013 dollars increases in the AEO2015 Reference case by 18% from 2013 to 2040 as a result of rising costs for power generation and delivery, coupled with relatively slow growth in electricity demand (0.7%/year on average). Electricity prices are determined by a complex set of factors that include economic conditions; energy use and efficiency; the competitiveness of electricity supply; investment in new generation, transmission, and distribution capacity; and the fuel, operation, and maintenance costs of plants in service. Figure 9 illustrates effects on retail electricity prices in the AEO2015 Reference and alternative cases resulting from different assumptions about the factors determining prices.

In the AEO2015 Reference case, average retail electricity prices (2013 dollars) increase by an average of 0.6%/year, from 10.1 cents/kilowatthour (kWh) in 2013 to 11.8 cents/kWh in 2040, an overall increase of 18%. The High Oil Price case shows the largest overall average price increase, at 28%, to 12.9 cents/kWh in 2040. The High Oil and Gas Resource case shows the smallest average increase, at 2%, to 10.3 cents/kWh in 2040. With more fuel resources available to meet demand from power producers in the High Oil and Gas Resource case, lower fuel prices lead to lower generation costs and lower retail electricity prices for consumers. In the High Economic Growth case, stronger economic growth increases demand for electricity, putting price pressure on the fuel costs and the construction cost of new generating plants. In the Low Economic Growth case, weaker growth results in lower electricity demand and associated costs.

The average annual growth in electricity use (including sales and direct use) in the United States has slowed from 9.8%/year in the 1950s to 0.5%/year over the past decade. Contributing factors include slowing population growth, market saturation of major electricity-using appliances, efficiency improvements in appliances, and a shift in the economy toward a larger share of consumption in less energy-intensive industries. In the AEO2015 Reference case, U.S. electricity use grows by 0.8%/year on average from 2013 to 2040.

Combined electricity demand in the residential and commercial sectors made up over 70% of total electricity demand in 2013, with each sector using roughly the same amount of electricity. From 2013 to 2040, residential and commercial electricity prices increase by 19% and 16%, respectively, in the Reference case; by 30% and 27% in the High Oil Price case; and by 5% and 0% in the High Oil and Gas Resource case. These variations largely reflect the importance of natural gas prices to electricity prices.

Industrial electricity prices grow by 22% in the Reference case, from 6.9 cents/kWh in 2013 to 8.4 cents/kWh in 2040. Among the alternative cases, growth in industrial electricity prices ranges from 35% (9.3 cents/kWh in 2040) in the High Oil Price case to 2% (7.1 cents/KWh in 2040) in the High Oil and Gas Resource case. In the industrial sector, electricity use increases in most industries but falls throughout the projection period for the energy-intensive refining and paper industries and, after 2024, in the aluminum, bulk chemical, and mining industries.

Retail electricity prices include generation, transmission, and distribution components. In the AEO2015 cases, about two-thirds of the retail price of electricity (between 59% and 67%) is attributable to the price of generation, which includes generation costs and retail taxes, with the remaining portion attributable to transmission and distribution costs. The generation price increases by 0.5% annually in the Reference case, from 6.6 cents/kWh in 2013 to 7.6 cents/kWh in 2040. In the High Oil Price Case, the price

Figure 8. Average delivered coal prices in six cases, 1990-2040 (2013 dollars per million Btu)

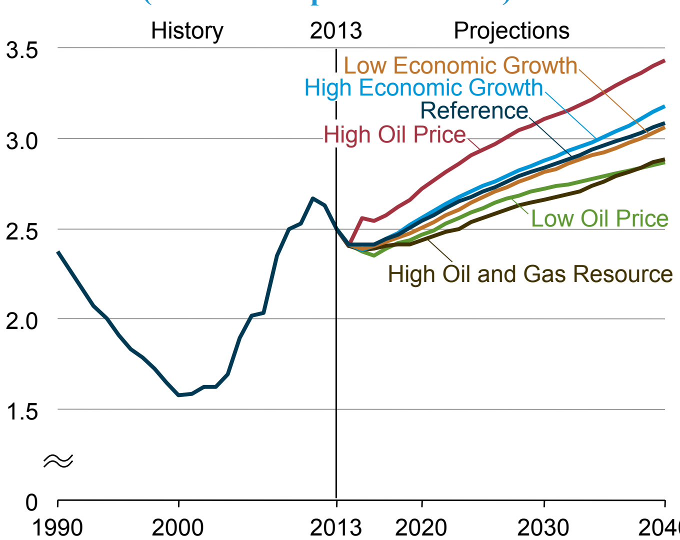
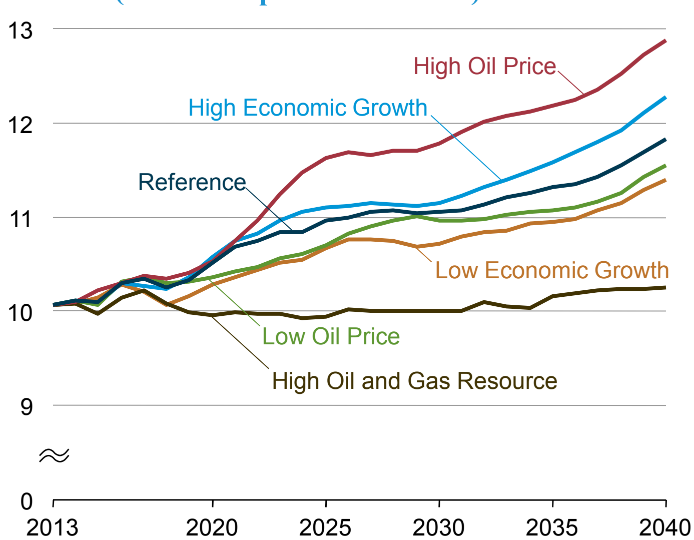


Figure 9. Average retail electricity prices in six cases, 2013-40 (2013 cents per kilowatthour)



of generation increases by 1%/year to 8.6 cents/kWh in 2040; and in the High Oil and Gas Resource Case, it falls by 0.3%/year to 6.1 cents/kWh in 2040.

Generation prices are determined differently in states with regulated and competitive electricity supplies. The AEO2015 Reference case assumes that 67% of electricity sales are subject to regulated average-cost pricing and 33% are priced competitively, based on the marginal cost of energy. In fully regulated regions, the price of generation is determined by both fixed costs (such as the costs of paying off electricity plant construction and fixed operation and maintenance costs) and variable costs (fuel and variable operation and maintenance costs).

In the Reference case, new generation capacity added through the projection period includes 144 GW of natural gas capacity, 77 GW of renewable capacity (45% is wind and 44% solar), 9 GW of nuclear capacity, and 1 GW of coal-fired capacity. Significant variation in the mix of generation capacity types added in the different AEO2015 cases also affects generation prices. Natural gas capacity additions vary substantially, with only 117 GW added in the Low Economic Growth case and 236 GW added in the High Economic Growth case. In the High Economic Growth case, a more vibrant economy leads to more industrial and commercial activity, more consumer demand for electric devices and appliances, and consequently greater demand for electricity.

Renewable generation capacity additions vary the most, with 66 GW added in the High Oil and Gas Resource case, but 194 GW added in the High Economic Growth case. Only 6 GW of new nuclear capacity is built in the Low Economic Growth and High Oil and Gas Resource cases, but 22 GW of new nuclear capacity is added in the High Oil Price case where natural gas prices are significantly above those in the Reference case. Across all the AEO2015 cases, very little new coal-fired capacity—and no new oil-fired capacity—is built through 2040.

Most generating fuel costs are attributed to coal and natural gas. In 2013, coal made up 44% of total generation fuel costs, and natural gas made up 42%. In 2040, coal makes up only 35% of total fuel costs in the Reference case, compared with 55% for natural gas. Oil, which is the most expensive fuel for generation, accounted for 6% of the total generating fuel costs in 2013 and from 2019 through 2040 accounts for only 3% of the total. Nuclear fuel accounts for 6% to 8% of electricity generation fuel costs throughout the projection period.

In regions with competitive wholesale electricity markets, the generation price generally follows the natural gas price. The price of electricity in wholesale markets is determined by the marginal cost of energy—the cost of serving the next increment of demand for a determined time period. Natural gas fuels the marginal generators during most peak and some off-peak periods in many regions.

There has been a fivefold increase in investment in new electricity transmission capacity since 1997, as well as large increases in spending for distribution capacity. Since 1997, roughly $107 billion has been spent on new transmission infrastructure and $318 billion on new distribution infrastructure, both in 2013 dollars. Those investments are paid off gradually over the projection period.

Although investment in new transmission and distribution capacity does not continue in the AEO2015 Reference case at the pace seen in recent years, spending still occurs at a rate greater than that needed to keep up with demand driven by requirements for additional transmission and distribution capacity to interconnect with new renewable energy sources, grid reliability and resiliency improvements, community aesthetics (including burying lines), and smart grid construction. In the AEO2015 Reference case, the transmission portion of the price of electricity increases by 1.2%/year, from 0.9 cents/kWh in 2013 to 1.3 cents/kWh in 2040. The distribution portion of the electricity price increases by 0.6%/year over the projection period, from 2.6 cents/kWh in 2013 to 3.0 cents/kWh in 2040. The investments in distribution capacity are undertaken mainly to serve residential and commercial customers. As a result, residential and commercial customers typically pay significantly higher distribution charges per kilowatthour than those paid by industrial customers.

Delivered energy consumption by sector

Transportation

Energy consumption in the transportation sector declines in the AEO2015 Reference case from 27.0 quadrillion Btu (13.8 million bbl/d) in 2013 to 26.4 quadrillion Btu (13.5 million bbl/d) in 2040. Energy consumption falls most rapidly through 2030, primarily as a result of improvement in light-duty vehicle (LDV) fuel economy with the implementation of corporate average fuel economy (CAFE) standards and greenhouse gas emissions (GHG) standards (Figure 10). This projection is a significant departure from the historical trend. Transportation energy consumption grew by an average of 1.3%/year from 1973 to 2007—when it peaked at 28.7 quadrillion Btu—as a result of increases in demand for personal travel and movement of goods that outstripped gains in fuel efficiency.

Transportation sector energy consumption varies across the alternative cases (Figure 11). Compared with the Reference case, energy consumption levels in 2040 are higher in the High Economic Growth case (by 3.0 quadrillion Btu), Low Oil Price case (by 1.4 quadrillion Btu), and High Oil and Gas Resource case (by 1.2 quadrillion Btu) and lower in the High Oil Price case (by 1.4 quadrillion Btu) and Low Economic Growth case (by 2.6 quadrillion Btu).

In the Reference case, energy consumption by LDVs—including passenger cars, light-duty trucks, and commercial light-duty trucks—falls from 15.7 quadrillion Btu in 2013 to 12.6 quadrillion Btu in 2040, as increases in fuel economy more than offset increases in LDV travel. Total vehicle miles traveled (VMT) for LDVs increase by 36% from 2013 (2,711 billion miles) to 2040 (3,675 billion miles), and the average VMT per licensed driver increase from about 12,200 miles in 2013 to 13,300 miles in 2040. The fuel economy of new vehicles increases from 32.8 mpg in 2013 to 48.1 mpg in 2040, as more stringent CAFE and GHG emissions standards take effect. As a result, the average fuel economy of the LDV stock increases by 69%, from 21.9 mpg in 2013 to 37.0 mpg in 2040.

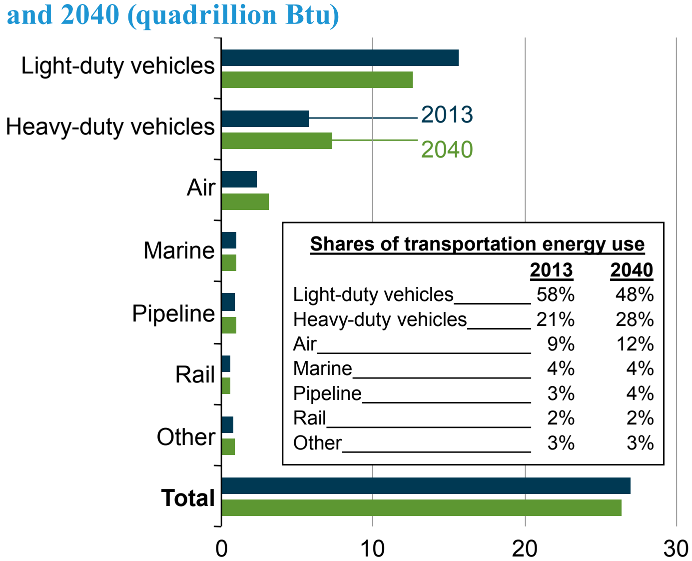
Passenger vehicles fueled exclusively by motor gasoline for all motive and accessory power, excluding any hybridization and flex-fuel capabilities, accounted for 83% of new sales in 2013. In the AEO2015 Reference case, gasoline-only vehicles, excluding hybridization or flex-fuel capabilities, still represent the largest share of new sales in 2040, at 46% of the total (see the first box below for comparison of relative economics of various technologies). However, alternative fuel vehicles and vehicles with hybrid technologies gain significant market shares, including gasoline vehicles equipped with micro hybrid systems (33%), E85 flex-fuel vehicles (10%), full hybrid electric vehicles (5%), diesel vehicles (4%), and plug-in hybrid vehicles and electric vehicles (2%). (EIA considers several types of hybrid electric vehicles—micro, mild, full, and plug-in—as described in the box on page 11.)

In comparison with the Reference case, LDV energy consumption in 2040 is higher in the Low Oil Price case (14.3 quadrillion Btu), High Economic Growth case (13.2 quadrillion Btu), and High Oil and Gas Resource case (12.9 quadrillion Btu), as a result of projected higher VMT in all three cases and lower fuel economy in the Low Oil Price and High Oil and Gas Resource cases. Conversely, LDV energy consumption in 2040 in the High Oil Price case (10.6 quadrillion Btu) and the Low Economic Growth case (11.3 quadrillion Btu) is lower than projected in the Reference case, as a result of lower VMT in both cases and higher fuel economy in the High Oil Price case.

Energy use by all heavy-duty vehicles (HDVs)—including tractor trailers, buses, vocational vehicles,[19] and heavy-duty pickups and vans—increases from 5.8 quadrillion Btu (2.8 million bbl/d) in 2013 to 7.3 quadrillion Btu (3.5 million bbl/d) in 2040, with higher VMT only partially offset by improved fuel economy. HDV travel grows by 48% in the Reference case—as a result of increases in industrial output—from 268 billion miles in 2013 to 397 billion miles in 2040, while average HDV fuel economy increases from 6.7 mpg in 2013 to 7.8 mpg in 2040 as a result of HDV fuel efficiency standards and GHG emissions standards. Diesel remains the most widely used HDV fuel. The share of diesel falls from 92% of total HDV energy use in 2013—with the remainder 7% motor gasoline and 1% gaseous (propane, natural gas, liquefied natural gas)—to 87% diesel in 2040, with natural gas, either compressed or liquefied, accounting for 7% of HDV energy use in 2040 as the economics of natural gas fuels improve and the refueling infrastructure expands.

The largest differences from the Reference case level of HDV energy consumption in 2040 are in the High and Low Economic Growth cases (9.4 quadrillion Btu and 6.3 quadrillion Btu, respectively), as a result of their higher and lower projections for travel demand, respectively. Notably, the use of natural gas is significantly higher in the High Oil Price case than in the Reference case, at nearly 30% of total HDV energy use in 2040.

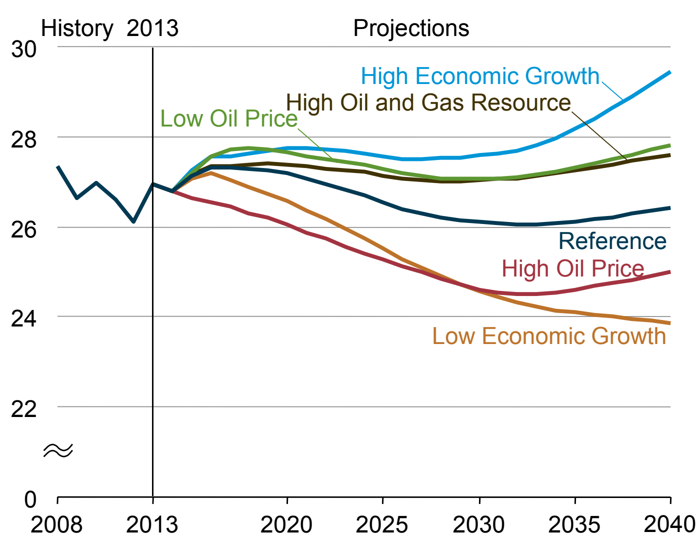
Figure 10. Delivered energy consumption for transportation by mode in the Reference case, 2013 and 2040 (quadrillion Btu)



	2013	2040
Light-duty vehicles	58%	48%
Heavy-duty vehicles	21%	28%
Air	9%	12%
Marine	4%	4%
Pipeline	3%	4%
Rail	2%	2%
Other	3%	3%

Note: The sum of the shares may not equal 100% due to independent rounding.

Figure 11. Delivered energy consumption for transportation in six cases, 2008-40 (quadrillion Btu)

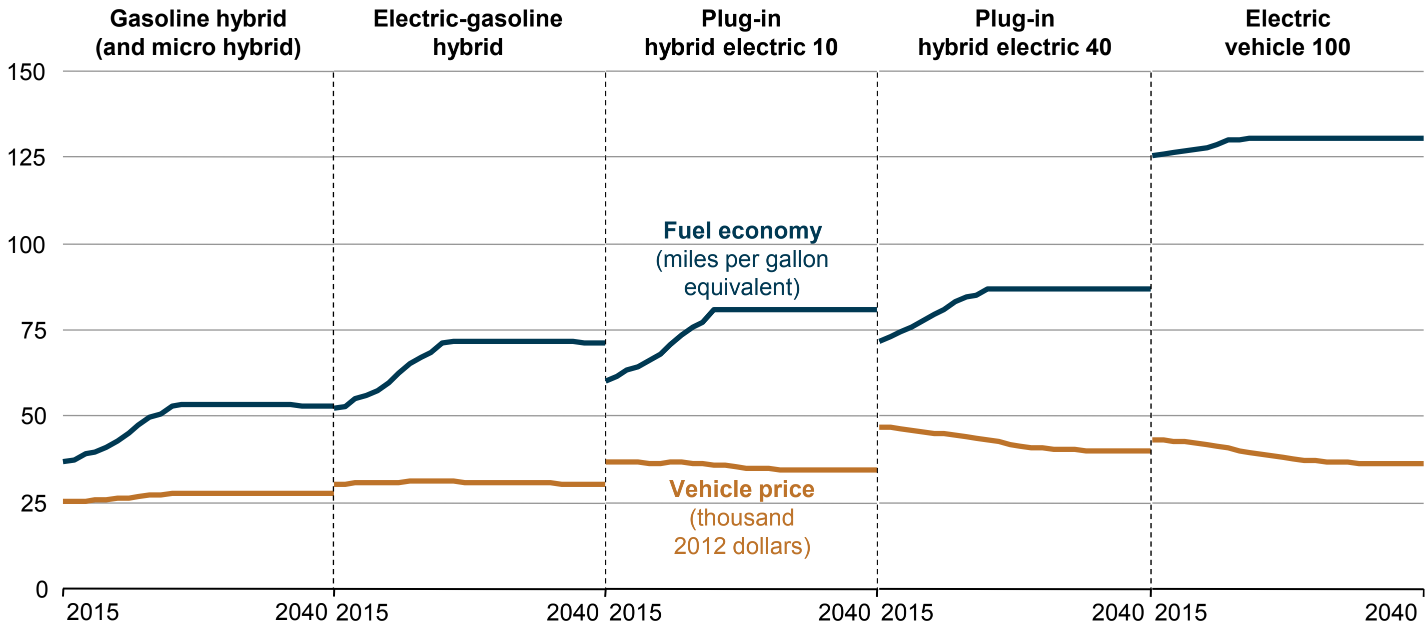


[19]Vocational vehicles include a diverse group of heavy-duty trucks, such as box/delivery trucks, refuse haulers, dump trucks, etc.

Future gasoline vehicles are strong competitors when compared with other vehicle technology types on the basis of fuel economics

Several fuel-efficient technologies are currently, or are expected to be, available for all vehicle fuel types. Those technologies will enable manufacturers to meet upcoming CAFE and GHG emissions standards at a relatively modest cost, predominately with vehicles powered by gasoline only or with gasoline-powered vehicles employing micro hybrid systems. Because of diminishing returns from improved fuel economy, future gasoline vehicles, including those with micro hybrid systems, are strong competitors when compared with other, more expensive vehicle technology types on the basis of fuel economics. Even though the price of vehicles that use some electric drive for motive power is projected to decline, in some cases significantly, their relative cost-effectiveness does not improve over the projection period, due to advances in gasoline-only and gasoline micro hybrid vehicles. While the reasons for consumer vehicle purchases vary and are not always on a strictly economic basis, wider market acceptance would require more favorable fuel economics—as seen in the High Oil Price case, where sales of plug-in hybrid and electric vehicle sales more than double.

Midsize passenger car fuel economy and vehicle price by technology type in the Reference case, 2015-2040



In 2040, compared with gasoline vehicles, fuel cost savings would be $227/year for an electric-gasoline hybrid, with a "payback period" of approximately 13 years for recovery of the difference in vehicle purchase price compared with a conventional gasoline vehicle; $247/year for a PHEV10, with a 27-year payback period; $271/year for a PHEV40, with a 46-year payback period; and $469/year for a 100% electric drive vehicle, with a 19-year payback period. These results are based on the following assumptions for each vehicle type: 12,000 miles traveled per year; average motor gasoline price of $3.90 per gallon; average electricity price of $0.12 per kilowatthour; and 0% discount rate. For plug-in hybrids it is assumed that a hybrid electric 10 (PHEV10) will use electric drive power for 21% of total miles traveled, and a hybrid electric 40 (PHEV40) for 58% of total miles traveled. The assumed vehicle purchase prices do not reflect national or local tax incentives.

The *Annual Energy Outlook 2015* includes several types of light-duty vehicle hybrid technology

Micro hybrids, also known as start/stop technology, are those vehicles with an electrically powered auxiliary system that allow the internal combustion engine to be turned off when the vehicle is coasting or idle and then quickly restarted. These systems do not provide power to the wheels for traction and can use regenerative braking to recharge the batteries.

Mild hybrids are those vehicles that, in addition to start/stop capability, provide some power assist to the wheels but no electric-only motive power.

Full hybrid electric vehicles can, in addition to start/stop and mild capabilities, operate at slow speeds for limited distances on the electric motor and assists the drivetrain throughout its drive cycle. Full hybrid electric vehicle systems are configured in parallel, series, or power split systems, depending on how power is delivered to the drivetrain.

Plug-in hybrid electric vehicles have larger batteries to provide power to drive the vehicle for some distance in charge-depleting mode, until a minimum level of battery power is reached (a "minimum state of charge"), at which point they operate on a mixture of battery and internal combustion engine power ("charge-sustaining mode"). PHEVs also can be engineered to run in a "blended mode," using an onboard computer to determine the most efficient use of battery and engine power. The battery can be recharged either from the grid (plugging a power cord into an electrical outlet) or by the engine.

Aircraft energy consumption increases from 2.3 quadrillion Btu in 2013 to 3.1 quadrillion Btu in 2040, with growth in personal air travel partially offset by gains in aircraft fuel efficiency. Energy consumption by marine vessels (including international marine, recreational boating, and domestic marine) remains flat, as increases in demand for international marine and recreational boating are offset by declines in fuel use for domestic marine vessels. The decline in domestic marine energy use is the result of improved efficiency and the continuation of the historical decline in travel demand. In the near term, distillate fuel provides a larger share of the fuel used by marine vessels, the result of stricter fuel and emissions standards. Pipeline energy use increases slowly, with growing volumes of natural gas produced from tight formations that are relatively close to end-use markets. Energy consumption for rail travel (freight and passenger) also remains flat, as improvement in locomotive fuel efficiency offsets growth in travel demand. In 2040, natural gas provides about a third of the fuel used for freight rail.

Industrial

Delivered energy consumption in the industrial sector totaled 24.5 quadrillion Btu in 2013, representing approximately 34% of total U.S. delivered energy consumption. In the AEO2015 Reference case, industrial delivered energy consumption grows at an annual rate of 0.7% from 2013 to 2040. The annual growth rate is much higher from 2013 to 2025 (1.3%) than from 2025 to 2040 (0.2%), as increased international competition slows industrial production growth and energy efficiency continues to improve in the industrial sector over the long term. Among the alternative cases, delivered industrial energy consumption grows most rapidly in the High Economic Growth case at 1.2%/year, almost twice the rate in the Reference case. The slowest growth in industrial energy consumption is projected in the Low Economic Growth case, at 0.4%/year from 2013 to 2040 (Figure 12).

Total industrial natural gas consumption in the AEO2015 Reference case increases from 9.1 quadrillion Btu in 2013 to 11.2 quadrillion Btu in 2040. Natural gas is used in the industrial sector for heat and power, bulk chemical feedstocks, natural gas-to-liquids (GTL) heat and power, and lease and plant fuel. The 6.7 quadrillion Btu of natural gas used for heat and power in 2013 was 74% of total industrial natural gas consumption for the year. From 2013 to 2040, natural gas use for heat and power grows by an average of 0.4%/year in the Reference case, with 41% of the total growth occurring between 2013 and 2020. In the High Oil and Gas Resource case, natural gas use for heat and power grows by 0.7%/year from 2013 to 2040, largely as a result of oil and gas extraction activity (Figure 13).

Natural gas use for GTL is responsible for the rapid post-2025 consumption growth in the High Oil Price compared with the other two cases shown in Figure 13. In the High Oil Price case, natural gas use for heat and power increases by 1.0%/year from 2013 to 2040, including significant use for GTL production, which grows to about 1 quadrillion Btu in 2040 in the High Oil Price case. Natural gas use for GTL occurs only in the High Oil Price case. Market conditions (primarily liquid fuel prices) do not support GTL investments in the other cases.

Purchased electricity (excluding electricity generated and used onsite) used by industrial customers in the AEO2015 Reference case grows from 3.3 quadrillion Btu in 2013 to 4.1 quadrillion Btu in 2040. Most of the growth occurs between 2013 and 2025, when it averages 1.7%/year. After 2025, there is little growth in purchased electricity consumption in the Reference case. In the High Economic Growth case, purchased electricity consumption grows by 1.5%/year from 2013 to 2040, which is almost twice the rate in the Reference case. Consumption increases significantly from 2025 to 2040 in the High Economic Growth case, as shipments of industrial products increase relatively more than in the Reference case and do not slow down nearly as much after 2025.

Figure 12. Industrial sector total delivered energy consumption in three cases, 2010-40 (quadrillion Btu)

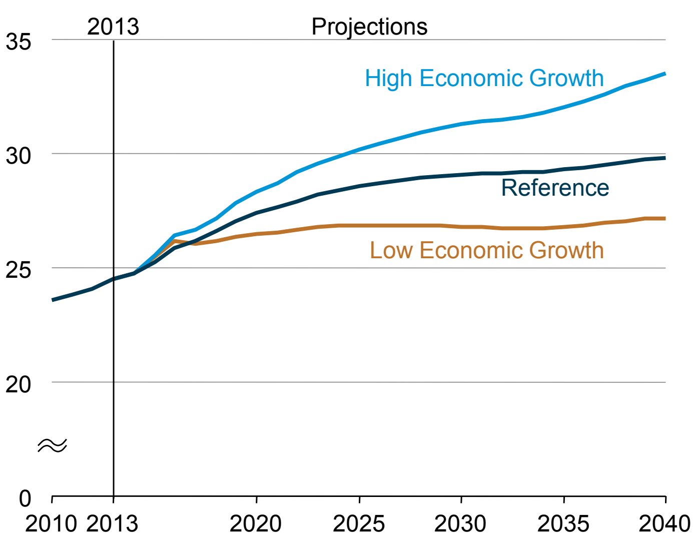
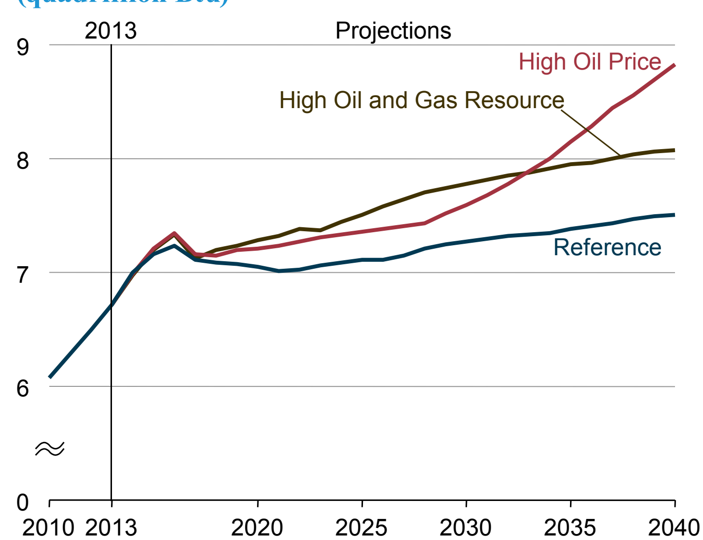


Figure 13. Industrial sector natural gas consumption for heat and power in three cases, 2010-40 (quadrillion Btu)



Purchased electricity consumption in the five metal-based durables industries,[20] which accounted for nearly 25% of the industrial sector total in 2013, grows at a slightly higher rate than in other industries in the Reference case. Although metal-based durable industries are not energy-intensive, they are relatively electricity-intensive, and they are by far the largest industry subgroup as measured by shipments in 2013. In the High Economic Growth case, shipments of metal-based durables grow more rapidly than shipments from many of the other industry segments. As a result, purchased electricity consumption in the metal-based durables industries grows by 2.0% per year from 2013 to 2040 in the High Economic Growth case, which is higher than the rate of growth for the industry in the Reference case.

Combined heat and power (CHP) generation in the industrial sector—almost all of which occurs in the bulk chemicals, food, iron and steel, paper, and refining industries—grows by 50% from 147 billion kWh in 2013 to 221 billion kWh in 2040 in the AEO2015 Reference case. Most of the CHP generation uses natural gas, although the paper industry also has a significant amount of renewables-based generation. All of the CHP-intensive industries are also energy intensive. Growth in CHP generation is slightly higher than growth in purchased electricity consumption, despite a shift toward lower energy intensity in the manufacturing and service sectors in the United States.

Bulk chemicals are the most energy-intensive segment of the industrial sector. In the AEO2015 Reference case, energy consumption in the U.S. bulk chemicals industry, which totaled 5.6 quadrillion Btu in 2013, grows by an average of 2.3%/year from 2013 to 2025. After 2025, energy consumption growth in bulk chemicals is negligible, as U.S. shipments of bulk chemicals begin to decrease because of increased international competition.

Approximately 60% of energy use in the bulk chemicals industry over the projection period is for feedstocks. Hydrocarbon gas liquids (HGL)[21] and petroleum products (such as naphtha)[22] are used as feedstocks for organic chemicals, inorganic chemicals, and resins. Growth in natural gas production from shale formations has contributed to an increase in the supply of HGL. Some chemicals can use either HGL or petroleum as feedstock; for those chemicals, the feedstock used depends on the relative prices of natural gas and petroleum. Although HGL or petroleum is used as a feedstock for most chemicals, natural gas feedstocks are used to manufacture methanol and agricultural chemicals. Natural gas feedstock consumption, which constituted roughly 13% of total bulk chemical feedstock consumption in 2013, grows rapidly from 2014 to 2018, reflecting increased capacity in the U.S. agricultural chemicals industry.

Residential and commercial

Delivered energy consumption decreases at an average rate of 0.3%/year in the residential sector and grows by 0.6%/year in the commercial sector from 2013 through 2040 in the AEO2015 Reference case (Figure 14 and Figure 15). Over the same period, the total number of households grows by 0.8%/year, and commercial floorspace increases by 1.0%/year (Table 4). The AEO2015 alternative cases illustrate the effects of different assumptions on residential and commercial energy consumption. Higher or lower economic growth, fuel prices, and fuel resources yield a range of residential and commercial energy demand. Different

Figure 14. Residential sector delivered energy consumption by fuel in the Reference case, 2010-40 (quadrillion Btu)

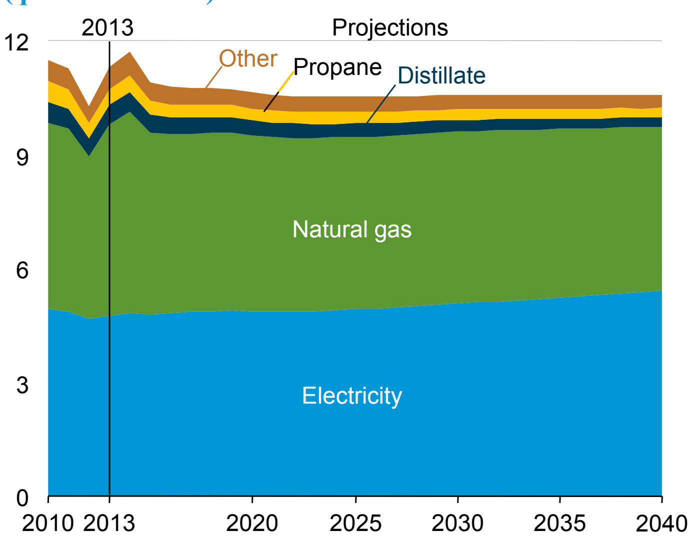
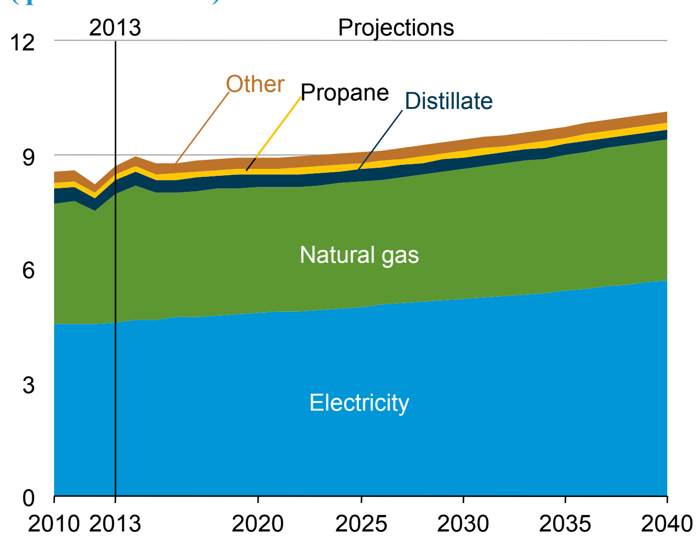


Figure 15. Commercial sector delivered energy consumption by fuel in the Reference case, 2010-40 (quadrillion Btu)



[20]The five metal-based durables industries are fabricated metal products (NAICS 332), machinery (NAICS 333), computers (NAICS 335), transportation equipment (NAICS 336), and electrical equipment (NAICS 335).

[21]Hydrocarbon gas liquids are natural gas liquids (NGL) and olefins. NGL include ethane, propane, normal butane, isobutane, and natural gasoline. Olefins include ethylene, propylene, butylene, and isobutylene. See http://www.eia.gov/tools/glossary/index.cfm?id=Hydrocarbon%20gas%20liquids.

[22]Naphtha is a refined or semi-refined petroleum fraction used in chemical feedstocks and many other petroleum products, see www.eia.gov/tools/glossary/index.cfm?id=naphtha.

levels of economic growth affect the number of households more than the amount of commercial floorspace, leading to greater differences in residential energy demand across the cases.

In the Reference case, electricity consumption in the residential and commercial sectors increases by 0.5%/year and 0.8%/year from 2013 through 2040, respectively, with the growth in residential electricity use ranging from 0.2%/year to 0.9%/year and the growth in commercial electricity use ranging from 0.7% to 0.9%/year in the alternative cases. In all cases, demand shifts from space heating to space cooling as a growing share of the population moves to warmer regions of the country. Miscellaneous electric loads (MELs)—from a variety of devices and appliances that range from microwave ovens to medical imaging equipment—continue to grow in the residential and commercial sectors, showing both increased market penetration (the share of the potential market that uses the device) and saturation (the number of devices per building).

In the commercial sector, the use of computer servers continues to grow to meet increasing needs for data storage, data processing, and other cloud-based services; however, only a small number of servers are installed in large, dedicated data center buildings. Most of the electricity used by servers can be attributed to equipment located in server rooms at the building site in offices, education buildings, and healthcare facilities.

Residential natural gas use declines in the Reference case with improvements in equipment and building shell efficiencies, price increases over time, and reduced heating needs as populations shift. Natural gas consumption in the commercial sector would be relatively flat as a result of efficiency improvements that offset floorspace growth, but increases in natural gas-fueled CHP capacity keep sector consumption trending upward throughout the projection. In the residential and commercial sectors, natural gas prices increase 2.5 and 3.0 times faster, respectively, than electricity prices through 2040 in the Reference case. In the High Oil and Gas Resources case, with lower natural gas prices, commercial delivered natural gas consumption grows by 0.7%/year, or more than twice the rate in the Reference case.

In the residential sector, distillate consumption and propane consumption, primarily for space heating, decline by 2.7%/year and 2.0%/year, respectively, in the Reference case from 2013 to 2040. The declines are even larger in the High Oil Price case, at 3.1%/year and 2.3%/year for distillate and propane, respectively, over the same period.

End-use energy intensity, as measured by consumption per residential household or square foot of commercial floorspace, decreases in the Reference case as a result of increases in the efficiency of equipment for many end uses (Figure 16 and Figure 17). Federal standards and voluntary market transformation programs (e.g., Energy Star) target uses such as space heating and cooling, water heating, lighting, and refrigeration, as well as devices that are rapidly proliferating, such as set-top boxes and external power supplies.

As a result of collaboration among industry, efficiency advocates, and government, a voluntary agreement for set-top boxes has been issued in lieu of federal standards.[23] Commercial refrigeration standards that will affect walk-in and reach-in coolers and freezers are under discussion among stakeholders.[24] As more states adopt new building codes, shell efficiencies of newly constructed buildings are improving, which will reduce future energy use for heating and cooling in the residential and commercial sectors.

In the AEO2015 Reference case, residential and commercial energy intensities for miscellaneous electric loads (MEL) and nonelectric miscellaneous uses in 2040 are roughly 18% and 23% higher, respectively, than they were in 2013. These devices and appliances vary greatly in their energy use characteristics, and their total energy consumption is closely tied to their levels of

Table 4. Residential households and commercial indicators in three AEO2015 cases, 2013 and 2040

Indicator	2013	2040	Average annual growth rate, 2013-40 (percent per year)
Residential households (millions)			
High Economic Growth	114.3	158.5	1.2
Reference	114.3	141.0	0.8
Low Economic Growth	114.3	127.9	0.4
Commercial floorspace (billion square feet)			
High Economic Growth	82.8	112.4	1.1
Reference	82.8	109.1	1.0
Low Economic Growth	82.8	106.0	0.9

[23] Following a consensus agreement among manufacturers and industry representatives that is expected to achieve significant energy savings, the U.S. Department of Energy (DOE) has withdrawn its proposed rulemaking for set-top boxes. See https://www.federalregister.gov/articles/text/raw_text/201/331/264.txt.

[24] Walk-in coolers and walk-in freezer panels, doors, and refrigeration systems are currently scheduled to comply with the updated standard beginning in August 2017 (see http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/26), and DOE has denied a petition from the Air-Conditioning, Heating, and Refrigeration Institute (AHRI) to reconsider its final rulemaking (see http://www.energy.gov/sites/prod/files/2014/09/f18/petition_denial.pdf).

penetration and saturation in the buildings sectors. As a result, MEL and nonelectric miscellaneous uses are difficult targets for federal efficiency standards.[25]

Penetration of grid-connected distributed generation continues to grow as both equipment and non-equipment costs decline, slowing delivered electricity demand growth in both residential and commercial buildings. In the AEO2015 Reference case, solar photovoltaic (PV) capacity in the residential sector grows by an average of about 30%/year from 2013 through 2016, compared with 9%/year for commercial sector PV, driven by the recent popularity of third-party leasing and other innovative financing options and tax credits. Following expiration of the 30% federal investment tax credit at the end of 2016, the average annual growth of PV capacity in residential and commercial buildings slows to about 6% in both sectors through 2040.

Natural gas CHP capacity in the commercial sector grows by an average of 9%/year from 2013 to 2040 in the Reference case and shows little variation across the alternative cases. Although natural gas prices are lower in the High Oil and Gas Resource case than in the Reference case, lower electricity prices limit the attractiveness of commercial CHP relative to purchased electricity.

Figure 16. Residential sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040 (million Btu per household per year)

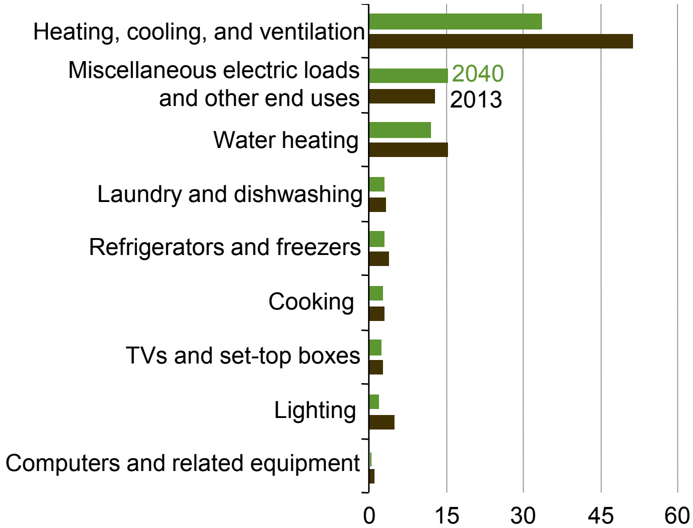
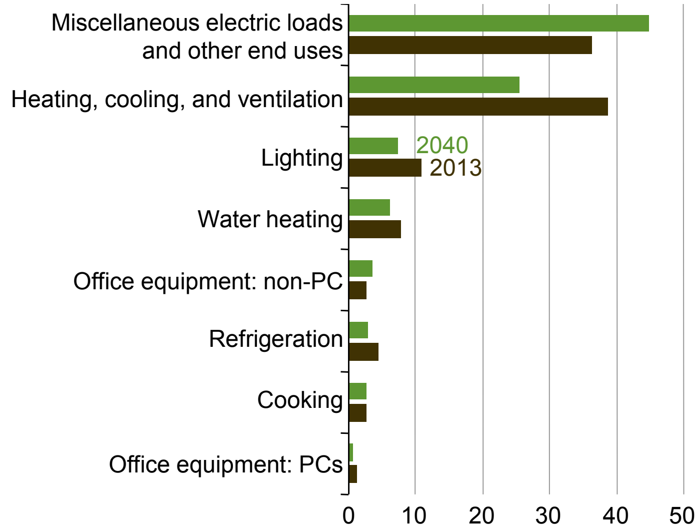


Figure 17. Commercial sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040 (thousand Btu per square foot per year)

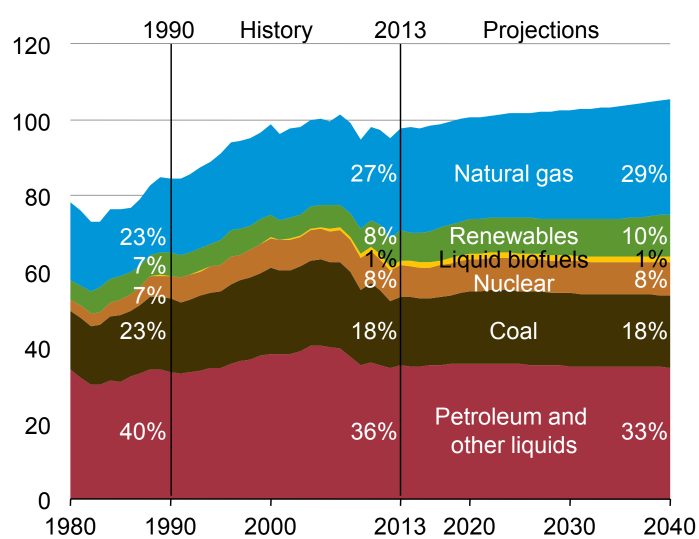


Energy consumption by primary fuel

Total primary energy consumption grows in the AEO2015 Reference case by 8.6 quadrillion Btu (8.9%), from 97.1 quadrillion Btu in 2013 to 105.7 quadrillion Btu in 2040 (Figure 18). Most of the growth is in consumption of natural gas and renewable energy. Consumption of petroleum products across all sectors in 2040 is unchanged from 2013 levels, as motor gasoline consumption in the transportation sector declines as a result of a 70% increase in the average efficiency of on-road light-duty vehicles (LDVs), to 37 mpg in 2040, which more than offsets projected growth in vehicle miles traveled (VMT). Total motor gasoline consumption in the transportation sector is about 3.4 quadrillion Btu (1.8 million barrels per day (bbl/d)) lower in 2040 than in 2013, and total petroleum consumption in the transportation sector is about 1.6 quadrillion Btu (0.9 million bbl/d) lower in 2040 than in 2013.

U.S. consumption of petroleum and other liquids, which totaled 35.9 quadrillion Btu (19.0 million bbl/d) in 2013, increases to 37.1 quadrillion Btu (19.6 million bbl/d) in 2020, then declines to 36.2 quadrillion Btu (19.3 million bbl/d) in

Figure 18. Primary energy consumption by fuel in the Reference case, 1980-2040 (quadrillion Btu)



[25]Navigant Consulting Inc. and Leidos—formerly SAIC, *Analysis and Representation of Miscellaneous Electric Loads in NEMS*, prepared for the U.S. Energy Information Administration (Washington, DC: May 2013), http://www.eia.gov/analysis/studies/demand/miscelectric/.

2040. In the transportation sector, which continues to dominate demand for petroleum and other liquids, there is a shift from motor gasoline to distillate. The gasoline share of total demand for transportation petroleum and other liquids declines by 10.6 percentage points, while distillate consumption increases by 7.2 percentage points. Increased use of compressed natural gas and LNG in vehicles also replaces about 3% of petroleum and other liquids consumption in the transportation sector in 2040. Consumption of ethane and propane (the latter including propylene), which are used in chemical production, shows the largest increase of all petroleum products in the AEO2015 Reference case from 2013 to 2040. Industrial consumption of ethane and propane, extracted from wet gas in natural gas processing plants, grows by almost 1 quadrillion Btu (790 thousand bbl/d) as dry natural gas production increases.

Natural gas consumption in the AEO2015 Reference case increases from 26.9 quadrillion Btu (26.2 Tcf) in 2013 to 30.5 quadrillion Btu (29.7 Tcf) in 2040. The largest share of the growth is for electricity generation in the electric power sector, where demand for natural gas grows from 8.4 quadrillion Btu (8.2 Tcf) in 2013 to 9.6 quadrillion Btu (9.4 Tcf) in 2040, in part as a result of the retirement of 40.1 GW of coal-fired capacity by 2025. Natural gas consumption in the industrial sector also increases, rapidly through 2016 and then more slowly through 2040, benefiting from the increase in shale gas production that is accompanied by slower growth of natural gas prices. Industries such as bulk chemicals, which use natural gas as a feedstock, are more strongly affected than others. Natural gas use as a feedstock in the chemical industry increases by about 0.4 quadrillion Btu from 2013 to 2040. In the residential sector, natural gas consumption declines from 2018 to 2040 and it increases slightly in the commercial sector over the same period.

Coal use in the Reference case grows from 18.0 quadrillion Btu (925 million short tons) in 2013 to 19.0 quadrillion Btu (988 million short tons) in 2040. As previously noted, the Reference case and other AEO2015 cases do not include EPA's proposed Clean Power Plan, which if it is implemented is likely to have a significant effect on coal use. Coal use in the industrial sector falls off slightly over the projection period, as steel production becomes more energy efficient. On the other hand, if oil prices were significantly higher than projected in the Reference case, coal could be used to make liquids via the Fischer-Tropsch process. In the High Oil Price case—the only AEO2015 case in which coal-to-liquids (CTL) technology becomes economically viable—liquids production from CTL plants totals about 710,000 bbl/d in 2040, representing about 3.3 quadrillion Btu (including liquids value), or about 180 million short tons, of coal consumption.

Consumption of marketed renewable energy increases by about 3.6 quadrillion Btu in the Reference case, from 9.0 quadrillion Btu in 2013 to 12.5 quadrillion Btu in 2040, with most of the growth in the electric power sector. Hydropower, the largest category of renewable electricity generation in 2013, contributes little to the increase in renewable fuel consumption. Wind-powered generation, the second-largest category of renewable electricity generation in 2013, becomes the largest contributor in 2038 (including wind generation by utilities and end-users onsite). However, solar photovoltaics (6.8%/year), geothermal (5.5%/year), and biomass (3.1%/year) all increase at faster average annual rates than wind (2.4%/year), including all sectors. Modest penetration of E85 and a small increase in liquids blended into diesel fuel result in a slight increase in consumption of renewable liquid fuels for transportation, despite a smaller pool for ethanol blending as a result of a projected overall decrease in motor gasoline consumption in the AEO2015 Reference case.

In the High Oil Price case, total primary energy use in 2040 is 109.7 quadrillion Btu, 3.9 quadrillion Btu higher than in the Reference case, even though total liquids consumption in 2040 is 3.3 quadrillion Btu lower, despite an 0.3 quadrillion Btu increase in renewable liquids. The decrease in petroleum and other liquids consumption is more than offset by increased consumption of natural gas (31.8 quadrillion Btu in 2040, 1.3 quadrillion Btu more than in the Reference case), coal (21.6 quadrillion Btu in 2040, 2.6 quadrillion Btu more, not including the Fischer-Tropsch coal consumed as liquids), nuclear (9.8 quadrillion Btu in 2040, 1.1 quadrillion Btu more), and many renewables (13.2 quadrillion Btu in 2040, 2.3 quadrillion Btu more, not including consumption of liquids from renewable fuels). The increases in coal and natural gas consumption are explained by the attractiveness of turning them into liquid fuels, made profitable by higher oil prices despite lower demand for motor gasoline and diesel fuels.

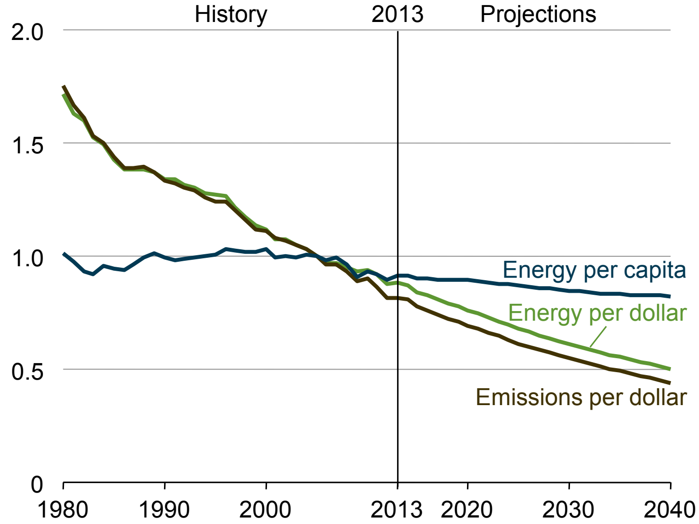
Uncertainty about economic growth results in the widest variation in the projections for total primary energy consumption in 2040, ranging from 98.0 quadrillion Btu in the Low Economic Growth case (1.8% average annual growth in real GDP measured in 2009 dollars) to 116.2 quadrillion Btu in the High Economic Growth case (2.9% average annual growth in real GDP). Changes in the assumed rate of economic growth lead to variations in the growth of energy consumption across all fuels, whereas changes in crude oil prices or in the size of the oil and natural gas resource base result in shifts among the fuel types consumed, with some fuels gaining share and others losing share. In the Low Oil Price case, the petroleum and other liquids share of total energy consumption is about 36.4% in 2040; in the High Oil Price case, it is 30.0% in the same year. With cheaper natural gas in the High Oil and Gas Resource case, less electricity is generated from coal and renewable fuels.

Energy intensity

Energy intensity (measured both by energy use per capita and by energy use per dollar of GDP) declines in the AEO2015 Reference case over the projection period (Figure 19). While a portion of the decline results from a small shift from energy-intensive to nonenergy-intensive manufacturing, most of it results from changes in other sectors.

Increasing energy efficiency reduces the energy intensity of many residential end uses between 2013 and 2040. Total energy consumption for space heating is 4.2 quadrillion Btu in 2040, 1.7 quadrillion Btu (57%) lower than it was in 2013, despite a 23% increase in the number of households and an 11% increase in the average size (square feet) of a household. Energy use for lighting is 0.8 quadrillion Btu in 2040, 1.0 quadrillion Btu lower than it was in 2013 reflecting a 57% decline in energy use despite an increase in lighting services. Energy use for computers and related equipment is 0.1 quadrillion Btu, 0.2 quadrillion Btu lower than it was in 2013. Improved efficiency also reduces delivered energy use in the transportation sector from 27.0 quadrillion Btu in 2013 to 26.5 quadrillion Btu in 2040, by 0.5 quadrillion Btu, as motor gasoline consumption declines by 3.4 quadrillion Btu. The result is an average annual reduction in energy use per capita of 0.4%/year from 2013 through 2040 and an average annual decline in energy use per 2009 dollar of GDP of 2.0%/year. As renewable fuels and natural gas account for larger shares of total energy consumption, carbon intensity (CO2 emissions per unit of GDP) declines by 2.3%/year from 2013 to 2040.

Figure 19. Energy use per capita and per 2009 dollar of gross domestic product, and carbon dioxide emissions per 2009 dollar of gross domestic product, in the Reference case, 1980-2040 (index, 2005 = 1.0)



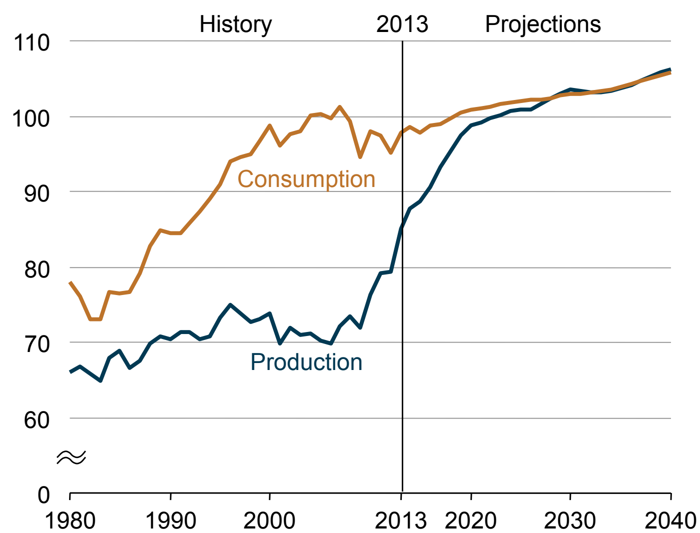
Macroeconomic growth has the largest impact on energy intensity among the AEO2015 alternative cases. Real GDP grows by an average of 1.8%/year from 2013 to 2040 in the Low Economic Growth case, and population grows by an average of 0.6%/year over the same period. Even though energy use increases only slightly (growing by 0.9 quadrillion Btu from 2013 to 2040) because GDP growth is lower than in the other cases, energy intensity as measured in relationship to GDP declines the least—an average rate of 1.8% per year from 2013 to 2040. However, the same case shows the largest decline in energy use per person, averaging 0.5%/year from 2013 to 2040. In the High Economic Growth case, real GDP increases at an average annual rate of 2.9%/year, population grows at an average annual rate of 0.8%/year, and energy use increases at an average annual rate of 0.7%/year from 2013 to 2040. As a result, the energy intensity of GDP declines at a slightly higher rate than in the Reference case, while the decline in energy use per person is slower than in the Reference case.

Energy production, imports, and exports

Net U.S. imports of energy declined from 30% of total energy consumption in 2005 to 13% in 2013, as a result of strong growth in domestic oil and dry natural gas production from tight formations and slow growth of total energy consumption. The decline in net energy imports is projected to continue at a slower rate in the AEO2015 Reference case, with energy imports and exports coming into balance around 2028 (although liquid fuel imports continue, at a reduced level, throughout the Reference case). From 2035 to 2040, energy exports account for about 23% of total annual U.S. energy production in the Reference case (Figure 20). Economic growth has a major influence on U.S. energy consumption, imports, and exports. In the High Economic Growth case, the United States remains a net energy importer through 2040, with net imports equal to about 3% of consumption in 2040. In the Low Economic Growth case, the United States becomes a net exporter of energy in 2022, with energy exports equal to 4% of total domestic energy production in 2040.

Changes in the world oil price affect both consumption and production, but in opposite directions from the effects of changes in U.S. economic growth. Higher world oil prices place downward pressure on consumption while making domestic production more profitable. In the Low Oil Price case, with lower domestic production and higher U.S. energy consumption, the United States remains a net energy importer, with imports increasing every year from 2033 to 2040 and net imports equal to 9% of total domestic energy

Figure 20. Total energy production and consumption in the Reference case, 1980-2040 (quadrillion Btu)



consumption in 2040. In the High Oil Price case, with stronger growth in production and more incentives for energy efficiency, the United States becomes and remains a net energy exporter starting in 2019, and net exports increase to 9% of total energy production in 2040 after peaking at 11% in 2032. In the High Oil and Gas Resource case, with faster growth in domestic natural gas and crude oil production, U.S. net energy exports, mostly in the form of petroleum and natural gas, grow to almost 19% of total domestic energy production in 2040.

Petroleum and other liquids

Production from tight formations leads the growth in U.S. crude oil production across all AEO2015 cases. The path of projected crude oil production varies significantly across the cases, with total U.S. crude oil production reaching high points of 10.6 million barrels per day (bbl/d) in the Reference case (in 2020), 13.0 million bbl/d in the High Oil Price case (in 2026), 16.6 million bbl/d in the High Oil and Gas Resource case (in 2039), and 10.0 million bbl/d in the Low Oil Price case (in 2020).

In the Reference case, the existing U.S. competitive advantage in oil refining compared to the rest of the world continues over the projection period. This advantage results in growing gasoline and diesel exports through 2040 in the Reference case. The production of motor gasoline blending components, which totaled 7.9 million bbl/d in 2013, begins declining in 2015 and falls to 7.2 million bbl/d by the end of the projection period, while diesel fuel production rises from 4.2 million bbl/d in 2013 to 5.3 million bbl/d in 2040. As a result of declining consumption of liquid fuels and increasing production of domestic crude oil, net imports of crude oil and petroleum products fall from 6.2 million bbl/d in 2013 (33% of total domestic consumption) to 3.3 million bbl/d in 2040 (17% of domestic consumption) in the Reference case. Growth in gross exports of refined petroleum products, particularly of motor gasoline and diesel fuel, results in a significant increase in net petroleum product exports between 2013 and 2040.

In both the High Oil and Gas Resource and High Oil Price cases, total U.S. crude oil production is higher than in the Reference case mainly as a result of growth in tight oil production, which rises at a substantially faster rate in the near term in both cases than in the Reference case. In the High Oil and Gas Resource case, tight oil production grows in response to assumed higher estimated ultimate recovery (EUR) and technology improvements, closer well spacing, and development of new tight oil formations or additional layers within known tight oil formations. Total crude oil production reaches 16.6 million bbl/d in 2037 in the High Oil and Gas Resource case. In the High Oil Price case, higher oil prices improve the economics of production from new wells in tight formations as well as from other domestic production sources, leading to a more rapid increase in production volumes than in the Reference case. Tight oil production increases through 2022, when it totals 7.4 million bbl/d. After 2022, tight oil production declines, as drilling moves into less productive areas. Total U.S. crude oil production reaches 13.0 million bbl/d by 2025 in the High Oil Price case before declining to 9.9 million bbl/d in 2040 (Figure 21 and Figure 22).

Recent declines in West Texas Intermediate[26] oil prices (falling by 59% from June 2014 to January 2015) have triggered interest in the effect of lower prices on U.S. oil production. In the Low Oil Price case, domestic crude oil production is 9.8 million bbl/d in 2022, 0.7 million bbl/d lower than the 10.4 million bbl/d in the Reference case. In 2040, U.S. crude oil production is 7.1 million bbl/d, 2.3 million bbl/d lower than the 9.4 million bbl/d in the Reference case. Most of the difference in total crude oil production levels between the Reference and Low Oil Price cases reflects changes in production from tight oil formations. However, all sources of U.S. oil production are adversely affected by low oil prices. As crude oil prices fall and remain at or below $76/barrel (Brent) in the Low Oil Price case after 2014, poor investment returns lead to fewer wells being drilled in noncore areas of

Figure 21. U.S. tight oil production in four cases, 2005-40 (million barrels per day)

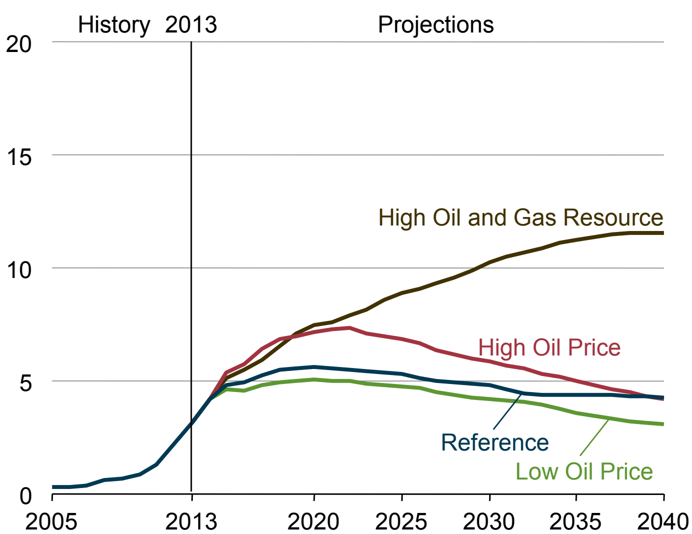
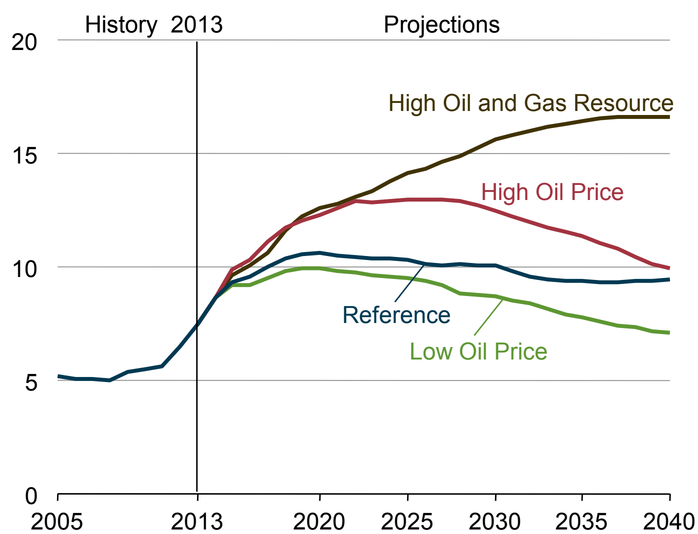


Figure 22. U.S. total crude oil production in four cases, 2005-40 (million barrels per day)



[26] West Texas Intermediate is a crude stream produced in Texas and southern Oklahoma that serves as a reference, or marker, for pricing a number of other crude streams and is traded in the domestic spot market at Cushing, Oklahoma.

formations, which have smaller estimated ultimate recoveries (EURs) than wells drilled in core areas. As a result, they have a more limited impact on total production growth in the near term.

In both the High Oil and Gas Resource and High Oil Price cases, growing production of 27°–35° American Petroleum Institute (API) medium sour crude oil from the offshore Gulf of Mexico (GOM) helps balance the crude slate when combined with the increasing production of light, sweet crude from tight oil formations. In all cases, GOM crude oil production increases through 2019, as offshore deepwater projects have relatively long development cycles that have already begun. GOM production declines through at least 2025 in all cases and fluctuates thereafter as a result of the timing of large, discrete discoveries that are brought into production. Overall GOM production through 2040 is highest in the High Oil and Gas Resource case, followed closely by the High Oil Price case and finally by the Reference case and Low Oil Price case.

In the High Oil Price case, producers take greater advantage of CO2-enhanced oil recovery (CO2-EOR) technologies. CO2-EOR production increases at a steady pace over the projection period in the Reference case and increases more dramatically in the High Oil Price case, where higher prices make additional CO2-EOR projects economically viable. In the High Oil and Gas Resource and Low Oil Price cases, with lower crude oil prices, fewer CO2-EOR projects are economical than in the Reference case.

Production of natural gas plant liquids (NGPL), including ethane, propane, butane, isobutane, and natural gasoline, increases from 2013 to 2023 in all the AEO2015 cases. After 2023, only the High Oil and Gas Resource case shows increasing NGPL production through the entire projection period. However, the High Oil Price case also shows significant NGPL production growth through 2026. Most of the early growth in NGPL production is associated with the continued development of liquids-rich areas in the Marcellus, Utica, and Eagle Ford formations.

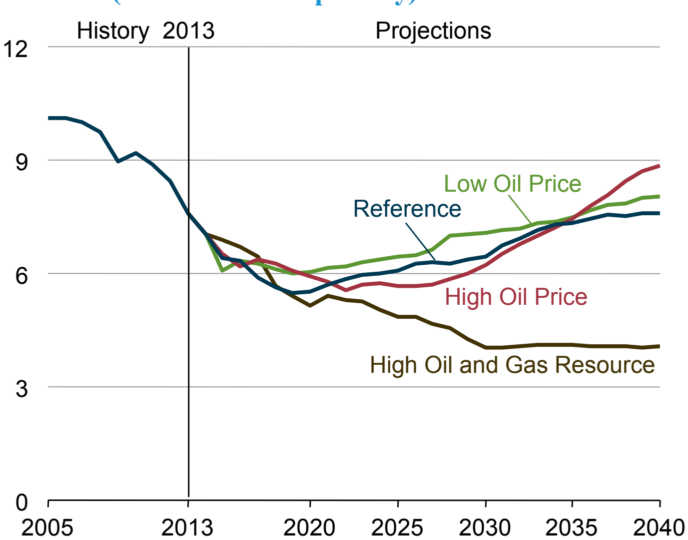
Production of petroleum products at U.S. refineries depends largely on the cost of crude oil, domestic demand, and the absorption of petroleum product exports in foreign markets. U.S. refinery production of gasoline blending components declines in the Reference and Low Oil Price cases but increases in the High Oil Price and High Oil and Gas Resource cases. The steepest decline in production of motor gasoline blending components is projected in the Reference case, with production of blending components declining from 7.9 million bbl/d in 2013 to 7.2 million bbl/d in 2040, in response to a drop in U.S. crude oil production, higher crude oil prices, and lower demand. In the High Oil and Gas Resource case, production of blending components increases to 9.1 million bbl/d in 2040, because abundant domestic supply of lighter crude oil results in lower feedstock costs for refiners, lower gasoline prices, increased exports, and relatively higher levels of gasoline consumption (including exports) and production.

Diesel fuel output from U.S. refineries rises in the High Oil and Gas Resource case from 4.2 million bbl/d in 2013 to 6.6 million bbl/d in 2037, as a result of lower costs for refinery feedstocks. In the Low Oil Price case, lower domestic diesel fuel prices result in higher levels of domestic consumption, leading to a 4.7 million bbl/d increase in diesel fuel production in 2040. In the High Oil Price case, higher oil prices (which are assumed to occur worldwide) make diesel fuel from U.S. refineries more competitive. Total U.S. diesel fuel output increases to 6.1 million bbl/d in 2040. In the Reference case, U.S. diesel fuel output increases to 5.3 million bbl/d in 2040.

As in the Reference case, the United States remains a net importer of liquid fuels through 2040 in the Low Oil Price case. In the High Oil and Gas Resource case, as a result of higher levels of both domestic crude oil production and petroleum product exports, the United States becomes a net exporter of liquid fuels by 2021. Refiners and oil producers gain a competitive advantage from abundant domestic supply of light crude oil and higher GOM production of lower API crude oil streams, along with lower refinery fuel costs as a result of abundant domestic natural gas supply. In the High Oil Price case, the United States becomes a net exporter of liquid fuels in 2020, as higher oil prices reduce U.S. consumption of petroleum products and spur additional U.S. crude oil production. U.S. net crude oil imports—which fall to 5.5 million bbl/d in 2022 as domestic crude oil production grows—rise to 8.9 million bbl/d in 2040 as domestic production flattens and begins to decline.

By 2040, the level of net liquid fuels exports is significantly larger in the High Oil and Gas Resource case than in the High Oil Price case. In the High Oil Price case, higher world crude oil prices make overseas refineries less competitive compared to U.S. refineries. As a result, net U.S. exports of petroleum products increase by more in the High Oil Price case than in the High Oil and Gas Resource case. However, the availability of more domestic crude oil resources in the High Oil and Gas Resource case results in a significantly greater drop in net crude oil imports and a larger overall swing in liquid fuels trade than in any of the other AEO2015 cases (Figure 23 and Figure 24).

Figure 23. U.S. net crude oil imports in four cases, 2005-40 (million barrels per day)



In the High Oil and Gas Resource case, the United States swings from net liquid fuels imports equal to 33% of total domestic product supplied in 2013 to net liquid fuels exports equal to 29% of total domestic product supplied in 2040 (compared with net exports equal to 3% of total domestic product supplied in 2040 in the High Oil Price case). In the Reference case, net imports fall to 14% of total domestic product supplied in 2020, before rising to nearly 18% of product supplied in 2033 and remaining around that level through 2040. Net imports of liquid fuels fall to 19% of total product supplied in 2020 in the Low Oil Price case before rising to 36% of total product supplied in 2040.

Cheaper light crude oil production from inland basins and increased production of heavier GOM crude oil leads to a 35% decline in gross crude oil imports in the High Oil and Gas Resource case—from 7.7 million bbl/d in 2013 to 5.0 million bbl/d in 2040. This compares with a 6% increase in the Reference case (to 8.2 million bbl/d in 2040) and a 12% increase in the Low Oil Price case (to 8.7 million bbl/d in 2040).

Net petroleum product exports increase as U.S. refineries become more competitive in all cases except for the Low Oil Price case. Net petroleum product exports increase most in the High Oil Price and High Oil and Gas Resource cases (from 1.4 million bbl/d in 2013 to 9.5 million bbl/d and 9.9 million bbl/d, respectively, in 2040). In the Reference case, net petroleum product exports increase to 4.3 million bbl/d in 2040, and in the Low Oil Price case they increase to 2.2 million bbl/d in 2020 and then decline to 0.7 million bbl/d in 2040.

In the High Oil and Gas Resource case, gross crude oil exports allowed under current laws and regulations, including exports to Canada and exports of processed condensate, rise significantly in response to increased production. It is assumed that condensate which has been processed through a distillation tower can be exported in accordance with a clarification from the U.S. Department of Commerce, Bureau of Industry and Security.[27] Gross crude exports increase from 0.1 million bbl/d in 2013 to a high of 1.3 million bbl/d in 2027 in the High Oil and Gas Resource case, before declining to 0.9 million bbl/d in 2040—compared with 0.6 million bbl/d in 2040 in the Reference, High Oil Price, and Low Oil Price cases. With U.S. refinery access to increased amounts of low-cost domestic crude supplies, gross petroleum product exports increase from 3.4 million bbl/d in 2013 to 12.0 million bbl/d in the High Oil and Gas Resource case and to 11.5 million bbl/d in 2040 in the High Oil Price case, compared with 6.4 million bbl/d in the Reference case and 3.5 million bbl/d in the Low Oil Price case.

Natural gas

Production

Total dry natural gas production in the United States increased by 35% from 2005 to 2013, with the natural gas share of total U.S. energy consumption rising from 23% to 28%. Production growth resulted largely from the development of shale gas resources in the Lower 48 states (including natural gas from tight oil formations), which more than offset declines in other Lower 48 onshore production. In the AEO2015 Reference case, more than half of the total increase in shale gas production over the projection period comes from the Haynesville and Marcellus formations. Lower 48 shale gas production (including natural gas from tight oil formations) increases by 73% in the Reference case, from 11.3 Tcf in 2013 to 19.6 Tcf in 2040, leading to a 45% increase in total U.S. dry natural gas production, from 24.4 Tcf in 2013 to 35.5 Tcf in 2040. Growth in tight gas, federal offshore, and onshore Alaska production also contributes to overall production growth over the projection period (Figure 25 and Figure 26).

Figure 24. U.S. net petroleum product imports in four cases, 2005-40 (million barrels per day)

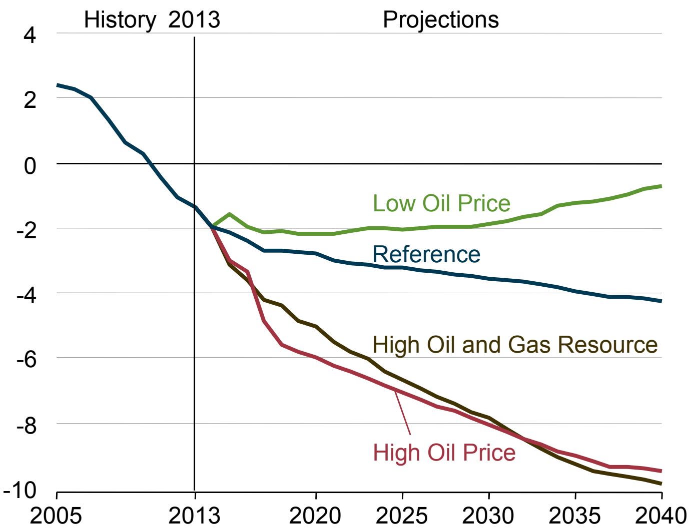
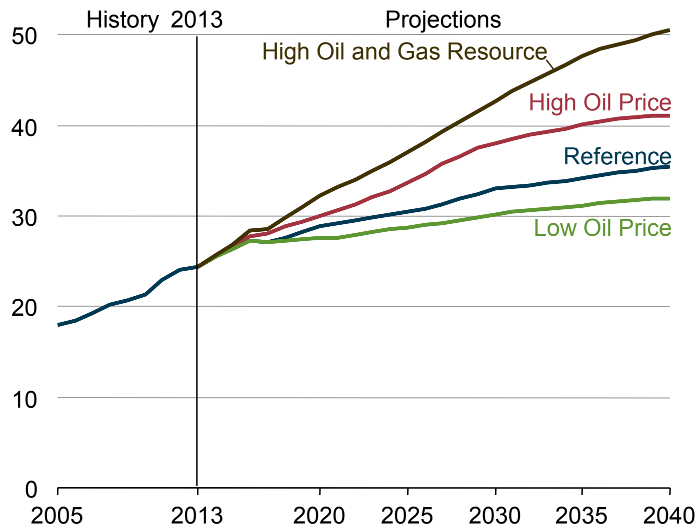


Figure 25. U.S. total dry natural gas production in four cases, 2005-40 (trillion cubic feet)



[27] U.S. Department of Commerce, Bureau of Industry and Security, "FAQs–Crude Oil and Petroleum Products December 30, 2014" (see question no. 3, "Is lease condensate considered crude oil?") (Washington, DC: December 30, 2014), http://www.bis.doc.gov/index.php/policy-guidance/faqs.

Future dry natural gas production depends primarily on the size and cost of tight and shale gas resources, technology improvements, domestic natural gas demand, and the relative price of oil. Projections in the High Oil and Gas Resource case assume closer well spacing; higher EURs per shale gas well, tight gas well, and tight oil well; development of new tight oil formations either from new discoveries or additional layers within known tight oil formations; and additional long-term technology improvements that further increase the EUR per tight gas and shale gas well over the projection period above those in the Reference case. Even with lower prices, total U.S. dry natural gas production increases in the High Oil and Gas Resource case to 50.6 Tcf in 2040, 43% above the Reference case level, with Lower 48 shale gas production of 34.6 Tcf in 2040, or 77% above the Reference case level.

The High and Low Oil Price cases use the same natural gas resource assumptions as the Reference case, but production levels vary in response to natural gas demand, primarily from the transportation sector and global demand for U.S.-origin LNG. In the High Oil Price case, increased demand for natural gas as a fuel for motor vehicles, as LNG for export, and as plant fuel for natural gas liquefaction facilities accounts for the increase in total domestic dry natural gas production to 41.1 Tcf in 2040 (16% above the Reference case). U.S. shale gas production in the High Oil Price case totals 23.6 Tcf in 2040, 21% above the Reference case total. In the Low Oil Price case, with lower demand for natural gas and LNG exports, U.S. dry natural gas production totals 31.9 Tcf in 2040 (10% below the Reference case total), and U.S. shale gas production totals 18.1 Tcf in 2040 (8% below the Reference case).

Tight gas accounts for a smaller, but still significant, portion of the increase in U.S. dry natural gas production compared to shale gas. Tight gas production responds largely to crude oil prices and the same levels of technological progress experienced with shale gas production. Tight gas production increases from 4.4 Tcf in 2013 to 7.0 Tcf in 2040 in the Reference case, compared with 8.1 Tcf in 2040 in the High Oil and Gas Resource case, 8.4 Tcf in the High Oil Price case, and 6.6 Tcf in the Low Oil Price case. Most of the tight gas production growth occurs in the Gulf Coast and Dakotas/Rocky Mountains regions. Tight gas production in the Midcontinent region—which declines in the Reference case—increases by 24% from 2013 to 2040 in the High Oil and Gas Resource case.

Undiscovered crude oil and natural gas resources in the federal offshore and Alaska regions are assumed to be 50% higher in the High Oil and Gas Resource case than in the Reference case. Lower 48 offshore natural gas production increases from 1.5 Tcf in 2013 to 3.0 Tcf in 2040 in the High Oil and Gas Resource case, and to 2.8 Tcf in 2040 in both the High Oil Price and Reference cases. Cumulative federal offshore natural gas production is highest in the High Oil Price case, with federal offshore natural gas production increasing more than in any of the other AEO2015 cases through 2036, before declining. Alaska dry natural gas production begins increasing in 2026 in the High Oil Price case, and in 2027 in the Reference case. Alaska dry natural gas production reaches 1.2 Tcf in 2029 and remains at that level through 2040 in the High Oil Price case. Alaskan production reaches 1.1 Tcf in 2040 in the Reference case, following the projected completion of a new LNG export facility in Alaska. In the Low Oil Price and High Oil and Gas Resource cases, lower international natural gas prices make LNG exports from Alaska uneconomical, and Alaska dry natural gas production falls through 2040 as declines in oil production result in decreased use of natural gas for drilling operations.

Imports and exports

In all the AEO2015 cases, net natural gas imports continue to decline through 2040, as they have since 2007. Gross exports of natural gas increase over the period, and gross imports decline. The rate of decline in net imports varies across the cases—depending on assumptions about changes in world oil prices and U.S. natural gas resources—and slows in the later years of the projections (Figure 27). In all the cases, the United States becomes a net exporter of natural gas in 2017, driven by LNG exports (Figure 28), increased pipeline exports to Mexico, and reduced imports from Canada.

Figure 26. U.S. shale gas production in four cases, 2005-40 (trillion cubic feet)

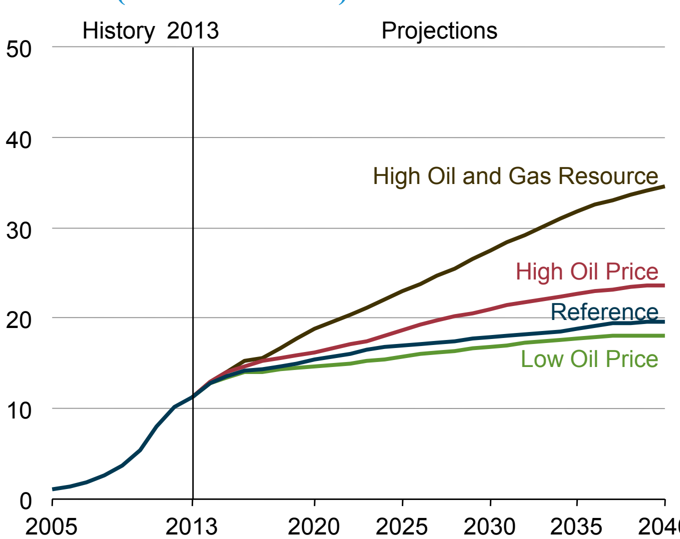
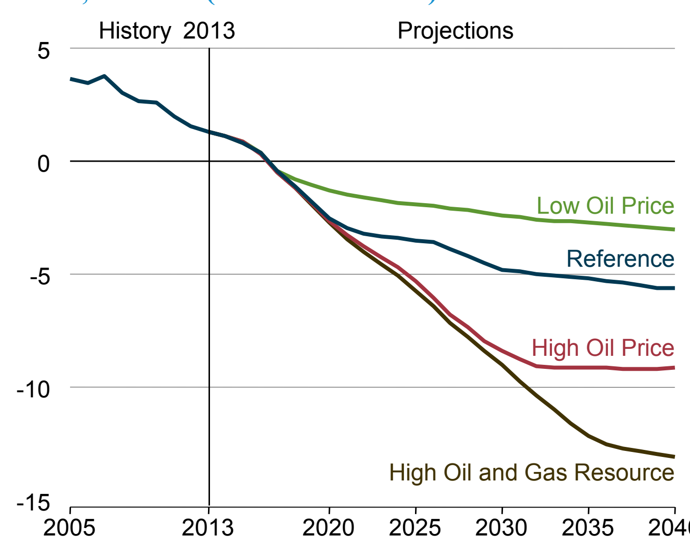


Figure 27. U.S. total natural gas net imports in four cases, 2005-40 (trillion cubic feet)



In the Reference case, net exports of natural gas from the United States total 5.6 Tcf in 2040. Most of the growth in U.S. net natural gas exports occurs before 2030, when gross liquefied natural gas (LNG) exports reach their highest level of 3.4 Tcf, where they remain through 2040. In all the cases, the United States remains a net pipeline importer of natural gas from Canada through 2040, but at lower levels than in recent history, while net pipeline exports of natural gas to Mexico grow from 0.7 Tcf in 2013 to 3.0 Tcf in 2040 in the Reference case.

The price of LNG supplied to international markets, which in part reflects world oil prices, is significantly higher than the price of U.S. domestic natural gas supply, particularly in the near term. The growth in U.S. LNG exports is driven by this price difference, which also discourages U.S. LNG imports. LNG export growth after 2020 is highest in the High Oil and Gas Resource case, where higher production capability lowers the price of U.S. natural gas supply to the world market, leading to net LNG exports of 10.3 Tcf in 2040 (212% more than in the Reference case) and total net natural gas exports of 13.1 Tcf in 2040 (133% more than in the Reference case).

Most of the variations in projected net exports of U.S. natural gas among the AEO2015 cases result from differences in levels of LNG exports. In the High Oil Price and Low Oil Price cases, projected LNG exports vary in response to differences between international and domestic natural gas prices, after accounting for the costs associated with processing and transporting the gas. Over the projection, the relationship between international LNG prices and world oil prices is assumed to weaken, particularly as U.S. LNG exports increase. Low world oil prices limit the competitiveness of domestic natural gas relative to oil itself and also to LNG volumes sold through contracts linked to oil prices, which are less likely to be renegotiated in a low oil price environment.

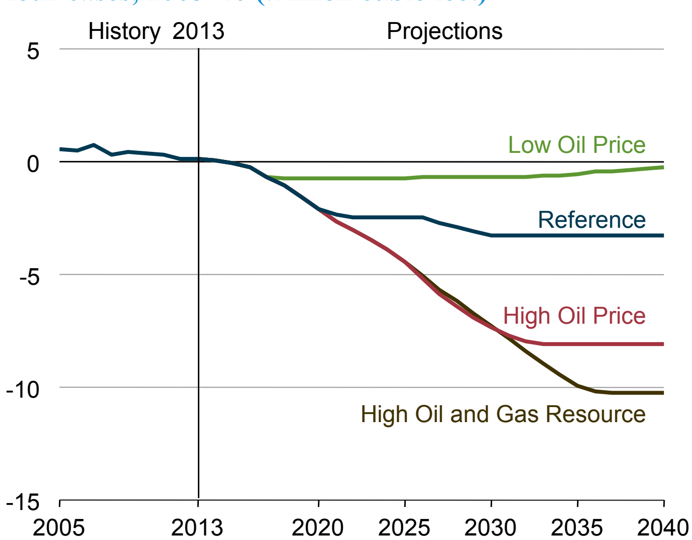
In the High Oil Price case, U.S. LNG exports total 8.1 Tcf in 2040, or 142% more than in the Reference case. As a result, U.S. net natural gas exports total 9.1 Tcf in 2040 in the High Oil Price case, or 63% more than in the Reference case. In the Low World Oil Price case, LNG net exports never surpass 0.8 Tcf, and U.S. net exports of natural gas total 3.0 Tcf in 2040, or 46% below the Reference case level.

Canada, which accounted for 97% of total U.S. pipeline imports of natural gas in 2013, continues as the source of nearly all U.S. pipeline imports through 2040. Most natural gas imported into the United States comes from western Canada and is delivered mainly to the West Coast and the Midwest.

In the AEO2015 alternative cases, gross pipeline imports from Canada generally are higher than in the Reference case when prices in the United States are higher, and vice versa. However, gross pipeline imports from Canada in 2040 are highest in the High Oil and Gas Resource case, with growth after 2030 resulting from an assumed increase in Canada's shale and coalbed resources. Gross exports of U.S. natural gas to Canada, largely into the eastern provinces, generally increase when prices are low in the United States, and vice versa.

U.S. pipeline exports of natural gas—most flowing south to Mexico—have grown substantially since 2010 and are projected to continue increasing in all the AEO2015 cases because increases in Mexico's production are not expected to keep pace with the country's growing demand for natural gas, primarily for electric power generation. In the High Oil and Gas Resource case, with the lowest projected U.S. natural gas prices, pipeline exports to Mexico in 2040 total 4.7 Tcf, as compared with 3.3 Tcf in the Low Oil Price case and 2.2 Tcf by 2040 in the High Oil Price case.

Figure 28. U.S. liquefied natural gas net imports in four cases, 2005-40 (trillion cubic feet)



Coal

Between 2008 and 2013, U.S. coal production fell by 187 million short tons (16%), as declining natural gas prices made coal less competitive as a fuel for generating electricity (Figure 29). In the AEO2015 Reference case, U.S. coal production increases at an average rate of 0.7%/year from 2013 to 2030, from 985 million short tons (19.9 quadrillion Btu) to 1,118 million short tons (22.4 quadrillion Btu). Over the same period, rising natural gas prices, particularly after 2017, contribute to increases in electricity generation from existing coal-fired power plants as coal prices increase more slowly. After 2030, coal consumption for electricity generation levels off through 2040. The cases presented in AEO2015 do not include EPA's proposed Clean Power Plan, which would have a material impact on projected levels of coal-fired generation. A separate EIA analysis of the Clean Power Plan is forthcoming.

Compliance with the Mercury and Air Toxics Standards (MATS),[28] coupled with low natural gas prices and

[28]U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," http://www.epa.gov/mats (Washington, DC: March 27, 2012).

competition from renewables, leads to the projected retirement of 31 gigawatts (GW) of coal-fired generating capacity and the conversion of 4 GW of coal-fired generating capacity to natural gas between 2014 and 2016. However, coal consumption in the U.S. electric power sector is supported by an increase in output from the remaining coal-fired power plants, with the projected capacity factor for the U.S. coal fleet increasing from 60% in 2013 to 67% in 2016. In the absence of any significant additions of coal-fired electricity generating capacity, coal production after 2030 levels off as many existing coal-fired generating units reach maximum capacity factors and coal exports grow slowly. Total U.S. coal production in the AEO2015 Reference case remains below its 2008 level through 2040.

Across the AEO2015 alternative cases, the largest changes in U.S. coal production relative to the Reference case occur in the High Oil and Gas Resource and High Oil Price cases. In the High Oil and Gas Resource case, lower natural gas prices lead to a significant shift away from the use of coal in the electric power sector, resulting in coal production levels that are 13% lower in 2020 and 11% lower in 2040 than in the Reference case. In the High Oil Price case, higher oil prices spur investments in coal-based synthetic fuels, which result in increasing demand for domestically produced coal, primarily from mines in the Western supply region. In the High Oil Price case, coal consumption at coal-to-liquids (CTL) plants rises from 11 million short tons in 2025 to 181 million short tons in 2040, and total coal production in 2040 is 13% higher than in the Reference case.

In the other AEO2015 cases, variations in the quantities of coal produced relative to the Reference case are more modest, ranging from 4% (49 million short tons) lower in the Low Economic Growth case to 4% (40 million short tons) higher in the High Economic Growth case in 2040. Factors that limit the variation in U.S. coal production across cases include the high capital costs associated with building new coal-fired generating capacity, which limit potential growth in coal use; the relatively low operating costs of existing coal-fired units, which tend to limit the decline in coal use; and limited potential to increase coal use at existing generating units, which already are at maximum utilization rates in some regions.

Changes in assumptions about the rate of economic growth also affect the outlook for coal demand in the U.S. industrial sector (coke and other industrial plants) and, consequently, coal production. In the Low Economic Growth case, lower levels of industrial coal consumption in 2040 account for 17% of the reduction in total coal consumption relative to the Reference case. In the High Economic Growth case, higher levels of coal consumption in the industrial sector in 2040 account for 44% of the increase in total coal consumption relative to the Reference case.

Regionally, strong production growth in the Interior region contrasts with declining production in the Appalachian region in the AEO2015 Reference case. In the Interior region, coal production becomes increasingly competitive as a result of a combination of improving labor productivity and the installation of scrubbers at existing coal-fired power plants, which allows those plants to burn the region's higher-sulfur coals at a lower delivered cost compared with coal from other regions. Appalachian coal production declines in the Reference case, as coal produced from the extensively mined, higher-cost reserves of Central Appalachia is replaced by lower-cost coals from other regions. Western coal production in the Reference case increases from 2017 to 2024, in line with the increase in U.S. consumption, but falls slightly thereafter as a result of competition from producers in the Interior region and limited growth in coal use at existing coal-fired power plants after 2025.

U.S. coal exports decline from 118 million short tons in 2013 to 97 million short tons in 2014 and to 82 million short tons in 2015 in the AEO2015 Reference case, then increase gradually to 141 million short tons in 2040 (Figure 30). Much of the growth in exports after 2015 is attributable to increased exports of steam coal from mines in the Interior and Western regions. Between 2015 and 2040, U.S. steam coal exports increase by 42 million short tons, and coking coal exports increase by 17 million short tons.

Figure 29. U.S. coal production in six cases, 1990-2040 (million short tons)

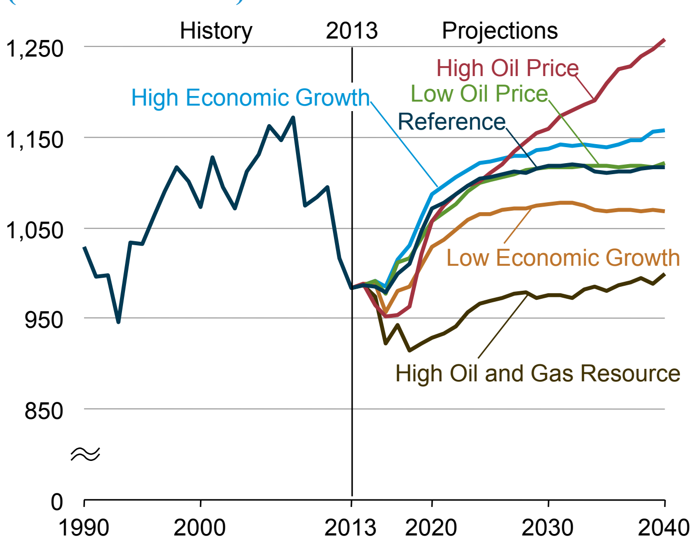
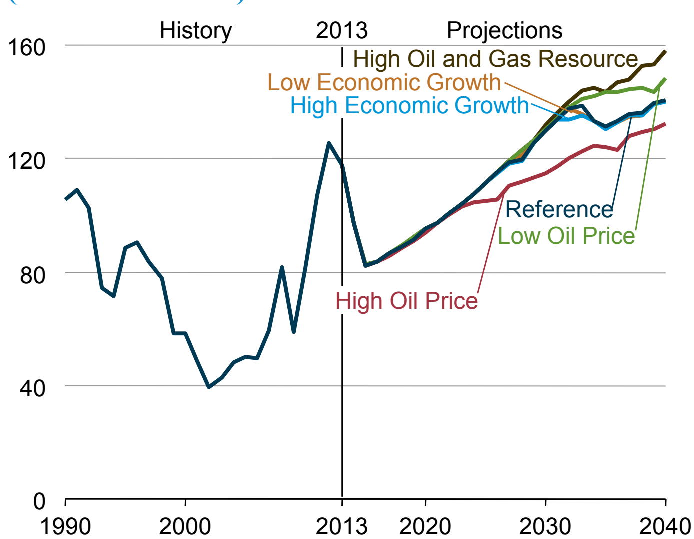


Figure 30. U.S. coal exports in six cases, 1990-2040 (million short tons)



Across the AEO2015 alternative cases, U.S. coal exports in 2040 vary from a low of 132 million short tons in the High Oil Price case (6% lower than in the Reference case) to a high of 158 million short tons in the High Oil and Gas Resource case (12% higher than in the Reference case). Coal exports are also higher in the Low Oil Price case than in the Reference case, increasing to 149 million short tons in 2040. In the Low and High Oil Price cases, variations in the prices of diesel fuel and electricity, which are two important inputs to coal mining and transportation, are key factors affecting U.S. coal exports. The projections of lower and higher fuel prices for coal mining and transportation affect the relative competiveness of U.S. coal in international coal markets. In the High Oil and Gas Resource case, the combination of lower prices for diesel fuel and electricity and lower domestic demand for coal contribute to higher export projections relative to the Reference case.

Electricity generation

Total electricity use in the AEO2015 Reference case, including both purchases from electric power producers and on-site generation, grows by an average of 0.8%/year, from 3,836 billion kilowatthours (kWh) in 2013 to 4,797 billion kWh in 2040. The relatively slow rate of growth in demand, combined with rising natural gas prices, environmental regulations, and continuing growth in renewable generation, leads to tradeoffs between the fuels used for electricity generation. From 2000 to 2012, electricity generation from natural gas-fired plants more than doubled as natural gas prices fell to relatively low levels. In the AEO2015 Reference case, natural gas-fired generation remains below 2012 levels until after 2025, while generation from existing coal-fired plants and new nuclear and renewable plants increases (Figure 31). In the longer term, natural gas fuels more than 60% of the new generation needed from 2025 to 2040, and growth in generation from renewable energy supplies most of the remainder. Generation from coal and nuclear energy remains fairly flat, as high utilization rates at existing units and high capital costs and long lead times for new units mitigate growth in nuclear and coal-fired generation. Considerable variation in the fuel mix results when fuel prices or economic conditions differ from those in the Reference case.

AEO2015 assumes the implementation of the Mercury and Air Toxics Standards (MATS) in 2016, which regulates mercury emissions and other hazardous air pollutants from electric power plants. Because the equipment choices to control these emissions often reduce sulfur dioxide emissions as well, by 2016 sulfur dioxide emissions in the Reference case are well below the levels required by both the Clean Air Interstate Rule (CAIR)[29] and the Cross-State Air Pollution Rule (CSAPR). [30,31]

Total electricity generation increases by 24% from 2013 to 2040 in the Reference case but varies significantly with different economic assumptions, ranging from a 15% increase in the Low Economic Growth case to a 37% increase in the High Economic Growth case. Coal-fired generation is similar across most of the cases in 2040, except the High Oil and Gas Resource case, which is the only one that shows a significant decline from the Reference case, and the High Oil Price case, which is the only one showing a large increase (Figure 32). The coal share of total electricity generation drops from 39% in 2013 to 34% in 2040 in the Reference

Figure 31. Electricity generation by fuel in the Reference case, 2000-2040 (trillion kilowatthours)

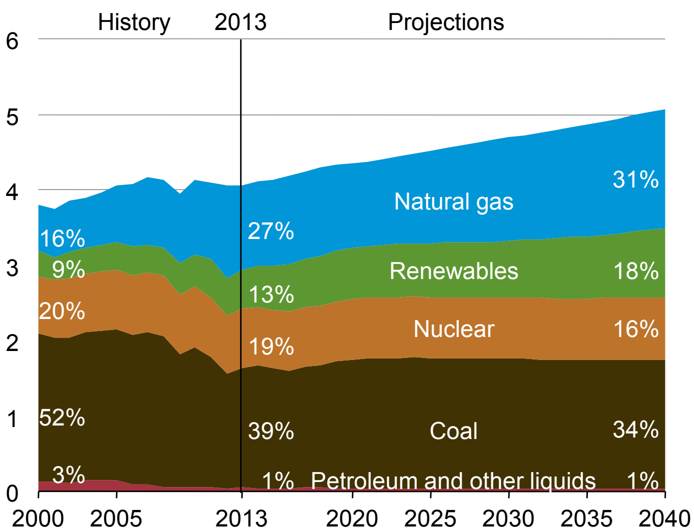
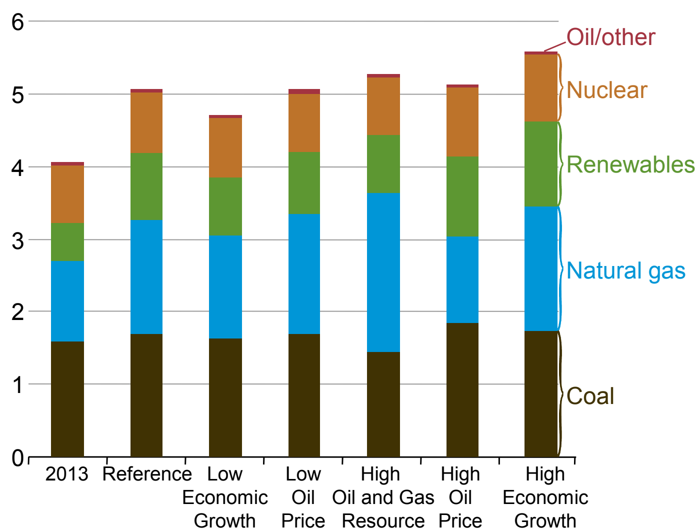


Figure 32. Electricity generation by fuel in six cases, 2013 and 2040 (trillion kilowatthours)



[29]U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: February 5, 2015), http://www.epa.gov/airmarkets/programs/cair/.

[30]U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)" (Washington, DC: October 23, 2014), http://www.epa.gov/airtransport/CSAPR.

[31]The AEO2015 Reference case assumes implementation of the Clean Air Interstate Rule (CAIR), which has been replaced by the Cross-State Air Pollution Rule (CSAPR) following a recent D.C. Circuit Court of Appeals decision to lift a stay on CSAPR. Although CAIR and CSAPR are broadly similar, future AEOs will incorporate CSAPR, absent further court action to stay its implementation.

case but still accounts for the largest share of total generation. When natural gas prices are lower than those in the Reference case, as in the High Oil and Gas Resource case, the coal share of total electricity generation drops below the natural gas share by 2020. When total electricity generation is reduced in the Low Economic Growth case, and as a result there is less need for new generation capacity, coal-fired generation maintains a larger share of the total.

Total natural gas-fired generation grows by 40% from 2013 to 2040 in the AEO2015 Reference case—and the natural gas share of total generation grows from 27% to 31%—with most of the growth occurring in the second half of the projection period. The natural gas share of total generation varies by AEO2015 case, depending on fuel prices; however, its growth is also supported by limited potential to increase coal use at existing coal-fired generating units, which in some regions are already at maximum utilization rates. In the High Oil Price case, the natural gas share of total electricity generation in 2040 drops to 23%. In the High Oil and Gas Resource case, with delivered natural gas prices 44% below those in the Reference case, the natural gas share of total generation in 2040 is 42%. Lower natural gas prices in the High Oil and Gas Resource case result in the addition of new natural gas-fired capacity, as well as increased operation of combined-cycle plants, which displace some coal-fired generation. The average capacity factor of natural gas combined-cycle plants is more than 60% in the High Oil and Gas Resource case, compared with an average capacity factor of around 50% in the Reference case (Figure 33), while the average capacity factor of coal-fired plants is lower in the High Oil and Gas Resource case than in the Reference case.

Electricity generation from nuclear units across the cases reflects the impacts of planned and unplanned builds and retirements. Nuclear power plants provided 19% of total electricity generation in 2013. From 2013 to 2040, the nuclear share of total generation declines in all cases, to 15% in the High Oil and Gas Resource case and to 18% in the High Oil Price case, where higher natural gas prices lead to additional growth in nuclear capacity.

Renewable generation grows substantially from 2013 to 2040 in all the AEO2015 cases, with increases ranging from less than 50% in the High Oil and Gas Resource and Low Economic Growth cases to 121% in the High Economic Growth case. State and national policy requirements play an important role in the continuing growth of renewable generation. In the Reference case, the largest growth is seen for wind and solar generation (Figure 34). In 2013, as a result of increases in wind and solar generation, total nonhydropower renewable generation was almost equal to hydroelectric generation for the first time. In 2040, nonhydropower renewable energy sources account for more than two-thirds of the total renewable generation in the Reference case. The total renewable share of all electricity generation increases from 13% in 2013 to 18% in 2040 in the Reference case and to as much as 22% in 2040 in the High Oil Price case. With lower natural gas prices in the High Oil and Gas Resource case, the renewable generation share of total electricity generation grows more slowly but still increases to 15% of total generation in 2040.

Total electricity generation capacity, including capacity in the end-use sectors, increases from 1,065 GW in 2013 to 1,261 GW in 2040 in the AEO2015 Reference case. Over the first 10 years of the projection, capacity additions are roughly equal to retirements, and the level of total capacity remains relatively flat as existing capacity is sufficient to meet expected demand. Capacity additions between 2013 and 2040 total 287 GW, and retirements total 90 GW. From 2018 to 2024, capacity additions average less than 4 GW/year, as earlier planned additions are sufficient to meet most demand growth. From 2025 to 2040, average annual capacity additions—primarily natural gas-fired and renewable technologies—average 12 GW/year. The mix of capacity types added varies across the cases, depending on natural gas prices (Figure 35).

Figure 33. Coal and natural gas combined-cycle generation capacity factors in two cases, 2010-40 (percent)

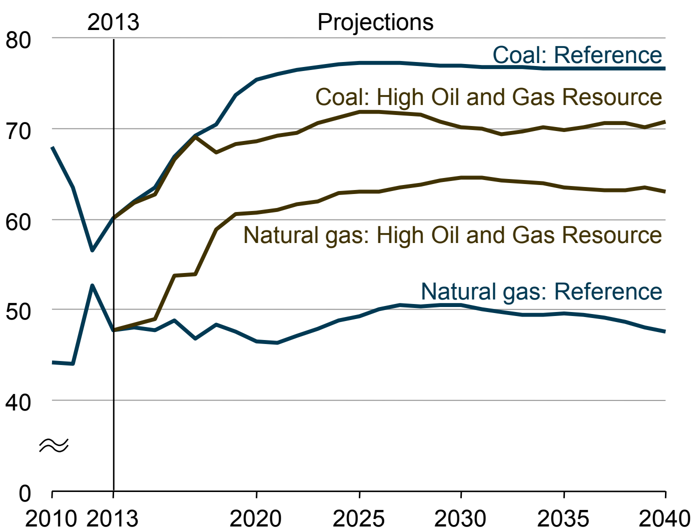


Figure 34. Renewable electricity generation by fuel type in the Reference case, 2000-2040 (billion kilowatthours)

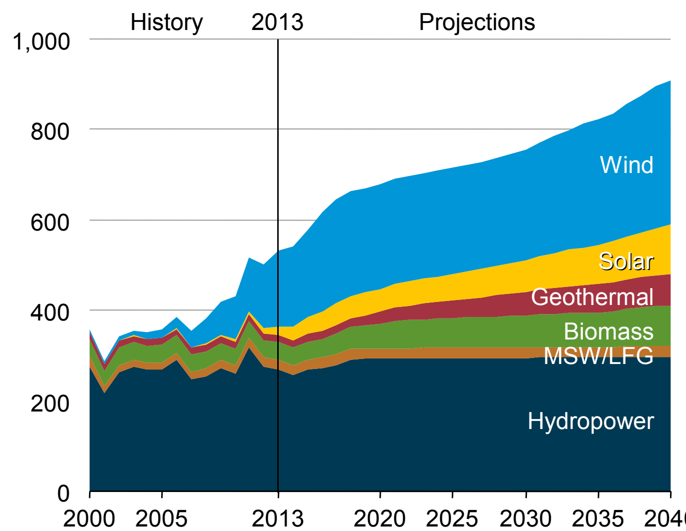
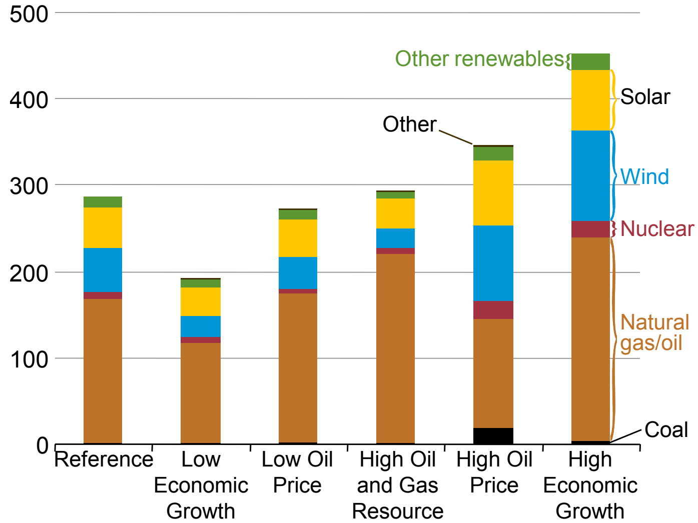


Figure 35. Cumulative additions to electricity generation capacity by fuel in six cases, 2013-40 (gigawatts)



In recent years, natural gas-fired capacity has grown considerably. In particular, combined-cycle plants are relatively inexpensive to build in comparison with new coal, nuclear, or renewable technologies, and they are more efficient to operate than existing natural gas-, oil- or coal-fired steam plants. Natural gas turbines are the most economical way to meet growth for peak demand. In most of the AEO2015 cases, the growth in natural gas capacity continues. Natural gas-fired plants account for 58% of total capacity additions from 2013 to 2040 in the Reference case, and they represent more than 50% of additions in all cases, except for the High Oil Price case, where higher fuel prices for natural gas-fired plants reduce their competitiveness, and only 36% of new builds are gas-fired. With lower fuel prices in the High Oil and Gas Resource case, natural gas-fired capacity makes up three-quarters of total capacity additions.

Coal-fired capacity declines from 304 GW in 2013 to 260 GW in 2040 in the Reference case, as a result of retirements and very few new additions. A total of 40 GW of coal capacity is retired from 2013 to 2040 in the Reference case, representing both announced retirements and those projected on the basis of relative economics, including the costs of meeting environmental regulations and competition with natural gas-fired generation in the near term. As a result of the uncertainty surrounding future greenhouse gas legislation and regulations and given its high capital costs, very little unplanned coal-fired capacity is added across all the AEO2015 cases. About 19 GW of new coal-fired capacity is added in the High Oil Price case, but much of that is associated with CTL plants built in the refinery sector in response to higher oil prices.

Renewables account for more than half the capacity added through 2022, largely to take advantage of the current production tax credit and to help meet state renewable targets. Renewable capacity additions are significant in most of the cases, and in the Reference case they represent 38% of the capacity added from 2013 to 2040. The 109 GW of renewable capacity additions in the Reference case are primarily wind (49 GW) and solar (48 GW) technologies, including 31 GW of solar PV installations in the end-use sectors. The renewable share of total additions ranges from 22% in the High Oil and Gas Resource case to 51% in the High Oil Price case, reflecting the relative economics of natural gas-fired power plants, which are the primary choice for new generating capacity.

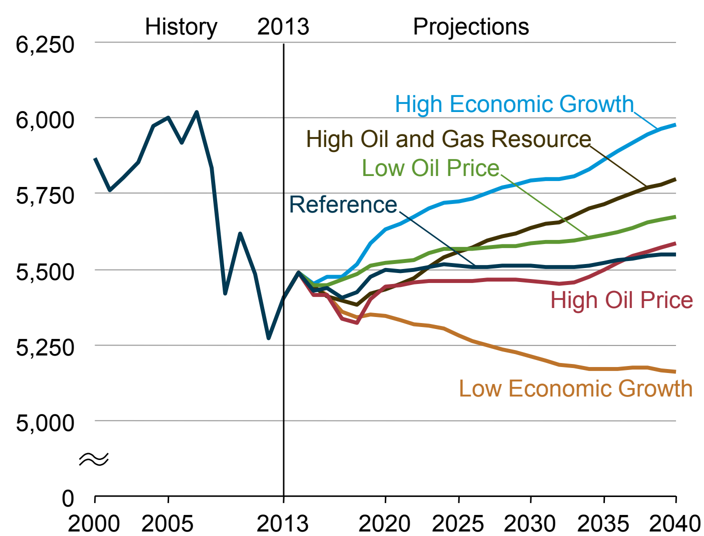
High construction costs for nuclear plants limit their competitiveness to meet new demand in the Reference case. In the near term, 5.5 GW of planned additions are put into place by 2020, offset by 3.2 GW of retirements over the same period. After 2025, 3.5 GW of additional nuclear capacity is built, based on relative economics. In the High Economic Growth and High Oil Price cases, an additional 10 GW to 13 GW of nuclear capacity above the Reference case is added by 2040 to meet demand growth, as a result of higher costs for the alternative technologies and/or higher capacity requirements.

Energy-related carbon dioxide emissions

In the AEO2015 Reference case projection, U.S. energy-related CO2 emissions are 5,549 million metric tons (mt) in 2040. Among the alternative cases, emissions totals show the greatest sensitivity to levels of economic growth (Figure 36), with 2040 totals varying from 5,979 million mt in the High Economic Growth case to 5,160 million mt in the Low Economic Growth case. In all the AEO2015 cases, emissions remain below the 2005 level of 5,993 million mt. As noted above, the AEO2015 cases do not assume implementation of EPA's proposed Clean Power Plan or other actions beyond current policies to limit or reduce CO2 emissions.

Emissions per dollar of GDP fall from the 2013 level in all the AEO2015 cases. In the Reference case, most of the decline is

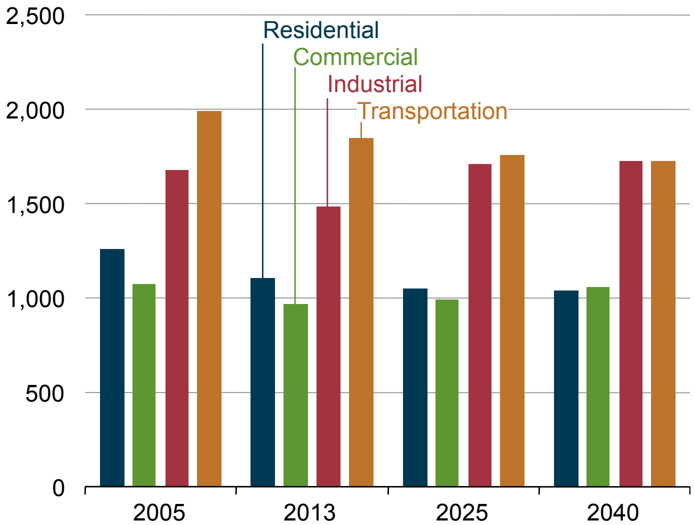
Figure 36. Energy-related carbon dioxide emissions in six cases. 2000-2040 (million metric tons)



attributable to a 2.0%/year decrease in energy intensity. In addition, the carbon intensity of the energy supply declines by 0.2%/year over the projection period.

The main factors influencing CO2 emissions include substitution of natural gas for coal in electricity generation, increases in the use of renewable energy, improvements in vehicle fuel economy, and increases in the efficiencies of appliances and industrial processes. In the Reference case, CO2 emissions growth varies across the end-use sectors (Figure 37). The highest annual growth rate (0.5%) is projected for the industrial sector, reflecting a resurgence of industrial production fueled mainly by natural gas. CO2 emissions in the commercial sector grow by 0.3%/year in the Reference case, while emissions in both the residential and transportation sectors decline on average by 0.2%/year.

Figure 37. Energy-related carbon dioxide emissions by sector in the Reference case, 2005, 2013, 2025, and 2040 (million metric tons)



In the alternative cases, various factors play roles in the emissions picture. In the High Economic Growth case, GDP increases annually by 2.9% and overshadows the decrease in energy intensity of 2.2%, leading to the largest annual rate of increase in CO2 emissions (0.4%/year). In the Low Economic Growth case, GDP grows by only 1.8%/year, and that growth is offset by a similar annual average decline in energy intensity. With the additional decline in the carbon intensity of the energy supply, CO2 emissions decline by 0.2%/year in the Low Economic Growth case.

Emissions levels also vary across the other alternative cases. The High Oil and Gas Resource case has the second-highest rate of emissions in 2040 (after the High Economic Growth case) at 5,800 million mt. In the Low Oil Price case, CO2 emissions total 5,671 million mt in 2040. In the High Oil Price case, emissions levels remain lower than projected in the Reference case throughout most of the period from 2013 to 2040, but energy-related CO2 emissions exceed the Reference case level by 35 million mt in 2040, at 5,584 million mt.

List of acronyms

AEO	Annual Energy Outlook
AEO2015	Annual Energy Outlook 2015
API	American Petroleum Institute
bbl	Barrels
bbl/d	Barrels per day
Brent	North Sea Brent
Btu	British thermal unit(s)
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CHP	Combined heat and power
CO2	Carbon dioxide
CPI	Consumer price index
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
E85	Motor fuel containing up to 85% ethanol
EIA	U.S. Energy Information Administration
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EUR	Estimated ultimate recovery
GDP	Gross domestic product
GTL	Gas-to-liquids
GW	Gigawatt(s)
HDV	Heavy-duty vehicle
HGL	Hydrocarbon gas liquids
kWh	Kilowatthour(s)
LDV	Light-duty vehicle
LNG	Liquefied natural gas
MARPOL	Marine pollution
MATS	Mercury and Air Toxics Standards
Mcf	Thousand cubic feet
MELs	Miscellaneous electric loads
mpg	Miles per gallon
mt	Metric ton(s)
NGPL	Natural gas plant liquids
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PV	Photovoltaic
RFS	Renewable fuel standard
Tcf	Trillion cubic feet
U.S.	United States
VMT	Vehicle miles traveled

Figure and table sources

Links current as of April 2015

Figure ES1. North Sea Brent crude oil spot prices in four cases, 2005-40: History: U.S. Energy Information Administration, Petroleum & Other Liquids, Europe Bent Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D. **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40: History: U.S. Energy Information Administration, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES3. U.S. net energy imports in six cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Table ES1. Growth of trade-related factors in the Reference case, 1983-2040: AEO2015 National Energy Modeling System, runs REF2015.D021915A.

Figure ES4. Net crude oil and petroleum product imports as a percentage of U.S. product supplied in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES5. U.S. total net natural gas imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES6. Change in U.S. Lower 48 onshore crude oil production by region in six cases, 2013-40: Projections: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure ES7. Delivered energy consumption for transportation in six cases, 2008-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure ES8. Total U.S. renewable generation in all sectors by fuel in six cases, 2013 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Table 1. Summary of AEO2015 cases: U.S. Energy Information Administration.

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Figure 2. Annual growth rates for industrial output in three cases, 2013-40: Projections: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

Table 3. Average annual growth of labor productivity, employment, income, and consumption in three cases: Projections: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

Figure 3. North Sea Brent crude oil spot prices in four cases, 2005-40: History: U.S. Energy Information Administration, Petroleum & Other Liquids, Europe Bent Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D. **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, and HIGHPRICE.D021915A.

Figure 4. Motor gasoline prices in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, and HIGHPRICE.D021915A.

Figure 5. Distillate fuel oil prices in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, and HIGHPRICE.D021915A.

Figure 6. Average Henry Hub spot prices for natural gas in four cases, 2005-40: History: U.S. Energy Information Administration, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 7. Average minemouth coal prices by region in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 8. Average delivered coal prices in six cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 9. Average retail electricity prices in six cases, 2013-40: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 10. Delivered energy consumption for transportation by mode in the Reference case, 2013 and 2040: History: U.S. Energy Information Administration, Natural Gas Annual 2013, DOE/EIA-0131(2013) (Washington, DC, October 2014). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 11. Delivered energy consumption for transportation in six cases, 2008-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 12. Industrial sector total delivered energy consumption in three cases, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

Figure 13. Industrial sector natural gas consumption for heat and power in three cases, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 14. Residential sector delivered energy consumption by fuel in the Reference case, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 15. Commercial sector delivered energy consumption by fuel in the Reference case, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Table 4. Residential households and commercial indicators in three AEO2015 cases, 2013 and 2040: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

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Figure 17. Commercial sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040: AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 18. Primary energy consumption by fuel in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 19. Energy use per capita and per 2009 dollar of gross domestic product, and carbon dioxide emissions per 2009 dollar of gross domestic product, in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 20. Total energy production and consumption in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 21. U.S. tight oil production in four cases, 2005-40: AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 22. U.S. total crude oil production in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 23. U.S. net crude oil imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 24. U.S. net petroleum product imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 25. U.S. total dry natural gas production in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 26. U.S. shale gas production in four cases, 2005-40: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 27. U.S. total natural gas net imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 28. U.S. liquefied natural gas net imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 29. U.S. coal production in six cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 30. U.S. coal exports in six cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 31. Electricity generation by fuel in the Reference case, 2000-2040: History: U.S. Energy Information Administration, Monthly Energy Review, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 32. Electricity generation by fuel in six cases, 2013 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 33. Coal and natural gas combined-cycle generation capacity factors in two cases, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Figure 34. Renewable electricity generation by fuel type in the Reference case, 2000-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 35. Cumulative additions to electricity generation capacity by fuel in six cases, 2013-40: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 36. Energy-related carbon dioxide emissions in six cases, 2000-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 37. Energy-related carbon dioxide emissions by sector in the Reference cases, 2005, 2013, 2025, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

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Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Production								
Crude oil and lease condensate	13.7	15.6	22.2	21.5	21.1	19.8	19.9	0.9%
Natural gas plant liquids	3.3	3.6	5.5	5.7	5.7	5.6	5.5	1.7%
Dry natural gas	24.6	25.1	29.6	31.3	33.9	35.1	36.4	1.4%
Coal[1]	20.7	20.0	21.7	22.2	22.5	22.5	22.6	0.5%
Nuclear / uranium[2]	8.1	8.3	8.4	8.5	8.5	8.5	8.7	0.2%
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.8	2.8	0.4%
Biomass[3]	4.0	4.2	4.4	4.6	4.6	4.7	5.0	0.7%
Other renewable energy[4]	1.9	2.3	3.2	3.4	3.6	4.1	4.6	2.7%
Other[5]	0.8	1.3	0.9	0.9	0.9	0.9	1.0	-1.0%
Total	**79.6**	**82.7**	**98.7**	**100.9**	**103.7**	**103.9**	**106.6**	**0.9%**
Imports								
Crude oil	18.7	17.0	13.6	14.9	15.7	17.7	18.2	0.3%
Petroleum and other liquids[6]	4.2	4.3	4.6	4.5	4.4	4.3	4.1	-0.2%
Natural gas[7]	3.2	2.9	1.9	1.7	1.6	1.5	1.7	-1.9%
Other imports[8]	0.3	0.3	0.1	0.1	0.1	0.1	0.1	-5.2%
Total	**26.4**	**24.5**	**20.2**	**21.3**	**21.7**	**23.6**	**24.1**	**-0.1%**
Exports								
Petroleum and other liquids[9]	6.5	7.3	11.2	12.0	12.6	13.3	13.7	2.4%
Natural gas[10]	1.6	1.6	4.5	5.2	6.4	6.8	7.4	5.9%
Coal	3.1	2.9	2.5	2.9	3.3	3.4	3.5	0.8%
Total	**11.2**	**11.7**	**18.1**	**20.1**	**22.4**	**23.4**	**24.6**	**2.8%**
Discrepancy[11]	**0.4**	**-1.6**	**-0.1**	**0.0**	**0.2**	**0.3**	**0.3**	**- -**
Consumption								
Petroleum and other liquids[12]	35.2	35.9	37.1	36.9	36.5	36.3	36.2	0.0%
Natural gas	26.1	26.9	26.8	27.6	28.8	29.6	30.5	0.5%
Coal[13]	17.3	18.0	19.2	19.3	19.2	19.0	19.0	0.2%
Nuclear / uranium[2]	8.1	8.3	8.4	8.5	8.5	8.5	8.7	0.2%
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.8	2.8	0.4%
Biomass[14]	2.8	2.9	3.0	3.2	3.2	3.2	3.5	0.7%
Other renewable energy[4]	1.9	2.3	3.2	3.4	3.6	4.1	4.6	2.7%
Other[15]	0.4	0.4	0.3	0.3	0.3	0.3	0.3	-0.7%
Total	**94.4**	**97.1**	**100.8**	**102.0**	**102.9**	**103.8**	**105.7**	**0.3%**
Prices (2013 dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	113	109	79	91	106	122	141	1.0%
West Texas Intermediate	96	98	73	85	99	116	136	1.2%
Natural gas at Henry Hub (dollars per million Btu)	2.79	3.73	4.88	5.46	5.69	6.60	7.85	2.8%
Coal (dollars per ton)								
at the minemouth[16]	40.5	37.2	37.9	40.3	43.7	46.7	49.2	1.0%
Coal (dollars per million Btu)								
at the minemouth[16]	2.01	1.84	1.88	2.02	2.18	2.32	2.44	1.0%
Average end-use[17]	2.63	2.50	2.54	2.71	2.84	2.96	3.09	0.8%
Average electricity (cents per kilowatthour)	10.0	10.1	10.5	11.0	11.1	11.3	11.8	0.6%

Table A1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Prices (nominal dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	112	109	90	112	142	180	229	2.8%
West Texas Intermediate	94	98	83	105	133	171	220	3.0%
Natural gas at Henry Hub (dollars per million Btu)	2.75	3.73	5.54	6.72	7.63	9.70	12.73	4.7%
Coal (dollars per ton)								
at the minemouth[16]	40.0	37.2	43.0	49.7	58.6	68.6	79.8	2.9%
Coal (dollars per million Btu)								
at the minemouth[16]	1.98	1.84	2.14	2.48	2.92	3.41	3.96	2.9%
Average end-use[17]	2.59	2.50	2.88	3.33	3.81	4.35	5.00	2.6%
Average electricity (cents per kilowatthour)	9.8	10.1	11.9	13.5	14.8	16.6	19.2	2.4%

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2012 and 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values and 2012 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). Other 2012 petroleum supply values: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2012 and 2013 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2012 and 2013 coal values: *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2012 and 2013 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Energy consumption								
Residential								
Propane	0.40	0.43	0.32	0.30	0.28	0.26	0.25	-2.0%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00	-3.0%
Distillate fuel oil	0.49	0.50	0.40	0.35	0.31	0.27	0.24	-2.7%
Petroleum and other liquids subtotal	0.90	0.93	0.73	0.66	0.59	0.54	0.49	-2.4%
Natural gas	4.25	5.05	4.63	4.54	4.52	4.43	4.31	-0.6%
Renewable energy[1]	0.44	0.58	0.41	0.39	0.38	0.36	0.35	-1.8%
Electricity	4.69	4.75	4.86	4.92	5.08	5.23	5.42	0.5%
Delivered energy	**10.28**	**11.32**	**10.63**	**10.51**	**10.57**	**10.56**	**10.57**	**-0.3%**
Electricity related losses	9.57	9.79	9.75	9.74	9.91	10.10	10.33	0.2%
Total	**19.85**	**21.10**	**20.38**	**20.25**	**20.48**	**20.66**	**20.91**	**0.0%**
Commercial								
Propane	0.14	0.15	0.16	0.17	0.17	0.17	0.18	0.7%
Motor gasoline[2]	0.04	0.05	0.05	0.05	0.05	0.05	0.06	0.8%
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4%
Distillate fuel oil	0.36	0.37	0.34	0.32	0.30	0.29	0.27	-1.1%
Residual fuel oil	0.03	0.03	0.07	0.07	0.07	0.07	0.06	3.3%
Petroleum and other liquids subtotal	0.57	0.59	0.62	0.61	0.60	0.59	0.58	-0.1%
Natural gas	2.97	3.37	3.30	3.29	3.43	3.57	3.71	0.4%
Coal	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.5%
Renewable energy[3]	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Electricity	4.53	4.57	4.82	4.99	5.19	5.40	5.66	0.8%
Delivered energy	**8.22**	**8.69**	**8.90**	**9.06**	**9.38**	**9.73**	**10.12**	**0.6%**
Electricity related losses	9.24	9.42	9.68	9.88	10.13	10.43	10.80	0.5%
Total	**17.46**	**18.10**	**18.58**	**18.94**	**19.52**	**20.16**	**20.92**	**0.5%**
Industrial[4]								
Liquefied petroleum gases and other[5]	2.42	2.51	3.20	3.56	3.72	3.69	3.67	1.4%
Motor gasoline[2]	0.24	0.25	0.26	0.26	0.25	0.25	0.25	0.0%
Distillate fuel oil	1.28	1.31	1.42	1.38	1.36	1.34	1.35	0.1%
Residual fuel oil	0.07	0.06	0.10	0.14	0.13	0.13	0.13	2.9%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Other petroleum[6]	3.33	3.52	3.67	3.80	3.83	3.89	3.99	0.5%
Petroleum and other liquids subtotal	8.08	8.40	9.61	10.24	10.44	10.47	10.59	0.9%
Natural gas	7.39	7.62	8.33	8.47	8.65	8.76	8.90	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Natural gas subtotal	8.82	9.14	10.20	10.44	10.75	10.94	11.19	0.8%
Metallurgical coal	0.59	0.62	0.61	0.59	0.56	0.53	0.51	-0.7%
Other industrial coal	0.87	0.88	0.93	0.95	0.96	0.97	0.99	0.4%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.00	-0.02	0.00	-0.01	-0.03	-0.05	-0.06	4.5%
Coal subtotal	1.47	1.48	1.54	1.53	1.48	1.44	1.44	-0.1%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewable energy[8]	1.51	1.48	1.53	1.60	1.59	1.58	1.63	0.4%
Electricity	3.36	3.26	3.74	3.98	4.04	4.05	4.12	0.9%
Delivered energy	**23.97**	**24.48**	**27.42**	**28.58**	**29.10**	**29.29**	**29.82**	**0.7%**
Electricity related losses	6.87	6.72	7.51	7.88	7.88	7.83	7.85	0.6%
Total	**30.84**	**31.20**	**34.93**	**36.46**	**36.98**	**37.12**	**37.68**	**0.7%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Transportation								
Propane	0.05	0.05	0.04	0.05	0.05	0.06	0.07	1.3%
Motor gasoline[2]	15.82	15.94	15.35	14.22	13.30	12.82	12.55	-0.9%
of which: E85[9]	0.01	0.02	0.03	0.12	0.20	0.24	0.28	10.0%
Jet fuel[10]	2.86	2.80	3.01	3.20	3.40	3.54	3.64	1.0%
Distillate fuel oil[11]	5.80	6.50	7.35	7.59	7.76	7.94	7.97	0.8%
Residual fuel oil	0.67	0.57	0.35	0.36	0.36	0.36	0.36	-1.6%
Other petroleum[12]	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.2%
Petroleum and other liquids subtotal	25.35	26.00	26.27	25.57	25.03	24.88	24.76	-0.2%
Pipeline fuel natural gas	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Compressed / liquefied natural gas	0.04	0.05	0.07	0.10	0.17	0.31	0.71	10.3%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.04	0.04	0.05	0.06	3.4%
Delivered energy	**26.16**	**26.96**	**27.22**	**26.60**	**26.18**	**26.19**	**26.49**	**-0.1%**
Electricity related losses	0.05	0.05	0.06	0.07	0.08	0.10	0.12	3.1%
Total	**26.20**	**27.01**	**27.29**	**26.67**	**26.27**	**26.29**	**26.61**	**-0.1%**
Unspecified sector[13]	**0.04**	**-0.27**	**-0.34**	**-0.36**	**-0.37**	**-0.38**	**-0.38**	**- -**
Delivered energy consumption for all sectors								
Liquefied petroleum gases and other[5]	3.01	3.14	3.73	4.08	4.23	4.19	4.17	1.1%
Motor gasoline[2]	16.10	16.36	15.79	14.65	13.72	13.23	12.96	-0.9%
of which: E85[9]	0.01	0.02	0.03	0.12	0.20	0.24	0.28	10.0%
Jet fuel[10]	2.90	2.97	3.20	3.39	3.61	3.76	3.86	1.0%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.0%
Distillate fuel oil	7.92	8.10	8.86	8.97	9.05	9.14	9.13	0.4%
Residual fuel oil	0.77	0.65	0.53	0.56	0.56	0.55	0.56	-0.6%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Other petroleum[14]	3.47	3.67	3.82	3.96	3.98	4.05	4.15	0.5%
Petroleum and other liquids subtotal	34.93	35.65	36.89	36.72	36.30	36.09	36.03	0.0%
Natural gas	14.65	16.10	16.32	16.40	16.76	17.07	17.64	0.3%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Pipeline fuel natural gas	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Natural gas subtotal	16.82	18.50	19.05	19.28	19.80	20.19	20.88	0.4%
Metallurgical coal	0.59	0.62	0.61	0.59	0.56	0.53	0.51	-0.7%
Other coal	0.91	0.92	0.98	1.00	1.00	1.01	1.04	0.4%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.00	-0.02	0.00	-0.01	-0.03	-0.05	-0.06	4.5%
Coal subtotal	1.51	1.52	1.59	1.58	1.53	1.49	1.49	-0.1%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewable energy[15]	2.06	2.18	2.06	2.11	2.09	2.06	2.10	-0.1%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.61	12.60	13.45	13.91	14.35	14.74	15.25	0.7%
Delivered energy	**68.66**	**71.17**	**73.84**	**74.39**	**74.87**	**75.39**	**76.62**	**0.3%**
Electricity related losses	25.73	25.97	27.00	27.58	28.01	28.46	29.10	0.4%
Total	**94.40**	**97.14**	**100.84**	**101.97**	**102.87**	**103.85**	**105.73**	**0.3%**
Electric power[16]								
Distillate fuel oil	0.05	0.05	0.09	0.09	0.08	0.08	0.08	1.6%
Residual fuel oil	0.17	0.21	0.08	0.09	0.09	0.09	0.09	-3.0%
Petroleum and other liquids subtotal	0.22	0.26	0.17	0.17	0.17	0.17	0.18	-1.5%
Natural gas	9.31	8.36	7.80	8.33	9.03	9.40	9.61	0.5%
Steam coal	15.82	16.49	17.59	17.75	17.63	17.54	17.52	0.2%
Nuclear / uranium[17]	8.06	8.27	8.42	8.46	8.47	8.51	8.73	0.2%
Renewable energy[18]	4.53	4.78	6.13	6.43	6.72	7.26	7.99	1.9%
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.16	0.18	0.11	0.12	0.10	0.09	0.11	-1.8%
Total	**38.34**	**38.57**	**40.45**	**41.49**	**42.35**	**43.19**	**44.36**	**0.5%**

Table A2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Total energy consumption								
Liquefied petroleum gases and other[5]	3.01	3.14	3.73	4.08	4.23	4.19	4.17	1.1%
Motor gasoline[2]	16.10	16.36	15.79	14.65	13.72	13.23	12.96	-0.9%
of which: E85[9]	0.01	0.02	0.03	0.12	0.20	0.24	0.28	10.0%
Jet fuel[10]	2.90	2.97	3.20	3.39	3.61	3.76	3.86	1.0%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.0%
Distillate fuel oil	7.98	8.15	8.95	9.06	9.13	9.22	9.21	0.5%
Residual fuel oil	0.94	0.87	0.61	0.65	0.64	0.64	0.65	-1.1%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Other petroleum[14]	3.47	3.67	3.82	3.96	3.98	4.05	4.15	0.5%
Petroleum and other liquids subtotal	35.16	35.91	37.06	36.89	36.47	36.26	36.21	0.0%
Natural gas	23.96	24.46	24.12	24.73	25.79	26.47	27.25	0.4%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Pipeline fuel natural gas	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Natural gas subtotal	26.14	26.86	26.85	27.60	28.83	29.59	30.50	0.5%
Metallurgical coal	0.59	0.62	0.61	0.59	0.56	0.53	0.51	-0.7%
Other coal	16.73	17.41	18.57	18.75	18.63	18.55	18.56	0.2%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.00	-0.02	0.00	-0.01	-0.03	-0.05	-0.06	4.5%
Coal subtotal	17.33	18.01	19.18	19.33	19.16	19.03	19.01	0.2%
Nuclear / uranium[17]	8.06	8.27	8.42	8.46	8.47	8.51	8.73	0.2%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewable energy[19]	6.59	6.96	8.19	8.54	8.81	9.32	10.09	1.4%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.16	0.18	0.11	0.12	0.10	0.09	0.11	-1.8%
Total	**94.40**	**97.14**	**100.84**	**101.97**	**102.87**	**103.85**	**105.73**	**0.3%**
Energy use and related statistics								
Delivered energy use	68.66	71.17	73.84	74.39	74.87	75.39	76.62	0.3%
Total energy use	94.40	97.14	100.84	101.97	102.87	103.85	105.73	0.3%
Ethanol consumed in motor gasoline and E85	1.09	1.12	1.12	1.12	1.12	1.16	1.27	0.5%
Population (millions)	315	317	334	347	359	370	380	0.7%
Gross domestic product (billion 2009 dollars)	15,369	15,710	18,801	21,295	23,894	26,659	29,898	2.4%
Carbon dioxide emissions (million metric tons)	5,272	5,405	5,499	5,511	5,514	5,521	5,549	0.1%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2012 and 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014).
Projections: EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A3. Energy prices by sector and source
(2013 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Propane	24.3	23.3	23.0	23.7	24.4	25.5	26.6	0.5%
Distillate fuel oil	27.3	27.2	21.5	23.7	26.3	29.4	32.9	0.7%
Natural gas	10.6	10.0	11.6	12.7	12.8	13.7	15.5	1.6%
Electricity	35.3	35.6	37.8	39.6	40.0	40.8	42.4	0.6%
Commercial								
Propane	21.0	20.0	19.4	20.2	21.1	22.5	23.9	0.7%
Distillate fuel oil	26.8	26.7	21.0	23.2	25.8	28.9	32.5	0.7%
Residual fuel oil	22.9	22.1	14.2	16.0	18.1	20.6	24.3	0.4%
Natural gas	8.2	8.1	9.6	10.5	10.4	11.1	12.6	1.6%
Electricity	30.0	29.7	31.1	32.5	32.6	33.1	34.5	0.6%
Industrial[1]								
Propane	21.3	20.3	19.6	20.5	21.5	22.9	24.5	0.7%
Distillate fuel oil	27.4	27.3	21.2	23.5	26.1	29.2	32.7	0.7%
Residual fuel oil	20.6	20.0	13.3	15.1	17.2	19.7	23.5	0.6%
Natural gas[2]	3.8	4.6	6.2	6.9	6.8	7.5	8.8	2.5%
Metallurgical coal	7.3	5.5	5.8	6.2	6.7	6.9	7.2	1.0%
Other industrial coal	3.3	3.2	3.3	3.5	3.6	3.7	3.9	0.7%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.8	20.2	21.3	22.4	22.6	23.3	24.7	0.7%
Transportation								
Propane	25.3	24.6	24.0	24.7	25.5	26.5	27.6	0.4%
E85[3]	35.7	33.1	30.4	29.0	31.2	33.2	35.4	0.3%
Motor gasoline[4]	30.7	29.3	22.5	24.3	26.4	29.1	32.3	0.4%
Jet fuel[5]	23.0	21.8	16.1	18.3	21.3	24.5	28.3	1.0%
Diesel fuel (distillate fuel oil)[6]	28.8	28.2	23.1	25.5	28.0	31.1	34.7	0.8%
Residual fuel oil	20.0	19.3	11.7	13.3	15.4	17.6	20.3	0.2%
Natural gas[7]	20.4	17.6	17.8	16.8	15.7	17.1	19.6	0.4%
Electricity	27.8	28.5	30.2	32.3	32.9	33.9	36.0	0.9%
Electric power[8]								
Distillate fuel oil	24.1	24.0	18.8	20.9	23.6	26.7	30.2	0.9%
Residual fuel oil	20.8	18.9	11.5	13.3	15.4	17.8	21.6	0.5%
Natural gas	3.5	4.4	5.4	6.3	6.2	7.0	8.3	2.4%
Steam coal	2.4	2.3	2.4	2.5	2.7	2.8	2.9	0.8%
Average price to all users[9]								
Propane	22.9	21.9	21.1	21.8	22.6	23.8	25.2	0.5%
E85[3]	35.7	33.1	30.4	29.0	31.2	33.2	35.4	0.3%
Motor gasoline[4]	30.4	29.0	22.5	24.3	26.4	29.1	32.3	0.4%
Jet fuel[5]	23.0	21.8	16.1	18.3	21.3	24.5	28.3	1.0%
Distillate fuel oil	28.3	27.9	22.6	25.0	27.6	30.7	34.2	0.8%
Residual fuel oil	20.3	19.4	12.2	14.0	16.0	18.4	21.5	0.4%
Natural gas	5.5	6.1	7.5	8.3	8.2	9.0	10.5	2.0%
Metallurgical coal	7.3	5.5	5.8	6.2	6.7	6.9	7.2	1.0%
Other coal	2.5	2.4	2.4	2.6	2.7	2.8	3.0	0.8%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	29.3	29.5	30.8	32.1	32.4	33.2	34.7	0.6%
Non-renewable energy expenditures by sector (billion 2013 dollars)								
Residential	234	243	254	268	276	289	311	0.9%
Commercial	174	177	194	210	219	234	259	1.4%
Industrial[1]	218	224	264	302	323	349	389	2.1%
Transportation	738	719	565	596	638	706	791	0.4%
Total non-renewable expenditures	1,364	1,364	1,276	1,376	1,456	1,579	1,751	0.9%
Transportation renewable expenditures	0	1	1	4	6	8	10	10.2%
Total expenditures	**1,365**	**1,364**	**1,277**	**1,379**	**1,462**	**1,587**	**1,761**	**0.9%**

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Propane	23.9	23.3	26.1	29.1	32.8	37.5	43.1	2.3%
Distillate fuel oil	26.9	27.2	24.4	29.1	35.3	43.2	53.3	2.5%
Natural gas	10.4	10.0	13.2	15.7	17.1	20.2	25.1	3.5%
Electricity	34.8	35.6	42.9	48.8	53.6	60.0	68.8	2.5%
Commercial								
Propane	20.7	20.0	22.0	24.9	28.3	33.0	38.8	2.5%
Distillate fuel oil	26.4	26.7	23.8	28.6	34.6	42.5	52.6	2.5%
Residual fuel oil	22.6	22.1	16.1	19.7	24.3	30.3	39.4	2.2%
Natural gas	8.0	8.1	10.8	13.0	13.9	16.4	20.5	3.5%
Electricity	29.6	29.7	35.3	40.0	43.7	48.7	56.0	2.4%
Industrial[1]								
Propane	21.0	20.3	22.3	25.2	28.8	33.7	39.7	2.5%
Distillate fuel oil	27.0	27.3	24.1	29.0	35.0	42.9	53.0	2.5%
Residual fuel oil	20.3	20.0	15.1	18.6	23.1	29.0	38.0	2.4%
Natural gas[2]	3.8	4.6	7.0	8.5	9.1	11.1	14.2	4.3%
Metallurgical coal	7.2	5.5	6.6	7.7	8.9	10.2	11.6	2.8%
Other industrial coal	3.3	3.2	3.8	4.3	4.8	5.5	6.3	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.5	20.2	24.2	27.5	30.3	34.2	40.0	2.6%
Transportation								
Propane	24.9	24.6	27.2	30.4	34.1	38.9	44.8	2.2%
E85[3]	35.2	33.1	34.4	35.8	41.9	48.8	57.4	2.1%
Motor gasoline[4]	30.2	29.3	25.5	29.9	35.3	42.8	52.4	2.2%
Jet fuel[5]	22.6	21.8	18.3	22.6	28.6	36.0	45.8	2.8%
Diesel fuel (distillate fuel oil)[6]	28.4	28.2	26.2	31.4	37.6	45.7	56.2	2.6%
Residual fuel oil	19.7	19.3	13.2	16.4	20.6	25.9	32.9	2.0%
Natural gas[7]	20.1	17.6	20.2	20.6	21.0	25.2	31.8	2.2%
Electricity	27.4	28.5	34.3	39.8	44.1	49.9	58.4	2.7%
Electric power[8]								
Distillate fuel oil	23.8	24.0	21.3	25.8	31.7	39.3	49.0	2.7%
Residual fuel oil	20.5	18.9	13.0	16.3	20.6	26.2	35.0	2.3%
Natural gas	3.5	4.4	6.1	7.7	8.3	10.3	13.4	4.2%
Steam coal	2.4	2.3	2.7	3.1	3.6	4.1	4.7	2.6%

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Average price to all users[9]								
Propane	22.6	21.9	23.9	26.8	30.3	35.0	40.9	2.3%
E85[3]	35.2	33.1	34.4	35.8	41.9	48.8	57.4	2.1%
Motor gasoline[4]	30.0	29.0	25.5	29.9	35.3	42.8	52.4	2.2%
Jet fuel[5]	22.6	21.8	18.3	22.6	28.6	36.0	45.8	2.8%
Distillate fuel oil	27.9	27.9	25.7	30.8	36.9	45.1	55.5	2.6%
Residual fuel oil	20.0	19.4	13.8	17.2	21.5	27.0	34.8	2.2%
Natural gas	5.4	6.1	8.5	10.2	11.0	13.2	17.0	3.8%
Metallurgical coal	7.2	5.5	6.6	7.7	8.9	10.2	11.6	2.8%
Other coal	2.4	2.4	2.8	3.2	3.7	4.2	4.8	2.6%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	28.8	29.5	34.9	39.5	43.4	48.7	56.2	2.4%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	231	243	288	330	370	425	504	2.7%
Commercial	172	177	220	259	294	344	420	3.2%
Industrial[1]	215	224	299	372	433	513	631	3.9%
Transportation	727	719	641	734	855	1,038	1,283	2.2%
Total non-renewable expenditures	1,344	1,364	1,448	1,694	1,952	2,320	2,839	2.8%
Transportation renewable expenditures	0	1	1	4	8	12	16	12.2%
Total expenditures	**1,345**	**1,364**	**1,449**	**1,698**	**1,960**	**2,332**	**2,855**	**2.8%**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2012 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014), EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014) and estimated State and Federal motor fuel taxes and dispensing costs or charges. 2013 transportation sector natural gas delivered prices are model results. 2012 and 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2012 and 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2012 and 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Key indicators								
Households (millions)								
Single-family	79.3	79.7	84.5	88.4	92.1	95.4	98.6	0.8%
Multifamily	28.2	28.4	30.4	32.1	33.9	35.7	37.5	1.0%
Mobile homes	6.4	6.3	5.5	5.3	5.1	4.9	4.8	-1.0%
Total	**113.9**	**114.3**	**120.5**	**125.8**	**131.1**	**136.0**	**141.0**	**0.8%**
Average house square footage	**1,670**	**1,678**	**1,733**	**1,768**	**1,800**	**1,829**	**1,855**	**0.4%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	90.2	99.0	88.2	83.5	80.6	77.6	75.0	-1.0%
Total energy consumption	174.3	184.6	169.1	161.0	156.2	151.9	148.3	-0.8%
(thousand Btu per square foot)								
Delivered energy consumption	54.0	59.0	50.9	47.3	44.8	42.5	40.4	-1.4%
Total energy consumption	104.3	110.0	97.6	91.1	86.8	83.1	79.9	-1.2%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating	0.29	0.40	0.35	0.34	0.33	0.32	0.31	-1.0%
Space cooling	0.83	0.66	0.79	0.82	0.88	0.94	1.00	1.5%
Water heating	0.44	0.44	0.46	0.47	0.48	0.48	0.48	0.2%
Refrigeration	0.37	0.36	0.34	0.33	0.33	0.35	0.36	0.0%
Cooking	0.11	0.11	0.11	0.12	0.13	0.14	0.14	1.1%
Clothes dryers	0.20	0.20	0.21	0.22	0.23	0.24	0.25	0.7%
Freezers	0.08	0.08	0.07	0.07	0.07	0.06	0.06	-0.7%
Lighting	0.64	0.59	0.43	0.38	0.34	0.29	0.27	-2.9%
Clothes washers[1]	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-2.0%
Dishwashers[1]	0.10	0.09	0.10	0.10	0.11	0.12	0.12	1.0%
Televisions and related equipment[2]	0.33	0.33	0.32	0.32	0.34	0.36	0.37	0.5%
Computers and related equipment[3]	0.12	0.12	0.10	0.08	0.07	0.06	0.05	-3.1%
Furnace fans and boiler circulation pumps	0.09	0.13	0.11	0.11	0.10	0.10	0.09	-1.3%
Other uses[4]	1.06	1.19	1.44	1.53	1.65	1.77	1.89	1.7%
Delivered energy	**4.69**	**4.75**	**4.86**	**4.92**	**5.08**	**5.23**	**5.42**	**0.5%**
Natural gas								
Space heating	2.52	3.32	2.90	2.80	2.76	2.69	2.61	-0.9%
Space cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.2%
Water heating	1.20	1.20	1.21	1.22	1.24	1.23	1.19	0.0%
Cooking	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.3%
Clothes dryers	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.5%
Other uses[5]	0.25	0.25	0.24	0.23	0.23	0.22	0.21	-0.6%
Delivered energy	**4.25**	**5.05**	**4.63**	**4.54**	**4.52**	**4.43**	**4.31**	**-0.6%**
Distillate fuel oil								
Space heating	0.43	0.44	0.36	0.32	0.28	0.25	0.22	-2.5%
Water heating	0.05	0.05	0.03	0.03	0.02	0.02	0.01	-4.7%
Other uses[6]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.5%
Delivered energy	**0.49**	**0.50**	**0.40**	**0.35**	**0.31**	**0.27**	**0.24**	**-2.7%**
Propane								
Space heating	0.26	0.30	0.20	0.18	0.17	0.15	0.14	-2.8%
Water heating	0.07	0.06	0.05	0.04	0.04	0.03	0.03	-3.0%
Cooking	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-0.9%
Other uses[6]	0.04	0.04	0.05	0.05	0.05	0.06	0.06	1.5%
Delivered energy	**0.40**	**0.43**	**0.32**	**0.30**	**0.28**	**0.26**	**0.25**	**-2.0%**
Marketed renewables (wood)[7]	0.44	0.58	0.41	0.39	0.38	0.36	0.35	-1.8%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00	-3.0%

Table A4. Residential sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Delivered energy consumption by end use								
Space heating	3.95	5.05	4.23	4.04	3.92	3.78	3.63	-1.2%
Space cooling	0.86	0.68	0.81	0.84	0.90	0.96	1.02	1.5%
Water heating	1.76	1.76	1.75	1.76	1.78	1.75	1.71	-0.1%
Refrigeration	0.37	0.36	0.34	0.33	0.33	0.35	0.36	0.0%
Cooking	0.35	0.34	0.35	0.36	0.37	0.38	0.39	0.4%
Clothes dryers	0.25	0.25	0.26	0.27	0.28	0.29	0.30	0.7%
Freezers	0.08	0.08	0.07	0.07	0.07	0.06	0.06	-0.7%
Lighting	0.64	0.59	0.43	0.38	0.34	0.29	0.27	-2.9%
Clothes washers[1]	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-2.0%
Dishwashers[1]	0.10	0.09	0.10	0.10	0.11	0.12	0.12	1.0%
Televisions and related equipment[2]	0.33	0.33	0.32	0.32	0.34	0.36	0.37	0.5%
Computers and related equipment[3]	0.12	0.12	0.10	0.08	0.07	0.06	0.05	-3.1%
Furnace fans and boiler circulation pumps	0.09	0.13	0.11	0.11	0.10	0.10	0.09	-1.3%
Other uses[8]	1.36	1.49	1.73	1.82	1.94	2.05	2.17	1.4%
Delivered energy	**10.28**	**11.32**	**10.63**	**10.51**	**10.57**	**10.56**	**10.57**	**-0.3%**
Electricity related losses	**9.57**	**9.79**	**9.75**	**9.74**	**9.91**	**10.10**	**10.33**	**0.2%**
Total energy consumption by end use								
Space heating	4.53	5.88	4.93	4.71	4.56	4.39	4.21	-1.2%
Space cooling	2.56	2.05	2.38	2.47	2.62	2.79	2.93	1.3%
Water heating	2.66	2.68	2.69	2.70	2.72	2.68	2.62	-0.1%
Refrigeration	1.12	1.12	1.02	0.99	0.99	1.01	1.06	-0.2%
Cooking	0.56	0.56	0.58	0.60	0.62	0.64	0.66	0.6%
Clothes dryers	0.66	0.67	0.69	0.70	0.73	0.75	0.78	0.5%
Freezers	0.24	0.24	0.22	0.20	0.19	0.19	0.19	-0.9%
Lighting	1.94	1.80	1.29	1.13	1.00	0.85	0.77	-3.1%
Clothes washers[1]	0.09	0.09	0.07	0.05	0.05	0.05	0.05	-2.2%
Dishwashers[1]	0.29	0.29	0.29	0.30	0.32	0.34	0.36	0.8%
Televisions and related equipment[2]	1.01	1.01	0.97	0.96	1.00	1.05	1.09	0.3%
Computers and related equipment[3]	0.38	0.37	0.29	0.24	0.20	0.18	0.15	-3.3%
Furnace fans and boiler circulation pumps	0.28	0.40	0.34	0.33	0.31	0.28	0.27	-1.5%
Other uses[8]	3.52	3.95	4.62	4.86	5.17	5.46	5.78	1.4%
Total	**19.85**	**21.10**	**20.38**	**20.25**	**20.48**	**20.66**	**20.91**	**0.0%**
Nonmarketed renewables[9]								
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.03	0.03	0.03	4.1%
Solar hot water heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.8%
Solar photovoltaic	0.02	0.04	0.09	0.13	0.18	0.24	0.29	8.0%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	6.9%
Total	**0.04**	**0.06**	**0.13**	**0.17**	**0.23**	**0.28**	**0.35**	**7.0%**
Heating degree days[10]	**3,772**	**4,469**	**4,119**	**4,042**	**3,966**	**3,893**	**3,820**	**-0.6%**
Cooling degree days[10]	**1,494**	**1,307**	**1,467**	**1,517**	**1,568**	**1,618**	**1,670**	**0.9%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Includes such appliances as outdoor grills, exterior lights, pool heaters, spa heaters, and backup electricity generators.
[6]Includes such appliances as pool heaters, spa heaters, and backup electricity generators.
[7]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2009*.
[8]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[9]Consumption determined by using the fossil fuel equivalent of 9,516 Btu per kilowatthour.
[10]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Key indicators								
Total floorspace (billion square feet)								
Surviving	80.8	81.4	86.9	92.0	96.4	100.9	106.6	1.0%
New additions	1.6	1.5	2.1	2.0	2.0	2.3	2.4	1.9%
Total	**82.3**	**82.8**	**89.0**	**94.1**	**98.4**	**103.2**	**109.1**	**1.0%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	99.8	104.9	100.0	96.3	95.4	94.2	92.8	-0.5%
Electricity related losses	112.3	113.7	108.7	105.1	103.0	101.1	99.0	-0.5%
Total energy consumption	212.1	218.6	208.7	201.4	198.4	195.3	191.8	-0.5%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.14	0.16	0.14	0.13	0.12	0.11	0.11	-1.5%
Space cooling[1]	0.57	0.49	0.53	0.53	0.54	0.55	0.56	0.5%
Water heating[1]	0.09	0.09	0.09	0.09	0.08	0.08	0.08	-0.6%
Ventilation	0.51	0.52	0.54	0.55	0.56	0.57	0.58	0.4%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Lighting	0.92	0.91	0.87	0.85	0.84	0.81	0.80	-0.5%
Refrigeration	0.38	0.37	0.33	0.31	0.30	0.31	0.31	-0.7%
Office equipment (PC)	0.12	0.11	0.07	0.05	0.04	0.03	0.02	-5.5%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.34	0.38	2.1%
Other uses[2]	1.56	1.68	1.99	2.19	2.38	2.58	2.80	1.9%
Delivered energy	**4.53**	**4.57**	**4.82**	**4.99**	**5.19**	**5.40**	**5.66**	**0.8%**
Natural gas								
Space heating[1]	1.51	1.86	1.69	1.62	1.58	1.51	1.41	-1.0%
Space cooling[1]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.1%
Water heating[1]	0.53	0.54	0.54	0.55	0.57	0.57	0.57	0.2%
Cooking	0.20	0.20	0.21	0.22	0.23	0.24	0.25	0.8%
Other uses[3]	0.69	0.74	0.81	0.87	1.01	1.21	1.44	2.5%
Delivered energy	**2.97**	**3.37**	**3.30**	**3.29**	**3.43**	**3.57**	**3.71**	**0.4%**
Distillate fuel oil								
Space heating[1]	0.13	0.15	0.14	0.13	0.12	0.11	0.10	-1.7%
Water heating[1]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.1%
Other uses[4]	0.21	0.20	0.18	0.17	0.17	0.16	0.16	-0.8%
Delivered energy	**0.36**	**0.37**	**0.34**	**0.32**	**0.30**	**0.29**	**0.27**	**-1.1%**
Marketed renewables (biomass)	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Other fuels[5]	0.26	0.26	0.33	0.34	0.34	0.35	0.35	1.1%
Delivered energy consumption by end use								
Space heating[1]	1.78	2.17	1.97	1.87	1.82	1.73	1.61	-1.1%
Space cooling[1]	0.62	0.53	0.57	0.57	0.57	0.58	0.59	0.4%
Water heating[1]	0.64	0.65	0.65	0.65	0.67	0.67	0.67	0.1%
Ventilation	0.51	0.52	0.54	0.55	0.56	0.57	0.58	0.4%
Cooking	0.22	0.22	0.24	0.24	0.25	0.26	0.27	0.7%
Lighting	0.92	0.91	0.87	0.85	0.84	0.81	0.80	-0.5%
Refrigeration	0.38	0.37	0.33	0.31	0.30	0.31	0.31	-0.7%
Office equipment (PC)	0.12	0.11	0.07	0.05	0.04	0.03	0.02	-5.5%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.34	0.38	2.1%
Other uses[6]	2.82	3.00	3.43	3.69	4.02	4.42	4.87	1.8%
Delivered energy	**8.22**	**8.69**	**8.90**	**9.06**	**9.38**	**9.73**	**10.12**	**0.6%**

Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Electricity related losses	**9.24**	**9.42**	**9.68**	**9.88**	**10.13**	**10.43**	**10.80**	**0.5%**
Total energy consumption by end use								
Space heating[1]	2.05	2.50	2.25	2.13	2.05	1.95	1.82	-1.2%
Space cooling[1]	1.78	1.54	1.63	1.62	1.62	1.64	1.66	0.3%
Water heating[1]	0.83	0.84	0.83	0.82	0.83	0.83	0.82	-0.1%
Ventilation	1.55	1.58	1.63	1.64	1.66	1.67	1.68	0.2%
Cooking	0.27	0.27	0.28	0.28	0.30	0.31	0.31	0.5%
Lighting	2.81	2.78	2.62	2.53	2.47	2.38	2.34	-0.6%
Refrigeration	1.15	1.14	0.99	0.93	0.90	0.90	0.91	-0.8%
Office equipment (PC)	0.35	0.33	0.20	0.15	0.11	0.09	0.07	-5.7%
Office equipment (non-PC)	0.66	0.66	0.72	0.81	0.91	1.01	1.10	1.9%
Other uses[6]	6.01	6.47	7.43	8.02	8.67	9.40	10.21	1.7%
Total	**17.46**	**18.10**	**18.58**	**18.94**	**19.52**	**20.16**	**20.92**	**0.5%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.08	0.08	0.09	0.09	0.10	0.10	0.11	1.1%
Solar photovoltaic	0.04	0.05	0.08	0.11	0.15	0.20	0.27	6.1%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	9.0%
Total	**0.13**	**0.14**	**0.17**	**0.20**	**0.25**	**0.32**	**0.39**	**3.9%**
Heating degree days								
New England	5,561	6,424	6,030	5,924	5,818	5,711	5,603	-0.5%
Middle Atlantic	4,970	5,836	5,427	5,333	5,239	5,146	5,054	-0.5%
East North Central	5,356	6,622	6,016	5,953	5,890	5,827	5,764	-0.5%
West North Central	5,515	7,134	6,367	6,322	6,275	6,229	6,181	-0.5%
South Atlantic	2,307	2,732	2,595	2,552	2,508	2,466	2,425	-0.4%
East South Central	2,876	3,649	3,349	3,325	3,301	3,276	3,251	-0.4%
West South Central	1,650	2,328	1,975	1,928	1,882	1,836	1,790	-1.0%
Mountain	4,574	5,271	4,874	4,809	4,741	4,669	4,595	-0.5%
Pacific	3,412	3,377	3,477	3,463	3,450	3,438	3,426	0.1%
United States	**3,772**	**4,469**	**4,119**	**4,042**	**3,966**	**3,893**	**3,820**	**-0.6%**
Cooling degree days								
New England	564	541	573	603	634	664	695	0.9%
Middle Atlantic	815	688	803	840	877	913	950	1.2%
East North Central	974	690	821	841	860	880	900	1.0%
West North Central	1,221	893	1,012	1,031	1,051	1,070	1,090	0.7%
South Atlantic	2,161	2,002	2,191	2,235	2,280	2,325	2,369	0.6%
East South Central	1,762	1,441	1,725	1,756	1,787	1,818	1,849	0.9%
West South Central	2,915	2,535	2,848	2,920	2,993	3,065	3,138	0.8%
Mountain	1,572	1,464	1,556	1,607	1,660	1,715	1,772	0.7%
Pacific	917	889	891	915	940	963	987	0.4%
United States	**1,494**	**1,307**	**1,467**	**1,517**	**1,568**	**1,618**	**1,670**	**0.9%**

[1]Includes fuel consumption for district services.
[2]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, and water services.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, propane, coal, motor gasoline, and kerosene.
[6]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[7]Consumption determined by using the fossil fuel equivalent of 9,516 Btu per kilowatthour.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A6. Industrial sector key indicators and consumption

Shipments, prices, and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Key indicators								
Value of shipments (billion 2009 dollars)								
Manufacturing	5,009	5,146	6,123	6,771	7,330	8,012	8,751	2.0%
Agriculture, mining, and construction	1,813	1,858	2,344	2,441	2,540	2,601	2,712	1.4%
Total	**6,822**	**7,004**	**8,467**	**9,212**	**9,870**	**10,614**	**11,463**	**1.8%**
Energy prices								
(2013 dollars per million Btu)								
Propane	21.3	20.3	19.6	20.5	21.5	22.9	24.5	0.7%
Motor gasoline	17.5	17.5	22.5	24.2	26.3	29.1	32.3	2.3%
Distillate fuel oil	27.4	27.3	21.2	23.5	26.1	29.2	32.7	0.7%
Residual fuel oil	20.6	20.0	13.3	15.1	17.2	19.7	23.5	0.6%
Asphalt and road oil	10.1	9.8	8.9	10.3	11.9	13.5	15.7	1.8%
Natural gas heat and power	3.5	4.3	6.0	6.7	6.6	7.4	8.6	2.6%
Natural gas feedstocks	4.2	4.8	6.3	7.0	6.9	7.7	8.9	2.3%
Metallurgical coal	7.3	5.5	5.8	6.2	6.7	6.9	7.2	1.0%
Other industrial coal	3.3	3.2	3.3	3.5	3.6	3.7	3.9	0.7%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.8	20.2	21.3	22.4	22.6	23.3	24.7	0.7%
(nominal dollars per million Btu)								
Propane	21.0	20.3	22.3	25.2	28.8	33.7	39.7	2.5%
Motor gasoline	17.3	17.5	25.5	29.9	35.3	42.7	52.3	4.1%
Distillate fuel oil	27.0	27.3	24.1	29.0	35.0	42.9	53.0	2.5%
Residual fuel oil	20.3	20.0	15.1	18.6	23.1	29.0	38.0	2.4%
Asphalt and road oil	10.0	9.8	10.0	12.7	15.9	19.9	25.5	3.6%
Natural gas heat and power	3.5	4.3	6.8	8.2	8.9	10.8	13.9	4.4%
Natural gas feedstocks	4.1	4.8	7.2	8.6	9.3	11.3	14.5	4.2%
Metallurgical coal	7.2	5.5	6.6	7.7	8.9	10.2	11.6	2.8%
Other industrial coal	3.3	3.2	3.8	4.3	4.8	5.5	6.3	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.5	20.2	24.2	27.5	30.3	34.2	40.0	2.6%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Propane heat and power	0.25	0.28	0.32	0.36	0.38	0.38	0.38	1.1%
Liquefied petroleum gas and other feedstocks[2]	2.16	2.22	2.89	3.21	3.35	3.31	3.30	1.5%
Motor gasoline	0.24	0.25	0.26	0.26	0.25	0.25	0.25	0.0%
Distillate fuel oil	1.28	1.31	1.42	1.38	1.36	1.34	1.35	0.1%
Residual fuel oil	0.07	0.06	0.10	0.14	0.13	0.13	0.13	3.1%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Petroleum coke	0.17	0.11	0.20	0.23	0.22	0.21	0.22	2.5%
Asphalt and road oil	0.83	0.78	1.01	1.09	1.15	1.19	1.25	1.8%
Miscellaneous petroleum[3]	0.37	0.61	0.42	0.42	0.44	0.46	0.47	-1.0%
Petroleum and other liquids subtotal	6.11	6.37	7.57	8.18	8.42	8.43	8.55	1.1%
Natural gas heat and power	5.26	5.42	5.86	5.93	6.07	6.13	6.20	0.5%
Natural gas feedstocks	0.58	0.59	0.97	1.05	1.05	1.04	1.03	2.1%
Lease and plant fuel[4]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Natural gas subtotal	7.27	7.54	8.70	8.96	9.22	9.35	9.53	0.9%
Metallurgical coal and coke[5]	0.60	0.60	0.61	0.58	0.53	0.48	0.45	-1.0%
Other industrial coal	0.87	0.88	0.93	0.95	0.96	0.97	0.99	0.4%
Coal subtotal	1.47	1.48	1.54	1.53	1.48	1.44	1.44	-0.1%
Renewables[6]	1.51	1.48	1.53	1.60	1.59	1.58	1.63	0.4%
Purchased electricity	3.16	3.05	3.58	3.83	3.89	3.90	3.95	1.0%
Delivered energy	**19.52**	**19.92**	**22.92**	**24.10**	**24.60**	**24.70**	**25.10**	**0.9%**
Electricity related losses	6.46	6.29	7.19	7.59	7.59	7.52	7.54	0.7%
Total	**25.98**	**26.22**	**30.11**	**31.69**	**32.19**	**32.22**	**32.64**	**0.8%**

Table A6. Industrial sector key indicators and consumption (continued)

Shipments, prices, and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Refining consumption								
Liquefied petroleum gas heat and power[2]	0.01	0.00	0.00	0.00	0.00	0.00	0.00	- -
Distillate fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.54	0.53	0.39	0.42	0.41	0.42	0.43	-0.8%
Still gas	1.41	1.47	1.61	1.63	1.59	1.61	1.60	0.3%
Miscellaneous petroleum[3]	0.01	0.01	0.03	0.01	0.02	0.01	0.02	2.1%
Petroleum and other liquids subtotal	1.97	2.03	2.04	2.06	2.02	2.03	2.04	0.0%
Natural gas heat and power	1.23	1.30	1.19	1.17	1.20	1.25	1.31	0.0%
Natural gas feedstocks	0.32	0.31	0.31	0.31	0.32	0.34	0.35	0.5%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas subtotal	1.55	1.60	1.50	1.48	1.52	1.59	1.66	0.1%
Other industrial coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Purchased electricity	0.20	0.21	0.16	0.15	0.15	0.16	0.16	-0.8%
Delivered energy	**4.45**	**4.56**	**4.50**	**4.48**	**4.49**	**4.59**	**4.73**	**0.1%**
Electricity related losses	0.41	0.42	0.31	0.29	0.29	0.30	0.31	-1.1%
Total	**4.86**	**4.98**	**4.81**	**4.78**	**4.78**	**4.90**	**5.04**	**0.0%**
Total industrial sector consumption								
Liquefied petroleum gas heat and power[2]	0.26	0.29	0.32	0.36	0.38	0.38	0.38	1.0%
Liquefied petroleum gas and other feedstocks[2]	2.16	2.22	2.89	3.21	3.35	3.31	3.30	1.5%
Motor gasoline	0.24	0.25	0.26	0.26	0.25	0.25	0.25	0.0%
Distillate fuel oil	1.28	1.31	1.42	1.38	1.36	1.34	1.35	0.1%
Residual fuel oil	0.07	0.06	0.10	0.14	0.13	0.13	0.13	2.9%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Petroleum coke	0.70	0.65	0.59	0.65	0.63	0.63	0.65	0.0%
Asphalt and road oil	0.83	0.78	1.01	1.09	1.15	1.19	1.25	1.8%
Still gas	1.41	1.47	1.61	1.63	1.59	1.61	1.60	0.3%
Miscellaneous petroleum[3]	0.38	0.63	0.46	0.43	0.46	0.47	0.49	-0.9%
Petroleum and other liquids subtotal	8.08	8.40	9.61	10.24	10.44	10.47	10.59	0.9%
Natural gas heat and power	6.50	6.72	7.05	7.11	7.27	7.38	7.51	0.4%
Natural gas feedstocks	0.89	0.90	1.28	1.36	1.37	1.38	1.39	1.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[4]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Natural gas subtotal	8.82	9.14	10.20	10.44	10.75	10.94	11.19	0.8%
Metallurgical coal and coke[5]	0.60	0.60	0.61	0.58	0.53	0.48	0.45	-1.0%
Other industrial coal	0.87	0.88	0.93	0.95	0.96	0.97	0.99	0.4%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	1.47	1.48	1.54	1.53	1.48	1.44	1.44	-0.1%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewables[6]	1.51	1.48	1.53	1.60	1.59	1.58	1.63	0.4%
Purchased electricity	3.36	3.26	3.74	3.98	4.04	4.05	4.12	0.9%
Delivered energy	**23.97**	**24.48**	**27.42**	**28.58**	**29.10**	**29.29**	**29.82**	**0.7%**
Electricity related losses	6.87	6.72	7.51	7.88	7.88	7.83	7.85	0.6%
Total	**30.84**	**31.20**	**34.93**	**36.46**	**36.98**	**37.12**	**37.68**	**0.7%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Energy consumption per dollar of shipments (thousand Btu per 2009 dollar)								
Petroleum and other liquids	1.18	1.20	1.13	1.11	1.06	0.99	0.92	-1.0%
Natural gas	1.29	1.31	1.21	1.13	1.09	1.03	0.98	-1.1%
Coal	0.21	0.21	0.18	0.17	0.15	0.14	0.13	-1.9%
Renewable fuels[5]	0.33	0.31	0.28	0.26	0.24	0.23	0.22	-1.4%
Purchased electricity	0.49	0.47	0.44	0.43	0.41	0.38	0.36	-1.0%
Delivered energy	**3.51**	**3.50**	**3.24**	**3.10**	**2.95**	**2.76**	**2.60**	**-1.1%**
Industrial combined heat and power[1]								
Capacity (gigawatts)	26.9	27.6	30.6	32.8	35.8	38.9	40.7	1.5%
Generation (billion kilowatthours)	144	147	170	181	195	211	221	1.5%

[1]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes lubricants and miscellaneous petroleum products.
[4]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[5]Includes net coal coke imports.
[6]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 and 2013 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2012 and 2013 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2012 and 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 natural gas prices: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 natural gas prices: *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2012 refining consumption values are based on: *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2013 refining consumption based on: *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). Other 2012 and 2013 consumption values are based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 shipments: IHS Economics, Industry model, November 2014. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2,578	2,644	2,917	3,090	3,287	3,458	3,570	1.1%
Commercial light trucks[1]	62	67	79	85	92	98	105	1.7%
Freight trucks greater than 10,000 pounds	242	268	314	337	355	374	397	1.5%
(billion seat miles available)								
Air	1,033	1,047	1,174	1,279	1,391	1,481	1,557	1.5%
(billion ton miles traveled)								
Rail	1,729	1,758	1,828	1,960	1,999	2,013	2,066	0.6%
Domestic shipping	475	480	467	444	424	416	420	-0.5%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	29.4	30.0	36.3	46.0	46.3	46.5	46.8	1.7%
New car[2]	33.4	34.1	43.7	54.3	54.3	54.3	54.4	1.7%
New light truck[2]	25.7	26.3	30.9	39.5	39.5	39.5	39.5	1.5%
Compliance new light-duty vehicle[3]	32.7	32.8	37.9	46.7	47.4	47.9	48.1	1.4%
New car[3]	37.0	37.2	44.2	54.6	55.3	55.5	55.5	1.5%
New light truck[3]	28.6	28.8	33.1	40.3	40.7	40.9	40.9	1.3%
Tested new light-duty vehicle[4]	31.7	31.7	37.9	46.6	47.4	47.8	48.1	1.6%
New car[4]	36.3	36.5	44.1	54.6	55.3	55.4	55.5	1.6%
New light truck[4]	27.4	27.6	33.1	40.3	40.7	40.9	40.8	1.5%
On-road new light-duty vehicle[5]	25.6	25.6	30.6	37.7	38.3	38.7	38.9	1.6%
New car[5]	29.6	29.8	36.1	44.6	45.1	45.3	45.3	1.6%
New light truck[5]	22.0	22.1	26.5	32.3	32.6	32.7	32.7	1.5%
Light-duty stock[6]	21.5	21.9	25.0	28.5	32.3	35.1	37.0	2.0%
New commercial light truck[1]	18.1	18.1	20.6	24.2	24.4	24.6	24.6	1.1%
Stock commercial light truck[1]	15.2	15.5	18.0	20.3	22.4	23.8	24.4	1.7%
Freight truck	6.7	6.7	7.2	7.5	7.7	7.8	7.8	0.6%
(seat miles per gallon)								
Aircraft	64.2	65.9	67.4	68.7	70.2	72.0	74.1	0.4%
(ton miles per thousand Btu)								
Rail	3.4	3.5	3.6	3.8	3.9	4.1	4.2	0.7%
Domestic shipping	4.7	4.7	5.0	5.2	5.4	5.6	5.8	0.8%
Energy use by mode								
(quadrillion Btu)								
Light-duty vehicles	15.00	15.13	14.62	13.57	12.74	12.31	12.08	-0.8%
Commercial light trucks[1]	0.51	0.54	0.55	0.53	0.51	0.52	0.54	0.0%
Bus transportation	0.24	0.26	0.27	0.28	0.29	0.30	0.31	0.6%
Freight trucks	4.98	5.51	6.03	6.19	6.34	6.60	6.98	0.9%
Rail, passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.9%
Rail, freight	0.44	0.51	0.50	0.52	0.51	0.50	0.49	-0.1%
Shipping, domestic	0.10	0.10	0.10	0.09	0.08	0.08	0.07	-1.3%
Shipping, international	0.66	0.62	0.63	0.63	0.64	0.64	0.64	0.1%
Recreational boats	0.23	0.24	0.26	0.28	0.29	0.29	0.30	0.8%
Air	2.33	2.30	2.54	2.73	2.91	3.02	3.08	1.1%
Military use	0.71	0.67	0.63	0.64	0.68	0.72	0.77	0.5%
Lubricants	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.3%
Pipeline fuel	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Total	**26.11**	**26.96**	**27.18**	**26.54**	**26.12**	**26.11**	**26.41**	**-0.1%**

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Energy use by mode (million barrels per day oil equivalent)								
Light-duty vehicles	8.06	8.13	7.85	7.31	6.88	6.67	6.57	-0.8%
Commercial light trucks[1]	0.26	0.28	0.28	0.27	0.26	0.26	0.27	0.0%
Bus transportation	0.11	0.12	0.13	0.14	0.14	0.14	0.15	0.6%
Freight trucks	2.40	2.65	2.90	2.98	3.05	3.18	3.36	0.9%
Rail, passenger	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.9%
Rail, freight	0.21	0.24	0.24	0.25	0.24	0.24	0.23	-0.1%
Shipping, domestic	0.04	0.05	0.05	0.04	0.04	0.04	0.03	-1.3%
Shipping, international	0.29	0.27	0.29	0.29	0.29	0.29	0.29	0.2%
Recreational boats	0.12	0.13	0.14	0.15	0.15	0.16	0.16	0.8%
Air	1.13	1.11	1.23	1.32	1.40	1.46	1.49	1.1%
Military use	0.34	0.32	0.30	0.31	0.33	0.35	0.37	0.5%
Lubricants	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.3%
Pipeline fuel	0.35	0.42	0.40	0.42	0.44	0.44	0.45	0.3%
Total	**13.41**	**13.82**	**13.90**	**13.56**	**13.32**	**13.32**	**13.48**	**-0.1%**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II - User and Fuel Data), April 2011; Federal Highway Administration, *Highway Statistics 2012* (Washington, DC, January 2014); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 33* (Oak Ridge, TN, July 2014); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, June 2014); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Net generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1,478	1,550	1,670	1,685	1,674	1,665	1,663	0.3%
Petroleum	18	22	14	15	14	14	15	-1.6%
Natural gas[3]	1,000	894	867	954	1,073	1,143	1,198	1.1%
Nuclear power	769	789	804	808	808	812	833	0.2%
Pumped storage/other[4]	2	3	3	3	3	3	3	-0.1%
Renewable sources[5]	458	483	620	648	679	733	805	1.9%
Distributed generation (natural gas)	0	0	1	1	1	2	2	- -
Total	**3,726**	**3,741**	**3,978**	**4,113**	**4,252**	**4,372**	**4,518**	**0.7%**
Combined heat and power[6]								
Coal	22	22	26	26	26	26	26	0.5%
Petroleum	2	2	1	1	1	1	1	-4.0%
Natural gas	132	126	133	133	134	134	133	0.2%
Renewable sources	5	5	6	7	7	7	8	1.7%
Total	**164**	**158**	**166**	**167**	**168**	**168**	**167**	**0.2%**
Total net electric power sector generation	**3,890**	**3,899**	**4,144**	**4,280**	**4,420**	**4,540**	**4,686**	**0.7%**
Less direct use	13	13	14	14	14	14	14	0.2%
Net available to the grid	**3,877**	**3,886**	**4,131**	**4,267**	**4,406**	**4,527**	**4,672**	**0.7%**
End-use sector[7]								
Coal	13	13	13	13	13	13	13	0.0%
Petroleum	3	3	3	3	3	3	3	-0.4%
Natural gas	95	98	116	134	163	199	235	3.3%
Other gaseous fuels[8]	11	11	19	19	19	19	19	2.1%
Renewable sources[9]	39	42	53	60	70	82	97	3.1%
Other[10]	3	3	3	3	3	3	3	0.0%
Total end-use sector net generation	**164**	**171**	**207**	**233**	**271**	**320**	**370**	**2.9%**
Less direct use	126	132	167	190	225	269	313	3.3%
Total sales to the grid	**38**	**39**	**40**	**43**	**46**	**51**	**56**	**1.4%**
Total net electricity generation by fuel								
Coal	1,514	1,586	1,709	1,724	1,713	1,704	1,702	0.3%
Petroleum	23	27	18	18	18	18	18	-1.6%
Natural gas	1,228	1,118	1,117	1,223	1,371	1,478	1,569	1.3%
Nuclear power	769	789	804	808	808	812	833	0.2%
Renewable sources[5,9]	501	530	679	716	756	823	909	2.0%
Other[11]	19	20	25	25	25	25	25	0.8%
Total net electricity generation	**4,055**	**4,070**	**4,351**	**4,513**	**4,691**	**4,860**	**5,056**	**0.8%**
Net generation to the grid	**3,916**	**3,925**	**4,171**	**4,309**	**4,453**	**4,578**	**4,729**	**0.7%**
Net imports	**47**	**52**	**33**	**35**	**30**	**26**	**32**	**-1.8%**
Electricity sales by sector								
Residential	1,375	1,391	1,423	1,441	1,488	1,533	1,587	0.5%
Commercial	1,327	1,338	1,413	1,461	1,522	1,583	1,659	0.8%
Industrial	986	955	1,096	1,166	1,183	1,188	1,206	0.9%
Transportation	7	7	9	10	12	15	18	3.4%
Total	**3,695**	**3,691**	**3,941**	**4,078**	**4,205**	**4,319**	**4,470**	**0.7%**
Direct use	139	145	180	204	239	283	327	3.1%
Total electricity use	**3,834**	**3,836**	**4,121**	**4,282**	**4,444**	**4,602**	**4,797**	**0.8%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
End-use prices								
(2013 cents per kilowatthour)								
Residential	12.1	12.2	12.9	13.5	13.6	13.9	14.5	0.6%
Commercial	10.2	10.1	10.6	11.1	11.1	11.3	11.8	0.6%
Industrial	6.8	6.9	7.3	7.6	7.7	7.9	8.4	0.7%
Transportation	9.5	9.7	10.3	11.0	11.2	11.6	12.3	0.9%
All sectors average	**10.0**	**10.1**	**10.5**	**11.0**	**11.1**	**11.3**	**11.8**	**0.6%**
(nominal cents per kilowatthour)								
Residential	11.9	12.2	14.6	16.6	18.3	20.5	23.5	2.5%
Commercial	10.1	10.1	12.0	13.6	14.9	16.6	19.1	2.4%
Industrial	6.7	6.9	8.2	9.4	10.3	11.7	13.6	2.6%
Transportation	9.3	9.7	11.7	13.6	15.0	17.0	19.9	2.7%
All sectors average	**9.8**	**10.1**	**11.9**	**13.5**	**14.8**	**16.6**	**19.2**	**2.4%**
Prices by service category								
(2013 cents per kilowatthour)								
Generation	6.5	6.6	6.6	7.0	7.0	7.1	7.6	0.5%
Transmission	0.9	0.9	1.1	1.2	1.2	1.2	1.3	1.2%
Distribution	2.5	2.6	2.8	2.9	2.9	3.0	3.0	0.6%
(nominal cents per kilowatthour)								
Generation	6.4	6.6	7.5	8.6	9.3	10.5	12.3	2.3%
Transmission	0.9	0.9	1.2	1.4	1.6	1.8	2.1	3.0%
Distribution	2.5	2.6	3.2	3.6	3.9	4.4	4.9	2.4%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	3.43	3.27	1.42	1.44	1.44	1.47	1.53	-2.8%
Nitrogen oxide (million short tons)	1.68	1.69	1.57	1.57	1.56	1.57	1.57	-0.3%
Mercury (short tons)	26.69	27.94	6.58	6.53	6.43	6.40	6.41	-5.3%

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes plants that only produce electricity and that have a regulatory status.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2013 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014), and supporting databases. 2012 and 2013 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2012 and 2013 electricity prices by service category: EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. **Projections**: EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Electric power sector[2]								
Power only[3]								
Coal[4]	300.2	296.1	255.4	252.8	252.8	252.8	252.9	-0.6%
Oil and natural gas steam[4,5]	99.2	94.6	87.5	78.3	73.2	69.2	68.2	-1.2%
Combined cycle	185.3	188.3	203.2	211.9	233.6	255.1	281.3	1.5%
Combustion turbine/diesel	136.4	139.6	140.1	144.2	151.8	160.7	172.6	0.8%
Nuclear power[6]	102.1	98.9	101.4	101.4	101.6	102.1	104.9	0.2%
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4	0.0%
Fuel cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0%
Renewable sources[7]	148.1	153.3	187.1	190.2	196.6	209.7	229.2	1.5%
Distributed generation (natural gas)[8]	0.0	0.0	0.7	1.1	1.7	2.4	3.1	- -
Total	**993.7**	**993.2**	**997.9**	**1,002.4**	**1,033.7**	**1,074.4**	**1,134.6**	**0.5%**
Combined heat and power[9]								
Coal	4.5	4.3	4.1	4.1	4.1	4.1	4.1	-0.2%
Oil and natural gas steam[5]	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0%
Combined cycle	25.7	25.7	26.0	26.0	26.0	26.0	26.0	0.0%
Combustion turbine/diesel	3.1	3.1	3.1	3.1	3.1	3.1	3.1	0.0%
Renewable sources[7]	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.1%
Total	**35.6**	**35.4**	**35.6**	**35.6**	**35.6**	**35.6**	**35.6**	**0.0%**
Cumulative planned additions[10]								
Coal	- -	- -	0.7	0.7	0.7	0.7	0.7	- -
Oil and natural gas steam[5]	- -	- -	0.4	0.4	0.4	0.4	0.4	- -
Combined cycle	- -	- -	14.2	14.2	14.2	14.2	14.2	- -
Combustion turbine/diesel	- -	- -	1.6	1.6	1.6	1.6	1.6	- -
Nuclear power	- -	- -	5.5	5.5	5.5	5.5	5.5	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[7]	- -	- -	30.5	30.5	30.5	30.5	30.5	- -
Distributed generation[8]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Total	**- -**	**- -**	**52.8**	**52.8**	**52.8**	**52.8**	**52.8**	**- -**
Cumulative unplanned additions[10]								
Coal	- -	- -	0.3	0.3	0.3	0.3	0.4	- -
Oil and natural gas steam[5]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	- -	- -	7.7	17.3	39.0	60.5	86.9	- -
Combustion turbine/diesel	- -	- -	3.8	8.5	16.8	26.1	37.9	- -
Nuclear power	- -	- -	0.0	0.0	0.1	0.6	3.5	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[7]	- -	- -	4.0	7.1	13.4	26.6	46.1	- -
Distributed generation[8]	- -	- -	0.7	1.1	1.7	2.4	3.1	- -
Total	**- -**	**- -**	**16.5**	**34.3**	**71.4**	**116.5**	**177.9**	**- -**
Cumulative electric power sector additions[10]	**- -**	**- -**	**69.3**	**87.1**	**124.2**	**169.4**	**230.7**	**- -**
Cumulative retirements[11]								
Coal	- -	- -	37.4	40.1	40.1	40.1	40.1	- -
Oil and natural gas steam[5]	- -	- -	11.8	21.0	26.1	30.1	31.0	- -
Combined cycle	- -	- -	7.1	8.0	8.0	8.0	8.3	- -
Combustion turbine/diesel	- -	- -	4.9	5.5	6.1	6.5	6.5	- -
Nuclear power	- -	- -	3.2	3.2	3.2	3.2	3.2	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[7]	- -	- -	0.6	0.6	0.6	0.6	0.6	- -
Total	**- -**	**- -**	**65.0**	**78.3**	**84.1**	**88.5**	**89.7**	**- -**
Total electric power sector capacity	**1,029**	**1,029**	**1,033**	**1,038**	**1,069**	**1,110**	**1,170**	**0.5%**

Table A9. Electricity generating capacity (continued)
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
End-use generators[12]								
Coal	3.4	3.4	3.4	3.4	3.4	3.4	3.4	0.0%
Petroleum	0.9	0.9	0.9	0.9	0.9	0.9	0.9	-0.4%
Natural gas	16.3	16.9	19.5	22.7	27.6	33.6	38.9	3.1%
Other gaseous fuels[13]	2.1	2.1	2.8	2.8	2.8	2.8	2.8	1.0%
Renewable sources[7]	10.4	12.1	18.2	22.4	28.6	36.0	44.6	4.9%
Other[14]	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0%
Total	**33.6**	**36.0**	**45.3**	**52.8**	**63.8**	**77.2**	**91.1**	**3.5%**
Cumulative capacity additions[10]	**- -**	**- -**	**10.5**	**18.0**	**29.1**	**42.6**	**56.5**	**- -**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes plants that only produce electricity and that have a regulatory status. Includes capacity increases (uprates) at existing units.
[4]Coal and oil and natural gas steam capacity reflect the impact of 4.1 GW of existing coal capacity converting to gas steam capacity.
[5]Includes oil-, gas-, and dual-fired capacity.
[6]Nuclear capacity includes 0.2 gigawatts of uprates.
[7]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[8]Primarily peak load capacity fueled by natural gas.
[9]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[10]Cumulative additions after December 31, 2013.
[11]Cumulative retirements after December 31, 2013.
[12]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]Includes refinery gas and still gas.
[14]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A10. Electricity trade
(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Interregional electricity trade								
Gross domestic sales								
Firm power	156	157	122	63	28	28	28	-6.2%
Economy	184	115	195	214	207	232	268	3.2%
Total	**340**	**272**	**318**	**277**	**235**	**260**	**296**	**0.3%**
Gross domestic sales (million 2013 dollars)								
Firm power	9,711	9,802	7,622	3,952	1,722	1,722	1,722	-6.2%
Economy	6,217	4,772	9,376	11,934	11,963	14,056	18,159	5.1%
Total	**15,929**	**14,574**	**16,998**	**15,886**	**13,685**	**15,778**	**19,881**	**1.2%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	15.9	15.8	20.4	16.4	14.0	14.0	14.0	-0.5%
Economy	43.1	47.9	28.0	34.4	30.6	26.2	32.1	-1.5%
Total	**59.0**	**63.7**	**48.4**	**50.7**	**44.6**	**40.2**	**46.1**	**-1.2%**
Exports to Canada and Mexico								
Firm power	2.7	2.3	1.5	0.5	0.0	0.0	0.0	- -
Economy	8.8	9.1	14.0	14.7	14.7	14.4	14.4	1.7%
Total	**11.5**	**11.4**	**15.4**	**15.2**	**14.7**	**14.4**	**14.4**	**0.9%**

- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports. Firm power sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Sources: 2012 and 2013 interregional firm electricity trade data: 2013 seasonal reliability assessments from North American Electric Reliability Council regional entities and Independent System Operators. 2012 and 2013 interregional economy electricity trade are model results. 2012 and 2013 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2012*, DOE/EIA-0348(2012) (Washington, DC, December 2013). 2012 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2012*. 2013 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2013*. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A11. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil								
Domestic crude production[1]	6.50	7.44	10.60	10.28	10.04	9.38	9.43	0.9%
Alaska	0.53	0.52	0.42	0.32	0.24	0.18	0.34	-1.6%
Lower 48 states	5.98	6.92	10.18	9.96	9.80	9.20	9.09	1.0%
Net imports	8.46	7.60	5.51	6.09	6.44	7.35	7.58	0.0%
Gross imports	8.53	7.73	6.14	6.72	7.07	7.98	8.21	0.2%
Exports	0.07	0.13	0.63	0.63	0.63	0.63	0.63	5.9%
Other crude supply[2]	0.04	0.27	0.00	0.00	0.00	0.00	0.00	- -
Total crude supply	**15.00**	**15.30**	**16.11**	**16.37**	**16.48**	**16.73**	**17.01**	**0.4%**
Net product imports	-1.05	-1.37	-2.80	-3.24	-3.56	-3.94	-4.26	- -
Gross refined product imports[3]	0.82	0.82	1.21	1.28	1.31	1.31	1.26	1.6%
Unfinished oil imports	0.60	0.66	0.60	0.56	0.52	0.49	0.45	-1.4%
Blending component imports	0.62	0.60	0.59	0.55	0.49	0.45	0.40	-1.5%
Exports	3.08	3.43	5.20	5.63	5.89	6.18	6.36	2.3%
Refinery processing gain[4]	1.06	1.09	0.98	1.00	0.97	0.99	0.98	-0.4%
Product stock withdrawal	-0.07	0.11	0.00	0.00	0.00	0.00	0.00	- -
Natural gas plant liquids	2.41	2.61	4.04	4.16	4.19	4.13	4.07	1.7%
Supply from renewable sources	0.88	0.93	1.01	1.01	1.01	1.04	1.12	0.7%
Ethanol	0.82	0.83	0.84	0.84	0.84	0.87	0.95	0.5%
Domestic production	0.84	0.85	0.86	0.86	0.86	0.87	0.93	0.4%
Net imports	-0.02	-0.02	-0.02	-0.02	-0.02	0.00	0.02	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biodiesel	0.06	0.10	0.14	0.11	0.11	0.11	0.11	0.4%
Domestic production	0.06	0.09	0.13	0.10	0.10	0.10	0.10	0.3%
Net imports	-0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.9%
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other biomass-derived liquids[5]	0.00	0.00	0.03	0.06	0.06	0.06	0.06	31.9%
Domestic production	0.00	0.00	0.03	0.06	0.06	0.06	0.06	31.9%
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other[6]	0.19	0.21	0.28	0.29	0.30	0.31	0.32	1.6%
Total primary supply[7]	**18.43**	**18.87**	**19.62**	**19.59**	**19.38**	**19.26**	**19.24**	**0.1%**
Product supplied								
by fuel								
Liquefied petroleum gases and other[8]	2.30	2.50	2.91	3.19	3.30	3.27	3.25	1.0%
Motor gasoline[9]	8.69	8.85	8.49	7.89	7.41	7.16	7.05	-0.8%
of which: E85[10]	0.01	0.01	0.02	0.08	0.13	0.16	0.19	9.9%
Jet fuel[11]	1.40	1.43	1.55	1.64	1.75	1.82	1.87	1.0%
Distillate fuel oil[12]	3.74	3.83	4.26	4.31	4.34	4.38	4.38	0.5%
of which: Diesel	3.46	3.56	3.94	4.02	4.09	4.15	4.17	0.6%
Residual fuel oil	0.37	0.32	0.27	0.28	0.28	0.28	0.28	-0.4%
Other[13]	1.97	2.04	2.18	2.30	2.33	2.37	2.43	0.7%
by sector								
Residential and commercial	0.82	0.86	0.76	0.71	0.67	0.64	0.61	-1.3%
Industrial[14]	4.49	4.69	5.50	5.90	6.04	6.04	6.09	1.0%
Transportation	13.04	13.36	13.46	13.08	12.79	12.71	12.66	-0.2%
Electric power[15]	0.10	0.12	0.08	0.08	0.08	0.08	0.08	-1.4%
Unspecified sector[16]	0.02	-0.12	-0.15	-0.16	-0.17	-0.17	-0.17	- -
Total product supplied	**18.47**	**18.96**	**19.65**	**19.61**	**19.41**	**19.29**	**19.27**	**0.1%**
Discrepancy[17]	-0.03	-0.10	-0.03	-0.02	-0.03	-0.03	-0.03	- -

Table A11. Petroleum and other liquids supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Domestic refinery distillation capacity[18]	17.4	17.8	18.8	18.8	18.8	18.8	18.8	0.2%
Capacity utilization rate (percent)[19]	88.7	88.3	87.8	89.0	89.4	90.7	92.0	0.2%
Net import share of product supplied (percent)	40.1	33.0	13.7	14.5	14.8	17.7	17.4	-2.3%
Net expenditures for imported crude oil and petroleum products (billion 2013 dollars)	345	308	167	211	259	339	405	1.0%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). Other 2013 data: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A12. Petroleum and other liquids prices
(2013 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil prices (2013 dollars per barrel)								
Brent spot	113	109	79	91	106	122	141	1.0%
West Texas Intermediate spot	96	98	73	85	99	116	136	1.2%
Average imported refiners acquisition cost[1]	103	98	71	82	96	112	131	1.1%
Brent / West Texas Intermediate spread	17.8	10.7	6.2	6.1	6.2	6.0	5.6	-2.4%
Delivered sector product prices								
Residential								
Propane	2.22	2.13	2.10	2.16	2.23	2.33	2.43	0.5%
Distillate fuel oil	3.79	3.78	2.99	3.28	3.65	4.08	4.56	0.7%
Commercial								
Distillate fuel oil	3.69	3.68	2.89	3.20	3.56	3.99	4.47	0.7%
Residual fuel oil	3.43	3.31	2.12	2.39	2.71	3.08	3.64	0.4%
Residual fuel oil (2013 dollars per barrel)	144	139	89	101	114	129	153	0.4%
Industrial[2]								
Propane	1.95	1.85	1.79	1.87	1.96	2.09	2.24	0.7%
Distillate fuel oil	3.76	3.75	2.91	3.23	3.58	4.00	4.49	0.7%
Residual fuel oil	3.09	3.00	2.00	2.27	2.58	2.95	3.51	0.6%
Residual fuel oil (2013 dollars per barrel)	130	126	84	95	108	124	147	0.6%
Transportation								
Propane	2.31	2.24	2.19	2.25	2.32	2.42	2.52	0.4%
E85[3]	3.39	3.14	2.90	2.77	2.98	3.16	3.38	0.3%
Ethanol wholesale price	2.58	2.37	2.49	2.47	2.35	2.49	2.64	0.4%
Motor gasoline[4]	3.72	3.55	2.74	2.95	3.20	3.53	3.90	0.3%
Jet fuel[5]	3.10	2.94	2.17	2.47	2.88	3.31	3.81	1.0%
Diesel fuel (distillate fuel oil)[6]	3.94	3.86	3.17	3.49	3.84	4.26	4.75	0.8%
Residual fuel oil	3.00	2.89	1.74	2.00	2.30	2.64	3.03	0.2%
Residual fuel oil (2013 dollars per barrel)	126	122	73	84	97	111	127	0.2%
Electric power[7]								
Distillate fuel oil	3.34	3.33	2.60	2.90	3.28	3.70	4.19	0.9%
Residual fuel oil	3.12	2.83	1.71	1.99	2.30	2.67	3.23	0.5%
Residual fuel oil (2013 dollars per barrel)	131	119	72	83	97	112	136	0.5%
Average prices, all sectors[8]								
Propane	2.09	2.00	1.93	1.99	2.06	2.18	2.30	0.5%
Motor gasoline[4]	3.70	3.53	2.74	2.95	3.20	3.53	3.90	0.4%
Jet fuel[5]	3.10	2.94	2.17	2.47	2.88	3.31	3.81	1.0%
Distillate fuel oil	3.89	3.83	3.11	3.43	3.78	4.20	4.69	0.8%
Residual fuel oil	3.04	2.90	1.83	2.10	2.40	2.75	3.22	0.4%
Residual fuel oil (2013 dollars per barrel)	128	122	77	88	101	116	135	0.4%
Average	**3.29**	**3.16**	**2.46**	**2.65**	**2.89**	**3.23**	**3.62**	**0.5%**

Table A12. Petroleum and other liquids prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil prices (nominal dollars per barrel)								
Brent spot	112	109	90	112	142	180	229	2.8%
West Texas Intermediate spot	94	98	83	105	133	171	220	3.0%
Average imported refiners acquisition cost[1]	101	98	80	102	129	165	212	2.9%
Delivered sector product prices								
Residential								
Propane	2.19	2.13	2.38	2.66	2.99	3.42	3.94	2.3%
Distillate fuel oil	3.73	3.78	3.39	4.04	4.90	5.99	7.40	2.5%
Commercial								
Distillate fuel oil	3.63	3.68	3.28	3.94	4.78	5.86	7.25	2.5%
Residual fuel oil	3.38	3.31	2.41	2.95	3.63	4.53	5.90	2.2%
Residual fuel oil (nominal dollars per barrel)	142	139	101	124	153	190	248	2.2%
Industrial[2]								
Propane	1.92	1.85	2.04	2.30	2.63	3.08	3.62	2.5%
Distillate fuel oil	3.71	3.75	3.30	3.98	4.80	5.89	7.28	2.5%
Residual fuel oil	3.05	3.00	2.26	2.79	3.46	4.34	5.69	2.4%
Residual fuel oil (nominal dollars per barrel)	128	126	95	117	145	182	239	2.4%
Transportation								
Propane	2.28	2.24	2.49	2.78	3.12	3.56	4.09	2.2%
E85[3]	3.34	3.14	3.29	3.41	3.99	4.65	5.48	2.1%
Ethanol wholesale price	2.55	2.37	2.83	3.04	3.15	3.67	4.27	2.2%
Motor gasoline[4]	3.67	3.55	3.10	3.63	4.29	5.18	6.32	2.2%
Jet fuel[5]	3.06	2.94	2.47	3.05	3.86	4.87	6.18	2.8%
Diesel fuel (distillate fuel oil)[6]	3.89	3.86	3.60	4.30	5.15	6.26	7.70	2.6%
Residual fuel oil	2.95	2.89	1.98	2.46	3.08	3.88	4.92	2.0%
Residual fuel oil (nominal dollars per barrel)	124	122	83	103	129	163	207	2.0%
Electric power[7]								
Distillate fuel oil	3.29	3.33	2.95	3.57	4.39	5.45	6.79	2.7%
Residual fuel oil	3.07	2.83	1.94	2.45	3.09	3.93	5.24	2.3%
Residual fuel oil (nominal dollars per barrel)	129	119	82	103	130	165	220	2.3%
Average prices, all sectors[8]								
Propane	2.06	2.00	2.19	2.45	2.77	3.20	3.73	2.3%
Motor gasoline[4]	3.64	3.53	3.10	3.63	4.29	5.18	6.32	2.2%
Jet fuel[5]	3.06	2.94	2.47	3.05	3.86	4.87	6.18	2.8%
Distillate fuel oil	3.83	3.83	3.52	4.22	5.07	6.18	7.61	2.6%
Residual fuel oil	2.99	2.90	2.07	2.58	3.22	4.04	5.21	2.2%
Residual fuel oil (nominal dollars per barrel)	126	122	87	108	135	170	219	2.2%
Average	**3.24**	**3.16**	**2.79**	**3.26**	**3.88**	**4.75**	**5.86**	**2.3%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2012 and 2013 average imported crude oil price: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 and 2013 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2012 and 2013 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2012 and 2013 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Supply								
Dry gas production[1]	24.06	24.40	28.82	30.51	33.01	34.14	35.45	1.4%
Supplemental natural gas[2]	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.6%
Net imports	1.52	1.29	-2.55	-3.50	-4.81	-5.19	-5.62	- -
Pipeline[3]	1.37	1.20	-0.48	-1.01	-1.52	-1.90	-2.33	- -
Liquefied natural gas	0.15	0.09	-2.08	-2.49	-3.29	-3.29	-3.29	- -
Total supply	**25.64**	**25.75**	**26.33**	**27.07**	**28.27**	**29.01**	**29.90**	**0.6%**
Consumption by sector								
Residential	4.15	4.92	4.50	4.42	4.40	4.31	4.20	-0.6%
Commercial	2.90	3.28	3.21	3.20	3.33	3.47	3.61	0.4%
Industrial[4]	7.21	7.41	8.10	8.24	8.41	8.52	8.66	0.6%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	9.11	8.16	7.61	8.13	8.81	9.17	9.38	0.5%
Transportation[8]	0.04	0.05	0.07	0.10	0.17	0.31	0.70	10.3%
Pipeline fuel	0.73	0.86	0.83	0.87	0.91	0.92	0.93	0.3%
Lease and plant fuel[9]	1.40	1.48	1.82	1.92	2.05	2.12	2.23	1.5%
Total consumption	**25.53**	**26.16**	**26.14**	**26.88**	**28.08**	**28.82**	**29.70**	**0.5%**
Discrepancy[10]	**0.11**	**-0.41**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**- -**
Natural gas spot price at Henry Hub								
(2013 dollars per million Btu)	2.79	3.73	4.88	5.46	5.69	6.60	7.85	2.8%
(nominal dollars per million Btu)	2.75	3.73	5.54	6.72	7.63	9.70	12.73	4.7%
Delivered prices								
(2013 dollars per thousand cubic feet)								
Residential	10.86	10.29	11.92	13.07	13.15	14.13	15.90	1.6%
Commercial	8.36	8.35	9.82	10.83	10.69	11.44	12.97	1.6%
Industrial[4]	3.94	4.68	6.35	7.07	6.99	7.75	9.03	2.5%
Electric power[7]	3.59	4.51	5.52	6.43	6.38	7.15	8.49	2.4%
Transportation[11]	20.93	18.13	18.27	17.23	16.13	17.60	20.18	0.4%
Average[12]	**5.61**	**6.32**	**7.66**	**8.50**	**8.40**	**9.22**	**10.76**	**2.0%**
(nominal dollars per thousand cubic feet)								
Residential	10.70	10.29	13.52	16.09	17.62	20.77	25.77	3.5%
Commercial	8.24	8.35	11.14	13.34	14.33	16.81	21.03	3.5%
Industrial[4]	3.88	4.68	7.20	8.71	9.37	11.39	14.64	4.3%
Electric power[7]	3.54	4.51	6.26	7.92	8.55	10.51	13.76	4.2%
Transportation[11]	20.62	18.13	20.73	21.21	21.62	25.87	32.72	2.2%
Average[12]	**5.53**	**6.32**	**8.68**	**10.46**	**11.27**	**13.55**	**17.44**	**3.8%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes use for lease and plant fuel.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as fuel in motor vehicles, trains, and ships.
[9]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2012 and 2013 values include net storage injections.
[11]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[12]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2012 and 2013 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2012 and 2013 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2012 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014), EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014), and estimated State and Federal motor fuel taxes and dispensing costs or charges. 2013 transportation sector delivered prices are model results. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil								
Lower 48 average wellhead price[1]								
(2013 dollars per barrel)	**96**	**97**	**75**	**87**	**101**	**117**	**136**	**1.3%**
Production (million barrels per day)[2]								
United States total	6.50	7.44	10.60	10.28	10.04	9.38	9.43	0.9%
Lower 48 onshore	4.60	5.57	8.03	8.01	7.60	7.07	6.92	0.8%
Tight oil[3]	2.19	3.15	5.60	5.31	4.83	4.40	4.29	1.1%
Carbon dioxide enhanced oil recovery	0.28	0.28	0.35	0.47	0.58	0.69	0.83	4.1%
Other	2.12	2.14	2.08	2.23	2.19	1.98	1.80	-0.6%
Lower 48 offshore	1.38	1.36	2.15	1.95	2.21	2.14	2.17	1.7%
State	0.07	0.07	0.05	0.04	0.03	0.03	0.02	-3.8%
Federal	1.31	1.29	2.10	1.92	2.18	2.11	2.14	1.9%
Alaska	0.53	0.52	0.42	0.32	0.24	0.18	0.34	-1.6%
Onshore	0.47	0.45	0.30	0.23	0.18	0.14	0.12	-4.9%
State offshore	0.06	0.06	0.12	0.09	0.06	0.04	0.02	-3.6%
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.20	15.9%
Lower 48 end of year reserves[2]								
(billion barrels)	**30.1**	**29.4**	**37.4**	**39.4**	**42.6**	**43.4**	**44.8**	**1.6%**
Natural gas plant liquids production								
(million barrels per day)								
United States total	2.41	2.61	4.04	4.16	4.20	4.13	4.07	1.7%
Lower 48 onshore	2.18	2.39	3.82	3.94	3.92	3.87	3.79	1.7%
Lower 48 offshore	0.20	0.18	0.19	0.20	0.26	0.25	0.26	1.3%
Alaska	0.03	0.03	0.02	0.02	0.01	0.01	0.02	-1.4%
Natural gas								
Natural gas spot price at Henry Hub								
(2013 dollars per million Btu)	2.79	3.73	4.88	5.46	5.69	6.60	7.85	2.8%
Dry production (trillion cubic feet)[4]								
United States total	24.06	24.40	28.82	30.51	33.01	34.14	35.45	1.4%
Lower 48 onshore	22.16	22.63	26.52	28.10	29.05	30.26	31.49	1.2%
Tight gas	4.78	4.38	5.21	5.55	5.99	6.40	6.97	1.7%
Shale gas and tight oil plays[3]	10.16	11.34	15.44	17.03	17.85	18.85	19.58	2.0%
Coalbed methane	1.64	1.29	1.45	1.32	1.24	1.24	1.25	-0.1%
Other	5.58	5.61	4.42	4.19	3.97	3.77	3.69	-1.5%
Lower 48 offshore	1.57	1.46	2.03	2.16	2.79	2.73	2.81	2.5%
State	0.14	0.11	0.06	0.04	0.03	0.02	0.02	-5.9%
Federal	1.42	1.35	1.98	2.13	2.76	2.70	2.79	2.7%
Alaska	0.33	0.32	0.27	0.25	1.18	1.16	1.15	4.9%
Onshore	0.33	0.32	0.27	0.25	1.18	1.16	1.15	4.9%
State offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lower 48 end of year dry reserves[4]								
(trillion cubic feet)	**298**	**293**	**309**	**316**	**329**	**338**	**345**	**0.6%**
Supplemental gas supplies (trillion cubic feet)[5]	**0.06**	**0.05**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.6%**
Total lower 48 wells drilled (thousands)	**44.7**	**44.5**	**43.4**	**47.4**	**52.1**	**54.0**	**56.7**	**0.9%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 and 2013 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2012 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2012) (Washington, DC, April 2014). 2012 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2012 and 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2013 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2012 and 2013 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A15. Coal supply, disposition, and prices
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Production[1]								
Appalachia	293	272	260	248	243	235	228	-0.6%
Interior	180	183	219	235	258	278	300	1.8%
West	543	530	592	622	617	597	589	0.4%
East of the Mississippi	423	407	428	426	442	453	467	0.5%
West of the Mississippi	593	578	643	679	676	658	650	0.4%
Total	**1,016**	**985**	**1,071**	**1,105**	**1,118**	**1,111**	**1,117**	**0.5%**
Waste coal supplied[2]	**11**	**10**	**11**	**10**	**10**	**10**	**10**	**0.0%**
Net imports								
Imports[3]	8	7	1	1	1	1	1	-6.8%
Exports	126	118	95	112	130	131	141	0.7%
Total	**-118**	**-110**	**-94**	**-110**	**-129**	**-130**	**-140**	**0.9%**
Total supply[4]	**909**	**885**	**987**	**1,005**	**999**	**990**	**988**	**0.4%**
Consumption by sector								
Commercial and institutional	2	2	2	2	2	2	2	0.5%
Coke plants	21	21	21	21	20	19	18	-0.7%
Other industrial[5]	43	43	47	47	48	48	49	0.5%
Coal-to-liquids heat and power	0	0	0	0	0	0	0	- -
Coal to liquids production	0	0	0	0	0	0	0	- -
Electric power[6]	824	858	917	935	930	921	919	0.3%
Total	**889**	**925**	**987**	**1,005**	**999**	**990**	**988**	**0.2%**
Discrepancy and stock change[7]	**20**	**-40**	**0**	**0**	**0**	**0**	**0**	**- -**
Average minemouth price[8]								
(2013 dollars per short ton)	40.5	37.2	37.9	40.3	43.7	46.7	49.2	1.0%
(2013 dollars per million Btu)	2.01	1.84	1.88	2.02	2.18	2.32	2.44	1.0%
Delivered prices[9]								
(2013 dollars per short ton)								
Commercial and institutional	92.1	90.5	86.4	89.2	92.0	95.0	99.2	0.3%
Coke plants	193.4	157.0	165.8	177.7	189.5	197.3	204.4	1.0%
Other industrial[5]	71.4	69.3	70.3	73.6	76.5	79.1	82.5	0.6%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(2013 dollars per short ton)	46.5	45.2	45.7	48.2	50.6	53.1	55.6	0.8%
(2013 dollars per million Btu)	2.41	2.34	2.38	2.54	2.67	2.79	2.92	0.8%
Average	**51.5**	**49.1**	**49.5**	**52.2**	**54.7**	**57.1**	**59.7**	**0.7%**
Exports[10]	120.2	95.1	100.9	107.2	112.7	118.9	120.7	0.9%

Table A15. Coal supply, disposition, and prices (continued)
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Average minemouth price[8]								
(nominal dollars per short ton)	40.0	37.2	43.0	49.7	58.6	68.6	79.8	2.9%
(nominal dollars per million Btu)	1.98	1.84	2.14	2.48	2.92	3.41	3.96	2.9%
Delivered prices[9]								
(nominal dollars per short ton)								
Commercial and institutional	90.8	90.5	98.0	109.9	123.4	139.7	160.8	2.2%
Coke plants	190.6	157.0	188.0	218.7	254.0	289.9	331.3	2.8%
Other industrial[5]	70.3	69.3	79.7	90.7	102.5	116.3	133.8	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(nominal dollars per short ton)	45.8	45.2	51.8	59.4	67.9	78.0	90.1	2.6%
(nominal dollars per million Btu)	2.37	2.34	2.70	3.13	3.58	4.10	4.73	2.6%
Average	**50.7**	**49.1**	**56.2**	**64.3**	**73.3**	**84.0**	**96.8**	**2.6%**
Exports[10]	118.4	95.1	114.4	131.9	151.1	174.7	195.6	2.7%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[9]Prices weighted by consumption; weighted average excludes commercial and institutional prices, and export free-alongside-ship prices.
[10]Free-alongside-ship price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015); EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014); and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Electric power sector[1]								
Net summer capacity								
Conventional hydroelectric power	78.1	78.3	79.2	79.6	79.7	79.8	80.1	0.1%
Geothermal[2]	2.6	2.6	3.8	5.3	7.0	8.2	9.1	4.7%
Municipal waste[3]	3.6	3.7	3.8	3.8	3.8	3.8	3.8	0.1%
Wood and other biomass[4]	2.9	3.3	3.5	3.5	3.6	4.2	5.5	1.8%
Solar thermal	0.5	1.3	1.8	1.8	1.8	1.8	1.8	1.2%
Solar photovoltaic[5]	2.6	5.2	14.4	14.7	15.7	17.9	22.2	5.5%
Wind	59.2	60.3	82.0	83.0	86.3	95.6	108.2	2.2%
Offshore wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total electric power sector capacity	**149.4**	**154.7**	**188.6**	**191.6**	**198.0**	**211.2**	**230.6**	**1.5%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	273.9	265.7	291.0	292.8	293.4	293.8	295.6	0.4%
Geothermal[2]	15.6	16.5	26.8	38.5	52.4	62.3	69.6	5.5%
Biogenic municipal waste[6]	16.9	16.5	20.0	20.3	20.1	20.0	20.2	0.8%
Wood and other biomass	11.1	12.2	24.7	36.2	40.4	47.1	58.8	6.0%
Dedicated plants	9.9	11.1	13.4	15.1	16.7	20.4	30.3	3.8%
Cofiring	1.2	1.1	11.3	21.1	23.7	26.7	28.5	12.7%
Solar thermal	0.9	0.9	3.6	3.6	3.6	3.6	3.6	5.1%
Solar photovoltaic[5]	3.3	8.0	29.7	30.3	32.6	37.6	47.1	6.8%
Wind	140.7	167.6	230.6	233.8	243.3	276.1	317.1	2.4%
Offshore wind	0.0	0.0	0.1	0.1	0.1	0.1	0.1	- -
Total electric power sector generation	**462.3**	**487.4**	**626.4**	**655.6**	**685.9**	**740.7**	**812.1**	**1.9%**
End-use sectors[7]								
Net summer capacity								
Conventional hydroelectric power	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0%
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Municipal waste[8]	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0%
Biomass	4.9	5.0	5.4	5.4	5.4	5.5	5.6	0.4%
Solar photovoltaic[5]	4.6	6.2	11.4	15.5	21.5	28.7	36.7	6.8%
Wind	0.2	0.2	0.7	0.7	0.9	1.1	1.5	7.7%
Total end-use sector capacity	**10.4**	**12.1**	**18.2**	**22.4**	**28.6**	**36.0**	**44.6**	**4.9%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.0%
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Municipal waste[8]	3.6	3.6	3.6	3.6	3.6	3.6	3.6	0.0%
Biomass	26.5	27.2	29.1	29.3	29.4	29.4	30.5	0.4%
Solar photovoltaic[5]	7.1	9.6	17.9	24.8	34.7	46.3	59.3	7.0%
Wind	0.2	0.3	0.9	1.0	1.2	1.5	2.1	8.0%
Total end-use sector generation	**38.8**	**42.1**	**52.9**	**60.1**	**70.2**	**82.3**	**96.9**	**3.1%**

Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Total, all sectors								
Net summer capacity								
Conventional hydroelectric power	78.4	78.5	79.5	79.9	80.0	80.1	80.4	0.1%
Geothermal	2.6	2.6	3.8	5.3	7.0	8.2	9.1	4.7%
Municipal waste	4.1	4.1	4.3	4.3	4.3	4.3	4.3	0.1%
Wood and other biomass[4]	7.8	8.3	8.9	8.9	9.1	9.6	11.1	1.1%
Solar[5]	7.6	12.7	27.6	31.9	39.0	48.3	60.6	6.0%
Wind	59.4	60.5	82.7	83.8	87.3	96.7	109.7	2.2%
Total capacity, all sectors	**159.8**	**166.8**	**206.8**	**214.1**	**226.6**	**247.2**	**275.2**	**1.9%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	275.2	267.1	292.3	294.2	294.7	295.2	297.0	0.4%
Geothermal	15.6	16.5	26.8	38.5	52.4	62.3	69.6	5.5%
Municipal waste	20.6	20.1	23.7	23.9	23.7	23.7	23.8	0.6%
Wood and other biomass	37.6	39.4	53.8	65.5	69.8	76.5	89.3	3.1%
Solar[5]	11.2	18.5	51.3	58.7	70.9	87.5	110.1	6.8%
Wind	141.0	167.8	231.5	234.9	244.6	277.8	319.3	2.4%
Total generation, all sectors	**501.2**	**529.5**	**679.4**	**715.6**	**756.2**	**823.0**	**909.1**	**2.0%**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2013, EIA estimates that as much as 274 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2013, plus an additional 573 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010), and Table 12 (U.S. photovoltaic module shipments by end use, sector, and type) in U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2011* (Washington, DC, September 2012) and U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2012* (Washington, DC, December 2013). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[6]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2013 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2012 and 2013 generation: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Marketed renewable energy[1]								
Residential (wood)	**0.44**	**0.58**	**0.41**	**0.39**	**0.38**	**0.36**	**0.35**	**-1.8%**
Commercial (biomass)	**0.11**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.0%**
Industrial[2]	**2.24**	**2.20**	**2.33**	**2.39**	**2.39**	**2.39**	**2.49**	**0.5%**
Conventional hydroelectric power	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.0%
Municipal waste[3]	0.17	0.19	0.19	0.19	0.19	0.19	0.19	0.2%
Biomass	1.32	1.28	1.33	1.39	1.39	1.38	1.42	0.4%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Transportation	**1.18**	**1.26**	**1.43**	**1.42**	**1.42**	**1.46**	**1.57**	**0.8%**
Ethanol used in E85[4]	0.01	0.01	0.02	0.08	0.13	0.16	0.19	9.9%
Ethanol used in gasoline blending	1.05	1.06	1.07	1.00	0.95	0.96	1.05	0.0%
Biodiesel used in distillate blending	0.11	0.19	0.27	0.21	0.21	0.21	0.21	0.4%
Biobutanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from biomass	0.00	0.00	0.01	0.02	0.02	0.02	0.02	22.0%
Renewable diesel and gasoline[5]	0.00	0.00	0.06	0.11	0.11	0.11	0.11	- -
Electric power[6]	**4.53**	**4.78**	**6.13**	**6.43**	**6.72**	**7.26**	**7.99**	**1.9%**
Conventional hydroelectric power	2.61	2.53	2.77	2.79	2.79	2.80	2.81	0.4%
Geothermal	0.15	0.16	0.26	0.37	0.50	0.60	0.67	5.5%
Biogenic municipal waste[7]	0.23	0.23	0.27	0.27	0.27	0.27	0.27	0.6%
Biomass	0.17	0.18	0.32	0.45	0.50	0.58	0.74	5.3%
Dedicated plants	0.10	0.12	0.14	0.16	0.18	0.21	0.32	3.8%
Cofiring	0.07	0.07	0.18	0.29	0.33	0.37	0.42	7.0%
Solar thermal	0.01	0.01	0.03	0.03	0.03	0.03	0.03	5.1%
Solar photovoltaic	0.03	0.08	0.28	0.29	0.31	0.36	0.45	6.8%
Wind	1.34	1.59	2.19	2.23	2.32	2.63	3.02	2.4%
Total marketed renewable energy	**8.50**	**8.95**	**10.42**	**10.76**	**11.04**	**11.60**	**12.52**	**1.3%**
Sources of ethanol								
from corn and other starch	1.08	1.09	1.10	1.09	1.10	1.11	1.19	0.3%
from cellulose	0.00	0.00	0.01	0.01	0.01	0.01	0.01	- -
Net imports	-0.02	-0.02	-0.03	-0.02	-0.03	-0.01	0.02	- -
Total	**1.06**	**1.07**	**1.09**	**1.08**	**1.08**	**1.12**	**1.23**	**0.5%**

Table A17. Renewable energy consumption by sector and source (continued)
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.04**	**0.06**	**0.13**	**0.17**	**0.23**	**0.28**	**0.35**	**7.0%**
Solar hot water heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.8%
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.03	0.03	0.03	4.1%
Solar photovoltaic	0.02	0.04	0.09	0.13	0.18	0.24	0.29	8.0%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	6.9%
Commercial	**0.13**	**0.14**	**0.17**	**0.20**	**0.25**	**0.32**	**0.39**	**3.9%**
Solar thermal	0.08	0.08	0.09	0.09	0.10	0.10	0.11	1.1%
Solar photovoltaic	0.04	0.05	0.08	0.11	0.15	0.20	0.27	6.1%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	9.0%

[1]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2. Actual heat rates used to determine fuel consumption for all renewable fuels except hydroelectric, geothermal, solar, and wind. Consumption at hydroelectric, geothermal, solar, and wind facilities is determined by using the fossil fuel equivalent of 9,516 Btu per kilowatthour.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Excludes motor gasoline component of E85.
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[6]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2013 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 ethanol: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2012 and 2013 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Petroleum	61	64	50	45	41	37	33	-2.4%
Natural gas	225	267	246	241	240	235	229	-0.6%
Electricity[1]	757	773	761	761	770	776	779	0.0%
Total residential	**1,044**	**1,105**	**1,057**	**1,047**	**1,051**	**1,048**	**1,042**	**-0.2%**
Commercial								
Petroleum	40	41	44	43	42	41	41	-0.1%
Natural gas	157	178	175	175	182	189	197	0.4%
Coal	4	4	5	5	5	5	4	0.5%
Electricity[1]	731	744	755	772	788	801	814	0.3%
Total commercial	**933**	**968**	**979**	**994**	**1,016**	**1,037**	**1,057**	**0.3%**
Industrial[2]								
Petroleum	345	350	410	425	424	424	429	0.8%
Natural gas[3]	447	462	512	523	539	549	563	0.7%
Coal	142	143	150	148	144	139	139	-0.1%
Electricity[1]	543	531	586	615	613	601	592	0.4%
Total industrial	**1,476**	**1,486**	**1,658**	**1,711**	**1,719**	**1,714**	**1,723**	**0.5%**
Transportation								
Petroleum[4]	1,774	1,792	1,752	1,701	1,662	1,647	1,631	-0.3%
Natural gas[5]	41	49	49	53	59	67	89	2.2%
Electricity[1]	4	4	5	5	6	8	9	2.9%
Total transportation	**1,819**	**1,845**	**1,806**	**1,759**	**1,727**	**1,722**	**1,728**	**-0.2%**
Electric power[6]								
Petroleum	19	23	13	13	13	13	13	-2.1%
Natural gas	493	442	412	441	478	497	509	0.5%
Coal	1,511	1,575	1,670	1,687	1,674	1,664	1,661	0.2%
Other[7]	12	12	12	12	12	12	12	0.0%
Total electric power	**2,035**	**2,053**	**2,107**	**2,153**	**2,177**	**2,186**	**2,195**	**0.2%**
Total by fuel								
Petroleum[4]	2,240	2,272	2,269	2,227	2,182	2,163	2,147	-0.2%
Natural gas	1,363	1,399	1,394	1,432	1,497	1,538	1,586	0.5%
Coal	1,657	1,722	1,824	1,840	1,822	1,808	1,804	0.2%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5,272**	**5,405**	**5,499**	**5,511**	**5,514**	**5,521**	**5,549**	**0.1%**
Carbon dioxide emissions (tons per person)	**16.8**	**17.1**	**16.5**	**15.9**	**15.4**	**14.9**	**14.6**	**-0.6%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2013, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
[6]Includes electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See Table A19, "Energy-Related Carbon Dioxide Emissions by End Use", for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.

Sources: 2012 and 2013 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Space heating	228	293	248	236	228	218	207	-1.3%
Space cooling	136	109	124	128	135	141	145	1.1%
Water heating	143	144	142	142	143	139	134	-0.3%
Refrigeration	60	59	53	51	51	51	52	-0.5%
Cooking	30	30	31	32	32	33	34	0.4%
Clothes dryers	35	36	36	37	37	38	39	0.3%
Freezers	13	13	11	11	10	10	9	-1.1%
Lighting	103	96	67	59	52	43	38	-3.3%
Clothes washers[1]	5	5	4	3	3	2	2	-2.4%
Dishwashers[1]	16	15	15	15	17	17	18	0.5%
Televisions and related equipment[2]	54	54	50	50	51	53	54	0.0%
Computers and related equipment[3]	20	20	15	12	11	9	7	-3.6%
Furnace fans and boiler circulation pumps	15	21	18	17	16	14	13	-1.8%
Other uses[4]	188	211	242	253	267	278	288	1.2%
Discrepancy[5]	0	0	0	0	0	0	0	- -
Total residential	**1,044**	**1,105**	**1,057**	**1,047**	**1,051**	**1,048**	**1,042**	**-0.2%**
Commercial								
Space heating[6]	112	136	122	115	111	105	97	-1.2%
Space cooling[6]	95	82	85	84	84	83	82	0.0%
Water heating[6]	44	45	44	44	44	44	43	-0.2%
Ventilation	82	84	85	85	85	84	83	0.0%
Cooking	14	14	15	15	16	16	16	0.4%
Lighting	149	148	137	131	127	120	116	-0.9%
Refrigeration	61	61	52	48	46	45	45	-1.1%
Office equipment (PC)	19	17	11	8	6	4	3	-5.9%
Office equipment (non-PC)	35	35	38	42	47	51	55	1.6%
Other uses[7]	321	346	392	422	452	484	516	1.5%
Total commercial	**933**	**968**	**979**	**994**	**1,016**	**1,037**	**1,057**	**0.3%**
Industrial[8]								
Manufacturing								
Refining	261	268	252	251	250	255	260	-0.1%
Food products	96	96	104	109	113	116	119	0.8%
Paper products	69	69	63	59	54	50	49	-1.2%
Bulk chemicals	247	247	293	311	309	298	291	0.6%
Glass	15	15	16	16	17	16	16	0.1%
Cement and lime	29	30	41	42	45	48	52	2.1%
Iron and steel	125	123	135	141	135	129	122	0.0%
Aluminum	45	46	54	55	51	43	38	-0.7%
Fabricated metal products	38	39	42	43	42	43	43	0.3%
Machinery	22	22	24	25	27	28	29	1.1%
Computers and electronics	47	48	48	49	51	53	52	0.3%
Transportation equipment	44	47	50	52	53	58	63	1.1%
Electrical equipment	8	8	9	10	10	11	12	1.4%
Wood products	15	17	20	20	20	19	18	0.3%
Plastics	39	40	44	46	48	49	49	0.8%
Balance of manufacturing	154	156	161	164	165	166	169	0.3%
Total manufacturing	**1,254**	**1,270**	**1,355**	**1,392**	**1,389**	**1,383**	**1,383**	**0.3%**
Nonmanufacturing								
Agriculture	66	66	65	64	62	60	58	-0.4%
Construction	62	64	77	80	83	85	87	1.1%
Mining	101	102	117	115	113	108	108	0.2%
Total nonmanufacturing	**230**	**232**	**259**	**259**	**257**	**253**	**253**	**0.3%**
Discrepancy[5]	-8	-16	44	61	73	79	86	- -
Total industrial	**1,476**	**1,486**	**1,658**	**1,711**	**1,719**	**1,714**	**1,723**	**0.5%**

Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

Sector and end use	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Transportation								
Light-duty vehicles	1,035	1,044	967	892	834	801	777	-1.1%
Commercial light trucks[9]	36	38	37	36	35	35	36	-0.2%
Bus transportation	16	18	18	18	19	19	19	0.2%
Freight trucks	356	389	417	429	440	456	477	0.8%
Rail, passenger	5	6	6	6	6	6	7	0.6%
Rail, freight	31	36	35	36	34	32	31	-0.5%
Shipping, domestic	7	7	7	6	6	5	5	-1.4%
Shipping, international	52	48	47	47	47	48	48	0.0%
Recreational boats	16	17	18	18	19	20	20	0.6%
Air	165	163	180	193	206	214	219	1.1%
Military use	50	48	45	45	48	51	54	0.5%
Lubricants	5	5	5	5	5	5	5	0.3%
Pipeline fuel	40	47	45	48	50	50	51	0.3%
Discrepancy[5]	5	-21	-21	-21	-21	-21	-20	- -
Total transportation	**1,819**	**1,845**	**1,806**	**1,759**	**1,727**	**1,722**	**1,728**	**-0.2%**
Biogenic energy combustion[10]								
Biomass	192	203	205	221	224	229	247	0.7%
Electric power sector	16	17	30	42	47	55	69	5.3%
Other sectors	176	186	175	179	177	174	178	-0.2%
Biogenic waste	21	21	24	25	24	24	24	0.6%
Biofuels heat and coproducts	69	68	75	75	75	76	81	0.6%
Ethanol	73	73	74	74	74	77	84	0.5%
Biodiesel	8	14	20	16	16	16	16	0.4%
Liquids from biomass	0	0	1	1	1	1	1	22.0%
Renewable diesel and gasoline	0	0	4	8	8	8	8	- -
Total	**362**	**379**	**403**	**419**	**422**	**431**	**461**	**0.7%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[6]Includes emissions related to fuel consumption for district services.
[7]Includes emissions related to (but not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[8]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[9]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[10]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A20. Macroeconomic indicators
(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Real gross domestic product	**15,369**	**15,710**	**18,801**	**21,295**	**23,894**	**26,659**	**29,898**	**2.4%**
Components of real gross domestic product								
Real consumption	10,450	10,700	12,832	14,484	16,275	18,179	20,476	2.4%
Real investment	2,436	2,556	3,531	4,025	4,474	4,984	5,634	3.0%
Real government spending	2,954	2,894	2,985	3,098	3,286	3,469	3,691	0.9%
Real exports	1,960	2,020	2,813	3,807	4,815	6,010	7,338	4.9%
Real imports	2,413	2,440	3,334	4,079	4,888	5,859	7,037	4.0%
Energy intensity (thousand Btu per 2009 dollar of GDP)								
Delivered energy	4.47	4.53	3.93	3.49	3.13	2.83	2.56	-2.1%
Total energy	6.14	6.18	5.36	4.79	4.31	3.90	3.54	-2.0%
Price indices								
GDP chain-type price index (2009=1.000)	1.05	1.07	1.21	1.31	1.43	1.57	1.73	1.8%
Consumer price index (1982-4=1.00)								
All-urban	2.30	2.33	2.63	2.89	3.18	3.54	3.95	2.0%
Energy commodities and services	2.46	2.44	2.55	2.98	3.42	4.03	4.85	2.6%
Wholesale price index (1982=1.00)								
All commodities	2.02	2.03	2.25	2.47	2.71	3.02	3.39	1.9%
Fuel and power	2.12	2.12	2.26	2.67	3.08	3.69	4.56	2.9%
Metals and metal products	2.20	2.14	2.43	2.62	2.85	3.13	3.42	1.8%
Industrial commodities excluding energy	1.94	1.96	2.22	2.40	2.61	2.85	3.12	1.7%
Interest rates (percent, nominal)								
Federal funds rate	0.14	0.11	3.40	3.56	3.69	3.76	4.04	- -
10-year treasury note	1.80	2.35	4.12	4.14	4.28	4.41	4.63	- -
AA utility bond rate	3.83	4.24	6.15	6.06	6.33	6.47	6.71	- -
Value of shipments (billion 2009 dollars)								
Non-industrial and service sectors	23,989	24,398	28,468	32,023	34,968	37,767	40,814	1.9%
Total industrial	6,822	7,004	8,467	9,212	9,870	10,614	11,463	1.8%
Agriculture, mining, and construction	1,813	1,858	2,344	2,441	2,540	2,601	2,712	1.4%
Manufacturing	5,009	5,146	6,123	6,771	7,330	8,012	8,751	2.0%
Energy-intensive	1,675	1,685	1,946	2,084	2,168	2,237	2,317	1.2%
Non-energy-intensive	3,334	3,461	4,177	4,687	5,162	5,776	6,433	2.3%
Total shipments	**30,810**	**31,402**	**36,935**	**41,235**	**44,838**	**48,380**	**52,277**	**1.9%**
Population and employment (millions)								
Population, with armed forces overseas	315	317	334	347	359	370	380	0.7%
Population, aged 16 and over	249	251	267	277	288	298	307	0.7%
Population, aged 65 and over	43	45	56	65	73	78	80	2.2%
Employment, nonfarm	134	136	149	154	159	163	169	0.8%
Employment, manufacturing	11.8	11.9	11.8	11.3	10.7	10.3	9.7	-0.7%
Key labor indicators								
Labor force (millions)	155	155	166	170	174	179	185	0.6%
Nonfarm labor productivity (2009=1.00)	1.05	1.05	1.20	1.34	1.48	1.62	1.78	2.0%
Unemployment rate (percent)	8.08	7.35	5.40	4.96	5.03	5.02	4.85	- -
Key indicators for energy demand								
Real disposable personal income	11,676	11,651	14,411	16,318	18,487	20,610	22,957	2.5%
Housing starts (millions)	0.84	0.99	1.69	1.70	1.66	1.62	1.62	1.8%
Commercial floorspace (billion square feet)	82.3	82.8	89.0	94.1	98.4	103.2	109.1	1.0%
Unit sales of light-duty vehicles (millions)	14.4	15.5	17.0	17.2	17.5	17.7	18.2	0.6%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2012 and 2013: IHS Economics, Industry and Employment models, November 2014. **Projections:** U.S. Energy Information Administration, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A21. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil spot prices								
(2013 dollars per barrel)								
Brent	113	109	79	91	106	122	141	1.0%
West Texas Intermediate	96	98	73	85	99	116	136	1.2%
(nominal dollars per barrel)								
Brent	112	109	90	112	142	180	229	2.8%
West Texas Intermediate	94	98	83	105	133	171	220	3.0%
Petroleum and other liquids consumption[1]								
OECD								
United States (50 states)	18.47	18.96	19.65	19.61	19.41	19.29	19.27	0.1%
United States territories	0.29	0.30	0.31	0.32	0.34	0.36	0.38	1.0%
Canada	2.29	2.29	2.31	2.25	2.21	2.17	2.14	-0.3%
Mexico and Chile	2.50	2.46	2.71	2.78	2.80	2.83	2.92	0.6%
OECD Europe[2]	14.07	13.96	14.20	14.15	14.09	14.03	14.12	0.0%
Japan	4.73	4.56	4.27	4.18	4.03	3.86	3.65	-0.8%
South Korea	2.41	2.43	2.58	2.57	2.53	2.46	2.40	0.0%
Australia and New Zealand	1.17	1.16	1.16	1.12	1.11	1.11	1.15	-0.1%
Total OECD consumption	**45.93**	**46.14**	**47.20**	**46.97**	**46.52**	**46.10**	**46.04**	**0.0%**
Non-OECD								
Russia	3.20	3.30	3.31	3.24	3.23	3.17	3.01	-0.3%
Other Europe and Eurasia[3]	2.00	2.06	2.22	2.28	2.39	2.50	2.59	0.9%
China	10.29	10.67	13.13	14.75	17.03	18.92	20.19	2.4%
India	3.63	3.70	4.30	4.89	5.52	6.13	6.79	2.3%
Other Asia[4]	7.35	7.37	9.08	10.69	12.35	14.20	16.49	3.0%
Middle East	7.32	7.61	8.40	8.81	9.56	10.28	11.13	1.4%
Africa	3.36	3.42	3.93	4.28	4.78	5.39	6.18	2.2%
Brazil	2.93	3.11	3.33	3.44	3.74	4.09	4.50	1.4%
Other Central and South America	3.35	3.38	3.49	3.55	3.72	3.90	4.15	0.8%
Total non-OECD consumption	**43.41**	**44.60**	**51.20**	**55.92**	**62.31**	**68.58**	**75.01**	**1.9%**
Total consumption	**89.3**	**90.7**	**98.4**	**102.9**	**108.8**	**114.7**	**121.0**	**1.1%**
Petroleum and other liquids production								
OPEC[5]								
Middle East	26.29	26.32	24.56	26.23	29.34	33.12	36.14	1.2%
North Africa	3.37	2.90	3.51	3.56	3.67	3.85	4.06	1.3%
West Africa	4.40	4.26	5.00	5.16	5.24	5.33	5.43	0.9%
South America	2.99	3.01	3.10	3.16	3.27	3.49	3.79	0.9%
Total OPEC production	**37.05**	**36.49**	**36.16**	**38.10**	**41.53**	**45.79**	**49.42**	**1.1%**
Non-OPEC								
OECD								
United States (50 states)	11.04	12.64	16.92	16.74	16.52	15.84	15.89	0.8%
Canada	4.00	4.15	5.05	5.68	6.26	6.61	6.76	1.8%
Mexico and Chile	2.96	2.94	2.93	3.12	3.32	3.52	3.79	0.9%
OECD Europe[2]	4.04	3.88	3.35	3.06	2.98	2.97	3.19	-0.7%
Japan and South Korea	0.18	0.18	0.17	0.17	0.18	0.18	0.18	0.1%
Australia and New Zealand	0.57	0.49	0.60	0.80	0.86	0.91	0.96	2.5%
Total OECD production	**22.80**	**24.29**	**29.03**	**29.58**	**30.12**	**30.03**	**30.77**	**0.9%**
Non-OECD								
Russia	10.52	10.50	10.71	10.78	11.22	11.81	12.16	0.5%
Other Europe and Eurasia[3]	3.20	3.27	3.41	4.14	4.42	4.70	5.18	1.7%
China	4.39	4.48	5.11	5.46	5.66	5.75	5.84	1.0%
Other Asia[4]	3.88	3.82	3.85	3.72	3.67	3.71	4.01	0.2%
Middle East	1.31	1.20	1.03	0.93	0.85	0.78	0.77	-1.6%
Africa	2.31	2.41	2.70	2.86	2.94	3.03	3.33	1.2%
Brazil	2.61	2.73	3.70	4.56	5.43	5.90	6.12	3.0%
Other Central and South America	2.17	2.21	2.71	2.76	2.97	3.16	3.47	1.7%
Total non-OECD production	**30.38**	**30.63**	**33.21**	**35.22**	**37.17**	**38.85**	**40.88**	**1.1%**
Total petroleum and other liquids production	**90.2**	**91.4**	**98.4**	**102.9**	**108.8**	**114.7**	**121.1**	**1.0%**
OPEC market share (percent)	41.1	39.9	36.7	37.0	38.2	39.9	40.8	- -

Table A21. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Selected world production subtotals:								
Crude oil and equivalents[6]	77.35	77.93	82.19	85.20	89.77	94.33	99.09	0.9%
Tight oil	2.63	3.62	7.49	8.31	9.16	9.82	10.15	3.9%
Bitumen[7]	1.94	2.11	3.00	3.52	3.95	4.21	4.26	2.6%
Refinery processing gain[8]	2.37	2.40	2.42	2.61	2.74	2.88	2.97	0.8%
Natural gas plant liquids	9.11	9.36	11.28	11.93	12.42	12.93	13.79	1.4%
Liquids from renewable sources[9]	1.93	2.14	2.56	2.92	3.36	3.78	4.22	2.5%
Liquids from coal[10]	0.21	0.21	0.33	0.51	0.69	0.87	1.05	6.2%
Liquids from natural gas[11]	0.14	0.24	0.33	0.43	0.51	0.57	0.61	3.5%
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.7%
Crude oil production[6]								
OPEC[5]								
Middle East	23.24	23.13	21.20	22.66	25.59	29.11	31.79	1.2%
North Africa	2.91	2.43	2.93	2.93	2.92	2.93	2.96	0.7%
West Africa	4.34	4.20	4.89	5.05	5.13	5.21	5.29	0.9%
South America	2.80	2.82	2.86	2.86	2.98	3.20	3.48	0.8%
Total OPEC production	**33.30**	**32.60**	**31.89**	**33.51**	**36.62**	**40.46**	**43.52**	**1.1%**
Non-OPEC								
OECD								
United States (50 states)	7.54	8.90	11.58	11.28	11.01	10.37	10.41	0.6%
Canada	3.28	3.42	4.35	4.93	5.48	5.83	5.92	2.0%
Mexico and Chile	2.61	2.59	2.61	2.81	3.00	3.22	3.45	1.1%
OECD Europe[2]	2.99	2.82	2.17	1.80	1.66	1.58	1.69	-1.9%
Japan and South Korea	0.01	0.00	0.00	0.00	0.00	0.00	0.00	-1.6%
Australia and New Zealand	0.45	0.37	0.47	0.61	0.67	0.71	0.75	2.7%
Total OECD production	**16.87**	**18.10**	**21.18**	**21.44**	**21.83**	**21.71**	**22.23**	**0.8%**
Non-OECD								
Russia	10.04	10.02	10.15	10.11	10.42	10.85	11.10	0.4%
Other Europe and Eurasia[3]	2.95	3.05	3.18	3.83	4.03	4.21	4.66	1.6%
China	4.07	4.16	4.54	4.68	4.56	4.36	4.13	0.0%
Other Asia[4]	3.14	3.04	2.94	2.63	2.45	2.38	2.47	-0.8%
Middle East	1.26	1.16	1.00	0.90	0.82	0.76	0.74	-1.6%
Africa	1.88	1.97	2.18	2.31	2.38	2.45	2.70	1.2%
Brazil	2.06	2.02	2.87	3.50	4.16	4.47	4.60	3.1%
Other Central and South America	1.77	1.81	2.25	2.29	2.49	2.67	2.94	1.8%
Total non-OECD production	**27.18**	**27.24**	**29.11**	**30.25**	**31.32**	**32.15**	**33.35**	**0.8%**
Total crude oil production[6]	**77.3**	**77.9**	**82.2**	**85.2**	**89.8**	**94.3**	**99.1**	**0.9%**
OPEC market share (percent)	43.1	41.8	38.8	39.3	40.8	42.9	43.9	- -

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2012 quantities derived from: Energy Information Administration (EIA), International Energy Statistics database as of September 2014. **2013 quantities and projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A and EIA, Generate World Oil Balance application.

Economic growth case comparisons

Table B1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	15.6	22.2	22.2	22.2	20.8	21.1	21.3	19.4	19.9	20.3
Natural gas plant liquids	3.6	5.4	5.5	5.5	5.6	5.7	5.8	5.4	5.5	5.7
Dry natural gas	25.1	29.2	29.6	30.0	32.6	33.9	35.3	35.5	36.4	37.7
Coal[1]	20.0	20.8	21.7	22.0	21.8	22.5	23.0	21.7	22.6	23.5
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.6	8.5	8.7	9.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[3]	4.2	4.5	4.4	4.5	4.4	4.6	5.0	4.5	5.0	6.0
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.2	3.7	4.6	6.7
Other[5]	1.3	0.8	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.0
Total	**82.7**	**97.4**	**98.7**	**99.7**	**100.7**	**103.7**	**107.0**	**102.3**	**106.6**	**113.3**
Imports										
Crude oil	17.0	12.8	13.6	14.3	13.9	15.7	17.3	15.6	18.2	20.7
Petroleum and other liquids[6]	4.3	4.5	4.6	4.6	4.3	4.4	4.5	4.0	4.1	4.6
Natural gas[7]	2.9	1.8	1.9	2.0	1.4	1.6	1.7	1.6	1.7	1.9
Other imports[8]	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**24.5**	**19.3**	**20.2**	**21.0**	**19.7**	**21.7**	**23.5**	**21.3**	**24.1**	**27.3**
Exports										
Petroleum and other liquids[9]	7.3	11.1	11.2	11.1	12.7	12.6	12.6	13.7	13.7	13.7
Natural gas[10]	1.6	4.5	4.5	4.1	6.8	6.4	5.9	8.1	7.4	6.7
Coal	2.9	2.5	2.5	2.5	3.3	3.3	3.3	3.5	3.5	3.5
Total	**11.7**	**18.1**	**18.1**	**17.7**	**22.8**	**22.4**	**21.7**	**25.3**	**24.6**	**23.9**
Discrepancy[11]	**-1.6**	**-0.1**	**-0.1**	**-0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**
Consumption										
Petroleum and other liquids[12]	35.9	36.2	37.1	37.9	34.1	36.5	38.5	32.9	36.2	39.8
Natural gas	26.9	26.4	26.8	27.7	27.0	28.8	30.9	28.6	30.5	32.7
Coal[13]	18.0	18.3	19.2	19.5	18.4	19.2	19.6	18.1	19.0	19.9
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.6	8.5	8.7	9.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[14]	2.9	3.0	3.0	3.1	2.9	3.2	3.6	3.1	3.5	4.4
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.2	3.7	4.6	6.7
Other[15]	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Total	**97.1**	**98.7**	**100.8**	**103.1**	**97.5**	**102.9**	**108.5**	**98.0**	**105.7**	**116.2**
Prices (2013 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	78	79	80	104	106	108	138	141	145
West Texas Intermediate	98	72	73	74	97	99	102	132	136	140
Natural gas at Henry Hub (dollars per million Btu)	3.73	4.53	4.88	5.03	5.43	5.69	6.02	7.46	7.85	8.45
Coal (dollars per ton) at the minemouth[16]	37.2	37.5	37.9	38.0	43.6	43.7	44.1	49.0	49.2	50.3
Coal (dollars per million Btu) at the minemouth[16]	1.84	1.86	1.88	1.89	2.17	2.18	2.20	2.43	2.44	2.49
Average end-use[17]	2.50	2.50	2.54	2.56	2.81	2.84	2.88	3.06	3.09	3.18
Average electricity (cents per kilowatthour)	10.1	10.3	10.5	10.6	10.7	11.1	11.1	11.4	11.8	12.3

Table B1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	95	90	90	178	142	139	345	229	224
West Texas Intermediate	98	87	83	83	168	133	132	331	220	216
Natural gas at Henry Hub										
(dollars per million Btu)	3.73	5.47	5.54	5.68	9.36	7.63	7.77	18.71	12.73	13.03
Coal (dollars per ton)										
at the minemouth[16]	37.2	45.2	43.0	42.8	75.0	58.6	57.0	122.9	79.8	77.6
Coal (dollars per million Btu)										
at the minemouth[16]	1.84	2.25	2.14	2.13	3.73	2.92	2.84	6.09	3.96	3.85
Average end-use[17]	2.50	3.02	2.88	2.89	4.84	3.81	3.71	7.67	5.00	4.90
Average electricity (cents per kilowatthour)	10.1	12.4	11.9	11.9	18.4	14.8	14.4	28.6	19.2	18.9

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2013 coal values: *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2013 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

Table B2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Energy consumption										
Residential										
Propane	0.43	0.32	0.32	0.33	0.27	0.28	0.30	0.23	0.25	0.28
Kerosene	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00
Distillate fuel oil	0.50	0.40	0.40	0.40	0.31	0.31	0.31	0.24	0.24	0.24
Petroleum and other liquids subtotal	0.93	0.73	0.73	0.74	0.58	0.59	0.62	0.47	0.49	0.53
Natural gas	5.05	4.59	4.63	4.70	4.32	4.52	4.76	3.98	4.31	4.67
Renewable energy[1]	0.58	0.41	0.41	0.42	0.36	0.38	0.39	0.34	0.35	0.37
Electricity	4.75	4.77	4.86	5.00	4.82	5.08	5.50	4.96	5.42	6.07
Delivered energy	**11.32**	**10.50**	**10.63**	**10.85**	**10.09**	**10.57**	**11.26**	**9.74**	**10.57**	**11.64**
Electricity related losses	9.79	9.57	9.75	9.97	9.56	9.91	10.52	9.60	10.33	11.51
Total	**21.10**	**20.07**	**20.38**	**20.82**	**19.66**	**20.48**	**21.78**	**19.35**	**20.91**	**23.15**
Commercial										
Propane	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.37	0.34	0.34	0.34	0.31	0.30	0.30	0.27	0.27	0.27
Residual fuel oil	0.03	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.07
Petroleum and other liquids subtotal	0.59	0.62	0.62	0.62	0.60	0.60	0.60	0.57	0.58	0.59
Natural gas	3.37	3.32	3.30	3.29	3.38	3.43	3.45	3.62	3.71	3.75
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.57	4.82	4.82	4.83	5.17	5.19	5.27	5.59	5.66	5.77
Delivered energy	**8.69**	**8.92**	**8.90**	**8.91**	**9.31**	**9.38**	**9.48**	**9.95**	**10.12**	**10.27**
Electricity related losses	9.42	9.66	9.68	9.64	10.24	10.13	10.07	10.83	10.80	10.93
Total	**18.10**	**18.58**	**18.58**	**18.55**	**19.55**	**19.52**	**19.56**	**20.78**	**20.92**	**21.20**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.51	3.13	3.20	3.23	3.51	3.72	3.81	3.60	3.67	3.76
Motor gasoline[2]	0.25	0.25	0.26	0.27	0.24	0.25	0.27	0.23	0.25	0.26
Distillate fuel oil	1.31	1.33	1.42	1.46	1.24	1.36	1.49	1.21	1.35	1.51
Residual fuel oil	0.06	0.11	0.10	0.13	0.12	0.13	0.14	0.11	0.13	0.15
Petrochemical feedstocks	0.74	0.94	0.95	0.98	1.07	1.14	1.17	1.16	1.20	1.23
Other petroleum[6]	3.52	3.53	3.67	3.90	3.42	3.83	4.20	3.44	3.99	4.56
Petroleum and other liquids subtotal	8.40	9.30	9.61	9.96	9.59	10.44	11.08	9.76	10.59	11.48
Natural gas	7.62	8.04	8.33	8.46	8.04	8.65	9.17	8.13	8.90	9.83
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.85	1.87	1.85	2.09	2.10	2.12	2.29	2.29	2.33
Natural gas subtotal	9.14	9.89	10.20	10.31	10.12	10.75	11.29	10.42	11.19	12.15
Metallurgical coal	0.62	0.55	0.61	0.65	0.49	0.56	0.66	0.43	0.51	0.69
Other industrial coal	0.88	0.89	0.93	1.00	0.87	0.96	1.09	0.87	0.99	1.25
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.48	1.44	1.54	1.65	1.33	1.48	1.72	1.25	1.44	1.86
Biofuels heat and coproducts	0.72	0.80	0.80	0.81	0.80	0.80	0.81	0.80	0.86	0.89
Renewable energy[8]	1.48	1.47	1.53	1.64	1.37	1.59	1.87	1.34	1.63	2.23
Electricity	3.26	3.58	3.74	3.99	3.58	4.04	4.49	3.60	4.12	4.88
Delivered energy	**24.48**	**26.48**	**27.42**	**28.35**	**26.80**	**29.10**	**31.27**	**27.17**	**29.82**	**33.50**
Electricity related losses	6.72	7.17	7.51	7.95	7.11	7.88	8.59	6.96	7.85	9.26
Total	**31.20**	**33.65**	**34.93**	**36.30**	**33.91**	**36.98**	**39.86**	**34.13**	**37.68**	**42.76**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Transportation										
Propane	0.05	0.04	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.08
Motor gasoline[2]	15.94	15.26	15.35	15.42	12.75	13.30	13.57	11.28	12.55	13.19
of which: E85[9]	0.02	0.03	0.03	0.03	0.26	0.20	0.19	0.29	0.28	0.30
Jet fuel[10]	2.80	2.95	3.01	3.07	3.27	3.40	3.54	3.51	3.64	3.79
Distillate fuel oil[11]	6.50	6.91	7.35	7.77	6.93	7.76	8.79	6.88	7.97	10.01
Residual fuel oil	0.57	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.37
Other petroleum[12]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Petroleum and other liquids subtotal	26.00	25.68	26.27	26.82	23.52	25.03	26.48	22.25	24.76	27.61
Pipeline fuel natural gas	0.88	0.84	0.85	0.87	0.91	0.94	0.98	0.93	0.96	1.00
Compressed / liquefied natural gas	0.05	0.06	0.07	0.06	0.16	0.17	0.16	0.68	0.71	0.89
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.06	0.06	0.06
Delivered energy	**26.96**	**26.61**	**27.22**	**27.79**	**24.63**	**26.18**	**27.67**	**23.93**	**26.49**	**29.57**
Electricity related losses	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.11	0.12	0.12
Total	**27.01**	**26.67**	**27.29**	**27.85**	**24.71**	**26.27**	**27.75**	**24.04**	**26.61**	**29.69**
Unspecified sector[13]	**-0.27**	**-0.30**	**-0.34**	**-0.37**	**-0.31**	**-0.37**	**-0.45**	**-0.30**	**-0.38**	**-0.55**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	3.14	3.66	3.73	3.76	4.00	4.23	4.35	4.06	4.17	4.31
Motor gasoline[2]	16.36	15.69	15.79	15.86	13.15	13.72	14.00	11.66	12.96	13.62
of which: E85[9]	0.02	0.03	0.03	0.03	0.26	0.20	0.19	0.29	0.28	0.30
Jet fuel[10]	2.97	3.13	3.20	3.26	3.47	3.61	3.75	3.73	3.86	4.03
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.10	8.37	8.86	9.28	8.17	9.05	10.11	7.99	9.13	11.15
Residual fuel oil	0.65	0.53	0.53	0.55	0.54	0.56	0.57	0.54	0.56	0.58
Petrochemical feedstocks	0.74	0.94	0.95	0.98	1.07	1.14	1.17	1.16	1.20	1.23
Other petroleum[14]	3.67	3.68	3.82	4.06	3.57	3.98	4.36	3.59	4.15	4.72
Petroleum and other liquids subtotal	35.65	36.02	36.89	37.77	33.98	36.30	38.33	32.75	36.03	39.65
Natural gas	16.10	16.01	16.32	16.51	15.89	16.76	17.54	16.42	17.64	19.14
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.85	1.87	1.85	2.09	2.10	2.12	2.29	2.29	2.33
Pipeline natural gas	0.88	0.84	0.85	0.87	0.91	0.94	0.98	0.93	0.96	1.00
Natural gas subtotal	18.50	18.70	19.05	19.23	18.89	19.80	20.64	19.64	20.88	22.47
Metallurgical coal	0.62	0.55	0.61	0.65	0.49	0.56	0.66	0.43	0.51	0.69
Other coal	0.92	0.94	0.98	1.04	0.91	1.00	1.14	0.92	1.04	1.30
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.52	1.49	1.59	1.69	1.38	1.53	1.77	1.30	1.49	1.91
Biofuels heat and coproducts	0.72	0.80	0.80	0.81	0.80	0.80	0.81	0.80	0.86	0.89
Renewable energy[15]	2.18	2.00	2.06	2.17	1.85	2.09	2.38	1.80	2.10	2.72
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.60	13.20	13.45	13.85	13.61	14.35	15.30	14.20	15.25	16.78
Delivered energy	**71.17**	**72.21**	**73.84**	**75.52**	**70.52**	**74.87**	**79.23**	**70.49**	**76.62**	**84.44**
Electricity related losses	25.97	26.45	27.00	27.62	26.99	28.01	29.27	27.51	29.10	31.81
Total	**97.14**	**98.67**	**100.84**	**103.15**	**97.52**	**102.87**	**108.50**	**97.99**	**105.73**	**116.25**
Electric power[16]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.08	0.08	0.09	0.08	0.08	0.08
Residual fuel oil	0.21	0.08	0.08	0.09	0.08	0.09	0.09	0.09	0.09	0.10
Petroleum and other liquids subtotal	0.26	0.17	0.17	0.18	0.17	0.17	0.18	0.17	0.18	0.18
Natural gas	8.36	7.66	7.80	8.42	8.14	9.03	10.24	8.97	9.61	10.23
Steam coal	16.49	16.84	17.59	17.85	17.00	17.63	17.85	16.81	17.52	17.95
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.57	8.46	8.73	9.54
Renewable energy[18]	4.78	6.23	6.13	6.26	6.53	6.72	7.41	6.97	7.99	10.33
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.09	0.10	0.10	0.11	0.11	0.13
Total	**38.57**	**39.65**	**40.45**	**41.47**	**40.61**	**42.35**	**44.57**	**41.71**	**44.36**	**48.59**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Total energy consumption										
Liquefied petroleum gases and other[5]	3.14	3.66	3.73	3.76	4.00	4.23	4.35	4.06	4.17	4.31
Motor gasoline[2]	16.36	15.69	15.79	15.86	13.15	13.72	14.00	11.66	12.96	13.62
of which: E85[9]	0.02	0.03	0.03	0.03	0.26	0.20	0.19	0.29	0.28	0.30
Jet fuel[10]	2.97	3.13	3.20	3.26	3.47	3.61	3.75	3.73	3.86	4.03
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.15	8.46	8.95	9.37	8.25	9.13	10.20	8.07	9.21	11.23
Residual fuel oil	0.87	0.62	0.61	0.64	0.63	0.64	0.66	0.63	0.65	0.68
Petrochemical feedstocks	0.74	0.94	0.95	0.98	1.07	1.14	1.17	1.16	1.20	1.23
Other petroleum[14]	3.67	3.68	3.82	4.06	3.57	3.98	4.36	3.59	4.15	4.72
Petroleum and other liquids subtotal	35.91	36.19	37.06	37.95	34.15	36.47	38.50	32.92	36.21	39.84
Natural gas	24.46	23.67	24.12	24.93	24.03	25.79	27.77	25.39	27.25	29.37
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.85	1.87	1.85	2.09	2.10	2.12	2.29	2.29	2.33
Pipeline natural gas	0.88	0.84	0.85	0.87	0.91	0.94	0.98	0.93	0.96	1.00
Natural gas subtotal	26.86	26.36	26.85	27.65	27.03	28.83	30.88	28.61	30.50	32.70
Metallurgical coal	0.62	0.55	0.61	0.65	0.49	0.56	0.66	0.43	0.51	0.69
Other coal	17.41	17.78	18.57	18.90	17.91	18.63	18.99	17.72	18.56	19.25
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	18.01	18.32	19.18	19.55	18.37	19.16	19.61	18.10	19.01	19.87
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.57	8.46	8.73	9.54
Biofuels heat and coproducts	0.72	0.80	0.80	0.81	0.80	0.80	0.81	0.80	0.86	0.89
Renewable energy[19]	6.96	8.23	8.19	8.44	8.38	8.81	9.79	8.77	10.09	13.05
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.09	0.10	0.10	0.11	0.11	0.13
Total	**97.14**	**98.67**	**100.84**	**103.15**	**97.52**	**102.87**	**108.50**	**97.99**	**105.73**	**116.25**
Energy use and related statistics										
Delivered energy use	71.17	72.21	73.84	75.52	70.52	74.87	79.23	70.49	76.62	84.44
Total energy use	97.14	98.67	100.84	103.15	97.52	102.87	108.50	97.99	105.73	116.25
Ethanol consumed in motor gasoline and E85	1.12	1.12	1.12	1.13	1.12	1.12	1.14	1.16	1.27	1.34
Population (millions)	317	333	334	335	354	359	363	371	380	390
Gross domestic product (billion 2009 dollars)	15,710	17,747	18,801	19,590	21,224	23,894	26,146	25,763	29,898	34,146
Carbon dioxide emissions (million metric tons)	5,405	5,343	5,499	5,631	5,210	5,514	5,791	5,160	5,549	5,979

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

Table B3. Energy prices by sector and source

(2013 dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	23.3	22.8	23.0	23.1	24.2	24.4	24.6	26.4	26.6	26.9
Distillate fuel oil	27.2	21.2	21.5	21.7	25.5	26.3	26.9	31.8	32.9	34.2
Natural gas	10.0	11.1	11.6	11.9	12.5	12.8	13.4	14.7	15.5	16.6
Electricity	35.6	37.1	37.8	38.0	38.7	40.0	40.1	41.2	42.4	43.7
Commercial										
Propane	20.0	19.2	19.4	19.5	20.9	21.1	21.3	23.7	23.9	24.3
Distillate fuel oil	26.7	20.6	21.0	21.1	25.1	25.8	26.4	31.3	32.5	33.9
Residual fuel oil	22.1	14.1	14.2	14.3	17.8	18.1	18.4	24.0	24.3	24.0
Natural gas	8.1	9.1	9.6	9.8	10.3	10.4	10.8	12.1	12.6	13.4
Electricity	29.7	30.2	31.1	31.6	31.2	32.6	33.1	33.0	34.5	36.3
Industrial[1]										
Propane	20.3	19.4	19.6	19.8	21.2	21.5	21.7	24.2	24.5	24.9
Distillate fuel oil	27.3	20.9	21.2	21.4	25.5	26.1	26.7	31.6	32.7	34.2
Residual fuel oil	20.0	13.2	13.3	13.4	16.9	17.2	17.6	23.1	23.5	23.1
Natural gas[2]	4.6	5.7	6.2	6.4	6.6	6.8	7.1	8.4	8.8	9.2
Metallurgical coal	5.5	5.8	5.8	5.8	6.7	6.7	6.7	7.1	7.2	7.3
Other industrial coal	3.2	3.3	3.3	3.3	3.6	3.6	3.6	3.9	3.9	4.0
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.2	20.7	21.3	21.6	21.6	22.6	23.1	23.5	24.7	26.0
Transportation										
Propane	24.6	23.8	24.0	24.1	25.2	25.5	25.6	27.4	27.6	27.9
E85[3]	33.1	30.1	30.4	30.7	28.7	31.2	31.5	33.9	35.4	36.9
Motor gasoline[4]	29.3	22.3	22.5	22.6	25.8	26.4	26.7	31.3	32.3	33.5
Jet fuel[5]	21.8	15.8	16.1	16.3	20.7	21.3	22.0	27.4	28.3	29.7
Diesel fuel (distillate fuel oil)[6]	28.2	22.8	23.1	23.3	27.4	28.0	28.6	33.5	34.7	36.2
Residual fuel oil	19.3	11.4	11.7	11.9	15.0	15.4	15.8	19.8	20.3	21.0
Natural gas[7]	17.6	17.2	17.8	18.2	15.3	15.7	16.5	18.6	19.6	20.7
Electricity	28.5	29.3	30.2	31.0	31.5	32.9	33.2	34.5	36.0	37.7
Electric power[8]										
Distillate fuel oil	24.0	18.5	18.8	18.9	22.8	23.6	24.2	29.1	30.2	31.6
Residual fuel oil	18.9	11.3	11.5	11.5	15.0	15.4	15.7	21.3	21.6	21.3
Natural gas	4.4	4.9	5.4	5.6	6.0	6.2	6.6	7.9	8.3	8.7
Steam coal	2.3	2.3	2.4	2.4	2.7	2.7	2.7	2.9	2.9	3.0
Average price to all users[9]										
Propane	21.9	20.8	21.1	21.2	22.3	22.6	22.8	24.9	25.2	25.6
E85[3]	33.1	30.1	30.4	30.7	28.7	31.2	31.5	33.9	35.4	36.9
Motor gasoline[4]	29.0	22.3	22.5	22.6	25.8	26.4	26.7	31.3	32.3	33.5
Jet fuel[5]	21.8	15.8	16.1	16.3	20.7	21.3	22.0	27.4	28.3	29.7
Distillate fuel oil	27.9	22.3	22.6	22.8	26.9	27.6	28.2	33.1	34.2	35.8
Residual fuel oil	19.4	12.0	12.2	12.4	15.6	16.0	16.5	21.1	21.5	21.8
Natural gas	6.1	7.0	7.5	7.6	8.0	8.2	8.5	10.0	10.5	11.1
Metallurgical coal	5.5	5.8	5.8	5.8	6.7	6.7	6.7	7.1	7.2	7.3
Other coal	2.4	2.4	2.4	2.4	2.7	2.7	2.7	3.0	3.0	3.0
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	29.5	30.1	30.8	31.0	31.4	32.4	32.7	33.5	34.7	36.0
Non-renewable energy expenditures by sector (billion 2013 dollars)										
Residential	243	244	254	262	255	276	300	277	311	358
Commercial	177	188	194	197	210	219	226	245	259	277
Industrial[1]	224	247	264	279	286	323	356	344	389	454
Transportation	719	546	565	579	584	638	687	687	791	922
Total non-renewable expenditures	1,364	1,225	1,276	1,317	1,336	1,456	1,569	1,553	1,751	2,011
Transportation renewable expenditures	1	1	1	1	8	6	6	10	10	11
Total expenditures	**1,364**	**1,226**	**1,277**	**1,318**	**1,344**	**1,462**	**1,575**	**1,562**	**1,761**	**2,023**

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	23.3	27.6	26.1	26.1	41.7	32.8	31.8	66.3	43.1	41.5
Distillate fuel oil	27.2	25.6	24.4	24.5	44.0	35.3	34.8	79.7	53.3	52.8
Natural gas	10.0	13.4	13.2	13.4	21.6	17.1	17.2	36.9	25.1	25.6
Electricity	35.6	44.8	42.9	42.8	66.7	53.6	51.8	103.4	68.8	67.4
Commercial										
Propane	20.0	23.1	22.0	22.0	36.0	28.3	27.6	59.4	38.8	37.5
Distillate fuel oil	26.7	24.9	23.8	23.8	43.3	34.6	34.1	78.6	52.6	52.3
Residual fuel oil	22.1	17.0	16.1	16.1	30.6	24.3	23.8	60.3	39.4	37.0
Natural gas	8.1	11.0	10.8	11.1	17.7	13.9	14.0	30.4	20.5	20.7
Electricity	29.7	36.5	35.3	35.6	53.8	43.7	42.8	82.8	56.0	56.0
Industrial[1]										
Propane	20.3	23.4	22.3	22.3	36.6	28.8	28.1	60.7	39.7	38.4
Distillate fuel oil	27.3	25.2	24.1	24.1	43.8	35.0	34.5	79.3	53.0	52.7
Residual fuel oil	20.0	15.9	15.1	15.2	29.1	23.1	22.7	58.0	38.0	35.7
Natural gas[2]	4.6	6.9	7.0	7.2	11.4	9.1	9.2	21.0	14.2	14.2
Metallurgical coal	5.5	7.0	6.6	6.5	11.5	8.9	8.6	17.9	11.6	11.2
Other industrial coal	3.2	4.0	3.8	3.8	6.2	4.8	4.7	9.7	6.3	6.1
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.2	24.9	24.2	24.3	37.2	30.3	29.8	58.9	40.0	40.2
Transportation										
Propane	24.6	28.8	27.2	27.2	43.5	34.1	33.1	68.8	44.8	43.1
E85[3]	33.1	36.3	34.4	34.7	49.5	41.9	40.7	85.1	57.4	56.9
Motor gasoline[4]	29.3	27.0	25.5	25.5	44.5	35.3	34.5	78.4	52.4	51.7
Jet fuel[5]	21.8	19.1	18.3	18.3	35.6	28.6	28.4	68.7	45.8	45.9
Diesel fuel (distillate fuel oil)[6]	28.2	27.5	26.2	26.3	47.2	37.6	37.0	84.1	56.2	55.9
Residual fuel oil	19.3	13.8	13.2	13.4	25.7	20.6	20.5	49.8	32.9	32.4
Natural gas[7]	17.6	20.7	20.2	20.6	26.3	21.0	21.3	46.7	31.8	31.9
Electricity	28.5	35.4	34.3	35.0	54.3	44.1	42.8	86.6	58.4	58.1
Electric power[8]										
Distillate fuel oil	24.0	22.3	21.3	21.4	39.3	31.7	31.3	72.9	49.0	48.7
Residual fuel oil	18.9	13.7	13.0	13.0	25.9	20.6	20.3	53.4	35.0	32.8
Natural gas	4.4	6.0	6.1	6.4	10.4	8.3	8.5	19.8	13.4	13.4
Steam coal	2.3	2.8	2.7	2.7	4.6	3.6	3.5	7.3	4.7	4.6

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	2020 Low economic growth	2020 Reference	2020 High economic growth	2030 Low economic growth	2030 Reference	2030 High economic growth	2040 Low economic growth	2040 Reference	2040 High economic growth
Average price to all users[9]										
Propane	21.9	25.1	23.9	23.9	38.4	30.3	29.5	62.4	40.9	39.5
E85[3]	33.1	36.3	34.4	34.7	49.5	41.9	40.7	85.1	57.4	56.9
Motor gasoline[4]	29.0	27.0	25.5	25.5	44.5	35.3	34.5	78.4	52.4	51.7
Jet fuel[5]	21.8	19.1	18.3	18.3	35.6	28.6	28.4	68.7	45.8	45.9
Distillate fuel oil	27.9	26.9	25.7	25.7	46.4	36.9	36.4	83.0	55.5	55.2
Residual fuel oil	19.4	14.5	13.8	14.0	26.9	21.5	21.3	52.8	34.8	33.6
Natural gas	6.1	8.5	8.5	8.6	13.9	11.0	11.0	25.1	17.0	17.1
Metallurgical coal	5.5	7.0	6.6	6.5	11.5	8.9	8.6	17.9	11.6	11.2
Other coal	2.4	2.9	2.8	2.8	4.7	3.7	3.5	7.4	4.8	4.7
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	29.5	36.4	34.9	35.0	54.0	43.4	42.2	83.9	56.2	55.5
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	243	295	288	296	440	370	387	694	504	553
Commercial	177	227	220	223	362	294	292	614	420	428
Industrial[1]	224	298	299	314	493	433	460	863	631	700
Transportation	719	660	641	654	1,006	855	888	1,724	1,283	1,422
Total non-renewable expenditures	1,364	1,479	1,448	1,487	2,301	1,952	2,027	3,894	2,839	3,103
Transportation renewable expenditures	1	1	1	1	13	8	8	24	16	17
Total expenditures	**1,364**	**1,480**	**1,449**	**1,488**	**2,314**	**1,960**	**2,035**	**3,919**	**2,855**	**3,120**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 transportation sector natural gas delivered prices are model results. 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

Table B4. Macroeconomic indicators
(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Real gross domestic product	**15,710**	**17,747**	**18,801**	**19,590**	**21,224**	**23,894**	**26,146**	**25,763**	**29,898**	**34,146**
Components of real gross domestic product										
Real consumption	10,700	12,214	12,832	13,285	14,388	16,275	17,804	17,094	20,476	22,973
Real investment	2,556	3,157	3,531	3,923	3,828	4,474	5,146	4,685	5,634	6,720
Real government spending	2,894	2,926	2,985	3,039	3,130	3,286	3,423	3,441	3,691	3,943
Real exports	2,020	2,623	2,813	2,935	4,039	4,815	5,395	5,818	7,338	9,163
Real imports	2,440	3,158	3,334	3,563	4,142	4,888	5,535	5,152	7,037	8,334
Energy intensity (thousand Btu per 2009 dollar of GDP)										
Delivered energy	4.53	4.07	3.93	3.86	3.32	3.13	3.03	2.74	2.56	2.47
Total energy	6.18	5.56	5.36	5.27	4.59	4.31	4.15	3.80	3.54	3.40
Price indices										
GDP chain-type price index (2009=1.000)	1.07	1.29	1.21	1.20	1.84	1.43	1.38	2.68	1.73	1.65
Consumer price index (1982-4=1.00)										
All-urban	2.33	2.79	2.63	2.62	4.06	3.18	3.06	6.08	3.95	3.77
Energy commodities and services	2.44	2.67	2.55	2.56	4.28	3.42	3.35	7.26	4.85	4.82
Wholesale price index (1982=1.00)										
All commodities	2.03	2.38	2.25	2.27	3.46	2.71	2.64	5.21	3.39	3.32
Fuel and power	2.12	2.34	2.26	2.28	3.84	3.08	3.03	6.84	4.56	4.56
Metals and metal products	2.14	2.55	2.43	2.54	3.54	2.85	2.89	4.96	3.42	3.59
Industrial commodities excluding energy	1.96	2.36	2.22	2.24	3.36	2.61	2.54	4.81	3.12	3.04
Interest rates (percent, nominal)										
Federal funds rate	0.11	5.28	3.40	3.07	6.92	3.69	3.60	7.72	4.04	3.89
10-year treasury note	2.35	5.29	4.12	3.87	6.60	4.28	4.16	7.52	4.63	4.53
AA utility bond rate	4.24	7.73	6.15	5.35	9.23	6.33	5.59	10.34	6.71	5.69
Value of shipments (billion 2009 dollars)										
Non-industrial and service sectors	24,398	27,029	28,468	29,598	31,111	34,968	38,353	34,777	40,814	46,610
Total industrial	7,004	7,848	8,467	8,967	8,608	9,870	11,081	9,755	11,463	13,786
Agriculture, mining, and construction	1,858	2,135	2,344	2,552	2,165	2,540	2,922	2,257	2,712	3,200
Manufacturing	5,146	5,713	6,123	6,415	6,443	7,330	8,159	7,498	8,751	10,586
Energy-intensive	1,685	1,866	1,946	2,006	1,994	2,168	2,331	2,121	2,317	2,607
Non-energy-intensive	3,461	3,847	4,177	4,409	4,449	5,162	5,828	5,377	6,433	7,979
Total shipments	**31,402**	**34,878**	**36,935**	**38,566**	**39,720**	**44,838**	**49,433**	**44,532**	**52,277**	**60,396**
Population and employment (millions)										
Population, with armed forces overseas	317	333	334	335	354	359	363	371	380	390
Population, aged 16 and over	251	266	267	267	284	288	291	300	307	315
Population, aged 65 and over	45	56	56	56	73	73	73	80	80	81
Employment, nonfarm	136	146	149	152	153	159	166	160	169	176
Employment, manufacturing	11.9	11.3	11.8	12.2	9.7	10.7	11.4	8.4	9.7	10.7
Key labor indicators										
Labor force (millions)	155	165	166	166	171	174	177	179	185	190
Non-farm labor productivity (2009=1.00)	1.05	1.16	1.20	1.22	1.38	1.48	1.54	1.59	1.78	1.90
Unemployment rate (percent)	7.35	5.70	5.40	5.20	5.41	5.03	4.50	4.89	4.85	4.57
Key indicators for energy demand										
Real disposable personal income	11,651	13,944	14,411	14,900	17,469	18,487	19,806	21,555	22,957	24,875
Housing starts (millions)	0.99	1.21	1.69	2.28	1.05	1.66	2.44	0.96	1.62	2.55
Commercial floorspace (billion square feet)	82.8	88.6	89.0	89.5	96.8	98.4	100.1	106.0	109.1	112.4
Unit sales of light-duty vehicles (millions)	15.5	16.1	17.0	17.8	15.6	17.5	18.3	15.0	18.2	19.9

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2013: IHS Economics, Industry and Employment models, November 2014. **Projections:** U.S. Energy Information Administration, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

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Price case comparisons

Table C1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Production										
Crude oil and lease condensate	15.6	20.9	22.2	25.6	18.2	21.1	26.2	15.0	19.9	20.9
Natural gas plant liquids	3.6	5.3	5.5	5.8	5.4	5.7	6.3	5.0	5.5	6.2
Dry natural gas	25.1	28.3	29.6	30.9	31.0	33.9	39.1	32.8	36.4	42.2
Coal[1]	20.0	21.4	21.7	21.4	22.5	22.5	23.5	22.6	22.6	25.4
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.7	8.5	8.7	9.8
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[3]	4.2	4.4	4.4	4.5	4.6	4.6	4.8	4.7	5.0	5.7
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.0	4.1	4.6	6.4
Other[5]	1.3	0.9	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.0
Total	**82.7**	**95.6**	**98.7**	**103.8**	**97.4**	**103.7**	**116.5**	**96.5**	**106.6**	**120.5**
Imports										
Crude oil	17.0	14.7	13.6	14.6	17.0	15.7	15.3	19.2	18.2	21.0
Petroleum and other liquids[6]	4.3	5.4	4.6	3.8	5.6	4.4	4.2	5.3	4.1	4.0
Natural gas[7]	2.9	1.9	1.9	1.9	1.6	1.6	1.7	2.0	1.7	2.0
Other imports[8]	0.3	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.9
Total	**24.5**	**22.1**	**20.2**	**20.4**	**24.3**	**21.7**	**21.4**	**26.6**	**24.1**	**28.0**
Exports										
Petroleum and other liquids[9]	7.3	10.9	11.2	16.5	10.7	12.6	21.2	8.1	13.7	24.0
Natural gas[10]	1.6	3.1	4.5	4.5	4.0	6.4	10.2	5.0	7.4	11.2
Coal	2.9	2.5	2.5	2.4	3.3	3.3	3.0	3.7	3.5	3.3
Total	**11.7**	**16.5**	**18.1**	**23.4**	**18.0**	**22.4**	**34.4**	**16.8**	**24.6**	**38.5**
Discrepancy[11]	**-1.6**	**-0.1**	**-0.1**	**-0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Consumption										
Petroleum and other liquids[12]	35.9	37.8	37.1	35.8	37.8	36.5	33.7	38.6	36.2	32.9
Natural gas	26.9	26.8	26.8	28.0	28.4	28.8	30.2	29.6	30.5	31.8
Coal[13]	18.0	18.9	19.2	19.0	19.1	19.2	20.1	18.8	19.0	21.6
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.7	8.5	8.7	9.8
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[14]	2.9	3.0	3.0	3.1	3.1	3.2	3.4	3.3	3.5	4.0
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.0	4.1	4.6	6.4
Other[15]	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Total	**97.1**	**101.2**	**100.8**	**100.8**	**103.6**	**102.9**	**103.3**	**106.1**	**105.7**	**109.7**
Prices (2013 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	58	79	149	69	106	194	76	141	252
West Texas Intermediate	98	52	73	142	63	99	188	72	136	246
Natural gas at Henry Hub (dollars per million Btu)	3.73	4.30	4.88	4.61	5.49	5.69	7.89	7.15	7.85	10.63
Coal (dollars per ton) at the minemouth[16]	37.2	37.2	37.9	39.8	42.1	43.7	47.4	46.4	49.2	52.7
Coal (dollars per million Btu) at the minemouth[16]	1.84	1.85	1.88	1.98	2.11	2.18	2.35	2.31	2.44	2.62
Average end-use[17]	2.50	2.47	2.54	2.72	2.72	2.84	3.10	2.87	3.09	3.43
Average electricity (cents per kilowatthour)	10.1	10.4	10.5	10.5	11.0	11.1	11.8	11.5	11.8	12.9

Table C1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	65	90	167	91	142	263	120	229	416
West Texas Intermediate	98	58	83	159	83	133	255	115	220	407
Natural gas at Henry Hub (dollars per million Btu)	3.73	4.87	5.54	5.18	7.26	7.63	10.72	11.41	12.73	17.57
Coal (dollars per ton) at the minemouth[16]	37.2	42.1	43.0	44.8	55.7	58.6	64.4	74.0	79.8	87.1
Coal (dollars per million Btu)										
at the minemouth[16]	1.84	2.09	2.14	2.22	2.78	2.92	3.20	3.68	3.96	4.34
Average end-use[17]	2.50	2.79	2.88	3.06	3.60	3.81	4.22	4.58	5.00	5.67
Average electricity (cents per kilowatthour)	10.1	11.7	11.9	11.8	14.5	14.8	16.0	18.4	19.2	21.3

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2013 coal values: *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2013 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Energy consumption										
Residential										
Propane	0.43	0.33	0.32	0.31	0.29	0.28	0.26	0.26	0.25	0.23
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Distillate fuel oil	0.50	0.42	0.40	0.36	0.33	0.31	0.28	0.27	0.24	0.21
Petroleum and other liquids subtotal	0.93	0.76	0.73	0.68	0.63	0.59	0.54	0.53	0.49	0.45
Natural gas	5.05	4.65	4.63	4.64	4.53	4.52	4.43	4.35	4.31	4.20
Renewable energy[1]	0.58	0.37	0.41	0.53	0.32	0.38	0.48	0.28	0.35	0.45
Electricity	4.75	4.87	4.86	4.81	5.10	5.08	4.97	5.48	5.42	5.25
Delivered energy	**11.32**	**10.65**	**10.63**	**10.66**	**10.58**	**10.57**	**10.42**	**10.63**	**10.57**	**10.34**
Electricity related losses	9.79	9.75	9.75	9.58	9.94	9.91	9.74	10.38	10.33	10.30
Total	**21.10**	**20.40**	**20.38**	**20.25**	**20.52**	**20.48**	**20.16**	**21.01**	**20.91**	**20.64**
Commercial										
Propane	0.15	0.17	0.16	0.15	0.18	0.17	0.16	0.20	0.18	0.16
Motor gasoline[2]	0.05	0.05	0.05	0.04	0.06	0.05	0.05	0.06	0.06	0.05
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Distillate fuel oil	0.37	0.36	0.34	0.29	0.33	0.30	0.26	0.32	0.27	0.23
Residual fuel oil	0.03	0.08	0.07	0.05	0.08	0.07	0.05	0.09	0.06	0.05
Petroleum and other liquids subtotal	0.59	0.66	0.62	0.54	0.66	0.60	0.52	0.67	0.58	0.50
Natural gas	3.37	3.33	3.30	3.33	3.43	3.43	3.29	3.75	3.71	3.53
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.57	4.83	4.82	4.80	5.21	5.19	5.11	5.70	5.66	5.54
Delivered energy	**8.69**	**8.98**	**8.90**	**8.84**	**9.46**	**9.38**	**9.09**	**10.29**	**10.12**	**9.73**
Electricity related losses	9.42	9.66	9.68	9.57	10.14	10.13	10.01	10.80	10.80	10.87
Total	**18.10**	**18.64**	**18.58**	**18.41**	**19.60**	**19.52**	**19.10**	**21.09**	**20.92**	**20.60**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.51	3.24	3.20	3.28	3.79	3.72	3.72	3.78	3.67	3.76
Motor gasoline[2]	0.25	0.26	0.26	0.27	0.25	0.25	0.26	0.24	0.25	0.24
Distillate fuel oil	1.31	1.39	1.42	1.39	1.37	1.36	1.33	1.36	1.35	1.28
Residual fuel oil	0.06	0.13	0.10	0.09	0.17	0.13	0.11	0.18	0.13	0.12
Petrochemical feedstocks	0.74	0.97	0.95	0.98	1.15	1.14	1.13	1.19	1.20	1.16
Other petroleum[6]	3.52	3.73	3.67	3.95	3.88	3.83	3.96	4.03	3.99	4.06
Petroleum and other liquids subtotal	8.40	9.72	9.61	9.96	10.61	10.44	10.52	10.79	10.59	10.62
Natural gas	7.62	8.20	8.33	8.50	8.56	8.65	8.82	8.50	8.90	9.29
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.96
Lease and plant fuel[7]	1.52	1.67	1.87	1.98	1.75	2.10	2.94	1.80	2.29	3.31
Natural gas subtotal	9.14	9.87	10.20	10.48	10.30	10.75	11.92	10.30	11.19	13.55
Metallurgical coal	0.62	0.58	0.61	0.65	0.55	0.56	0.61	0.48	0.51	0.58
Other industrial coal	0.88	0.92	0.93	0.97	0.94	0.96	1.04	0.95	0.99	1.13
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.68	0.00	0.00	1.97
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.05
Coal subtotal	1.48	1.50	1.54	1.63	1.46	1.48	2.29	1.38	1.44	3.63
Biofuels heat and coproducts	0.72	0.82	0.80	0.80	0.81	0.80	0.81	0.80	0.86	0.98
Renewable energy[8]	1.48	1.55	1.53	1.59	1.61	1.59	1.61	1.61	1.63	1.81
Electricity	3.26	3.75	3.74	3.98	4.02	4.04	4.21	4.00	4.12	4.35
Delivered energy	**24.48**	**27.21**	**27.42**	**28.43**	**28.81**	**29.10**	**31.36**	**28.86**	**29.82**	**34.95**
Electricity related losses	6.72	7.51	7.51	7.93	7.83	7.88	8.25	7.58	7.85	8.54
Total	**31.20**	**34.72**	**34.93**	**36.36**	**36.64**	**36.98**	**39.61**	**36.44**	**37.68**	**43.48**

Table C2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Transportation										
Propane	0.05	0.04	0.04	0.06	0.05	0.05	0.07	0.05	0.07	0.09
Motor gasoline[2]	15.94	15.94	15.35	13.98	14.31	13.30	11.44	14.18	12.55	10.54
of which: E85[9]	0.02	0.02	0.03	0.19	0.14	0.20	0.52	0.16	0.28	0.76
Jet fuel[10]	2.80	3.02	3.01	2.97	3.42	3.40	3.37	3.65	3.64	3.61
Distillate fuel oil[11]	6.50	7.27	7.35	7.26	7.84	7.76	6.88	8.44	7.97	6.68
Residual fuel oil	0.57	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36
Other petroleum[12]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Petroleum and other liquids subtotal	26.00	26.78	26.27	24.79	26.13	25.03	22.28	26.84	24.76	21.46
Pipeline fuel natural gas	0.88	0.83	0.85	0.89	0.90	0.94	1.04	0.91	0.96	1.07
Compressed / liquefied natural gas	0.05	0.06	0.07	0.39	0.06	0.17	1.31	0.06	0.71	2.47
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.08
Delivered energy	**26.96**	**27.70**	**27.22**	**26.10**	**27.13**	**26.18**	**24.68**	**27.87**	**26.49**	**25.08**
Electricity related losses	0.05	0.06	0.06	0.07	0.08	0.08	0.10	0.10	0.12	0.16
Total	**27.01**	**27.76**	**27.29**	**26.17**	**27.21**	**26.27**	**24.78**	**27.98**	**26.61**	**25.24**
Unspecified sector[13]	**-0.27**	**-0.33**	**-0.34**	**-0.35**	**-0.37**	**-0.37**	**-0.31**	**-0.41**	**-0.38**	**-0.29**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	3.14	3.78	3.73	3.79	4.31	4.23	4.21	4.29	4.17	4.25
Motor gasoline[2]	16.36	16.38	15.79	14.41	14.74	13.72	11.84	14.60	12.96	10.91
of which: E85[9]	0.02	0.02	0.03	0.19	0.14	0.20	0.52	0.16	0.28	0.76
Jet fuel[10]	2.97	3.20	3.20	3.15	3.62	3.61	3.57	3.88	3.86	3.83
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.10	8.80	8.86	8.66	9.18	9.05	8.14	9.63	9.13	7.81
Residual fuel oil	0.65	0.57	0.53	0.50	0.61	0.56	0.52	0.63	0.56	0.53
Petrochemical feedstocks	0.74	0.97	0.95	0.98	1.15	1.14	1.13	1.19	1.20	1.16
Other petroleum[14]	3.67	3.89	3.82	4.11	4.04	3.98	4.12	4.19	4.15	4.22
Petroleum and other liquids subtotal	35.65	37.59	36.89	35.61	37.66	36.30	33.54	38.43	36.03	32.73
Natural gas	16.10	16.24	16.32	16.86	16.57	16.76	17.84	16.67	17.64	19.48
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.96
Lease and plant fuel[7]	1.52	1.67	1.87	1.98	1.75	2.10	2.94	1.80	2.29	3.31
Pipeline natural gas	0.88	0.83	0.85	0.89	0.90	0.94	1.04	0.91	0.96	1.07
Natural gas subtotal	18.50	18.73	19.05	19.73	19.21	19.80	21.99	19.37	20.88	24.81
Metallurgical coal	0.62	0.58	0.61	0.65	0.55	0.56	0.61	0.48	0.51	0.58
Other coal	0.92	0.97	0.98	1.02	0.99	1.00	1.09	1.00	1.04	1.18
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.68	0.00	0.00	1.97
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.05
Coal subtotal	1.52	1.55	1.59	1.67	1.51	1.53	2.34	1.42	1.49	3.68
Biofuels heat and coproducts	0.72	0.82	0.80	0.80	0.81	0.80	0.81	0.80	0.86	0.98
Renewable energy[15]	2.18	2.04	2.06	2.23	2.05	2.09	2.22	2.01	2.10	2.38
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.60	13.48	13.45	13.63	14.37	14.35	14.34	15.23	15.25	15.21
Delivered energy	**71.17**	**74.22**	**73.84**	**73.68**	**75.61**	**74.87**	**75.24**	**77.25**	**76.62**	**79.80**
Electricity related losses	25.97	26.98	27.00	27.15	27.99	28.01	28.09	28.86	29.10	29.87
Total	**97.14**	**101.20**	**100.84**	**100.84**	**103.60**	**102.87**	**103.34**	**106.11**	**105.73**	**109.67**
Electric power[16]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Residual fuel oil	0.21	0.08	0.08	0.09	0.09	0.09	0.09	0.11	0.09	0.09
Petroleum and other liquids subtotal	0.26	0.17	0.17	0.17	0.18	0.17	0.17	0.19	0.18	0.18
Natural gas	8.36	8.07	7.80	8.28	9.21	9.03	8.25	10.19	9.61	7.02
Steam coal	16.49	17.37	17.59	17.33	17.58	17.63	17.77	17.41	17.52	17.88
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.67	8.52	8.73	9.78
Renewable energy[18]	4.78	6.08	6.13	6.24	6.59	6.72	7.22	7.46	7.99	9.85
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.10	0.10	0.12	0.11	0.11	0.15
Total	**38.57**	**40.46**	**40.45**	**40.78**	**42.36**	**42.35**	**42.43**	**44.09**	**44.36**	**45.08**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Total energy consumption										
Liquefied petroleum gases and other[5]	3.14	3.78	3.73	3.79	4.31	4.23	4.21	4.29	4.17	4.25
Motor gasoline[2]	16.36	16.38	15.79	14.41	14.74	13.72	11.84	14.60	12.96	10.91
of which: E85[9]	0.02	0.02	0.03	0.19	0.14	0.20	0.52	0.16	0.28	0.76
Jet fuel[10]	2.97	3.20	3.20	3.15	3.62	3.61	3.57	3.88	3.86	3.83
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.15	8.88	8.95	8.75	9.27	9.13	8.23	9.71	9.21	7.90
Residual fuel oil	0.87	0.65	0.61	0.59	0.70	0.64	0.61	0.74	0.65	0.62
Petrochemical feedstocks	0.74	0.97	0.95	0.98	1.15	1.14	1.13	1.19	1.20	1.16
Other petroleum[14]	3.67	3.89	3.82	4.11	4.04	3.98	4.12	4.19	4.15	4.22
Petroleum and other liquids subtotal	35.91	37.77	37.06	35.79	37.84	36.47	33.72	38.61	36.21	32.91
Natural gas	24.46	24.31	24.12	25.14	25.78	25.79	26.09	26.86	27.25	26.50
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.96
Lease and plant fuel[7]	1.52	1.67	1.87	1.98	1.75	2.10	2.94	1.80	2.29	3.31
Pipeline natural gas	0.88	0.83	0.85	0.89	0.90	0.94	1.04	0.91	0.96	1.07
Natural gas subtotal	26.86	26.81	26.85	28.02	28.43	28.83	30.24	29.56	30.50	31.83
Metallurgical coal	0.62	0.58	0.61	0.65	0.55	0.56	0.61	0.48	0.51	0.58
Other coal	17.41	18.34	18.57	18.35	18.57	18.63	18.86	18.40	18.56	19.06
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.68	0.00	0.00	1.97
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.05
Coal subtotal	18.01	18.92	19.18	19.00	19.09	19.16	20.11	18.83	19.01	21.56
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.67	8.52	8.73	9.78
Biofuels heat and coproducts	0.72	0.82	0.80	0.80	0.81	0.80	0.81	0.80	0.86	0.98
Renewable energy[19]	6.96	8.12	8.19	8.47	8.64	8.81	9.44	9.46	10.09	12.23
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.10	0.10	0.12	0.11	0.11	0.15
Total	**97.14**	**101.20**	**100.84**	**100.84**	**103.60**	**102.87**	**103.34**	**106.11**	**105.73**	**109.67**
Energy use and related statistics										
Delivered energy use	71.17	74.22	73.84	73.68	75.61	74.87	75.24	77.25	76.62	79.80
Total energy use	97.14	101.20	100.84	100.84	103.60	102.87	103.34	106.11	105.73	109.67
Ethanol consumed in motor gasoline and E85	1.12	1.16	1.12	1.13	1.11	1.12	1.17	1.12	1.27	1.28
Population (millions)	317	334	334	334	359	359	359	380	380	380
Gross domestic product (billion 2009 dollars)	15,710	18,742	18,801	18,798	23,963	23,894	23,844	29,885	29,898	29,760
Carbon dioxide emissions (million metric tons)	5,405	5,523	5,499	5,441	5,585	5,514	5,461	5,671	5,549	5,584

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE-EIA-0035(2014/11) (Washington, DC, November 2014). 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C3. Energy prices by sector and source
(2013 dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil Price	Reference	High oil price
Residential										
Propane	23.3	21.2	23.0	26.6	22.2	24.4	28.6	23.0	26.6	30.8
Distillate fuel oil	27.2	17.5	21.5	34.6	19.5	26.3	43.3	20.5	32.9	53.7
Natural gas	10.0	11.1	11.6	11.3	12.8	12.8	14.7	14.8	15.5	17.9
Electricity	35.6	37.3	37.8	38.3	39.6	40.0	42.7	41.3	42.4	46.3
Commercial										
Propane	20.0	17.2	19.4	23.9	18.4	21.1	26.6	19.4	23.9	29.5
Distillate fuel oil	26.7	16.9	21.0	34.1	19.0	25.8	42.9	19.9	32.5	53.3
Residual fuel oil	22.1	11.0	14.2	24.4	12.6	18.1	31.7	13.5	24.3	42.7
Natural gas	8.1	9.1	9.6	9.3	10.4	10.4	12.2	12.0	12.6	15.0
Electricity	29.7	30.8	31.1	31.3	32.3	32.6	34.9	33.6	34.5	37.8
Industrial[1]										
Propane	20.3	17.3	19.6	24.5	18.6	21.5	27.3	19.7	24.5	30.5
Distillate fuel oil	27.3	17.1	21.2	34.3	19.3	26.1	43.2	20.2	32.7	53.6
Residual fuel oil	20.0	10.2	13.3	23.5	11.8	17.2	30.7	12.7	23.5	41.7
Natural gas[2]	4.6	5.6	6.2	5.8	6.8	6.8	8.7	8.2	8.8	11.0
Metallurgical coal	5.5	5.8	5.8	6.0	6.6	6.7	6.9	7.0	7.2	7.5
Other industrial coal	3.2	3.3	3.3	3.5	3.5	3.6	3.9	3.7	3.9	4.3
Coal to liquids	- -	- -	- -	- -	- -	- -	2.6	- -	- -	3.1
Electricity	20.2	20.9	21.3	21.3	22.4	22.6	24.5	24.0	24.7	27.3
Transportation										
Propane	24.6	22.2	24.0	27.6	23.2	25.5	29.6	24.1	27.6	31.8
E85[3]	33.1	28.4	30.4	36.6	25.6	31.2	39.3	28.2	35.4	47.5
Motor gasoline[4]	29.3	19.2	22.5	34.4	20.2	26.4	41.7	21.4	32.3	52.5
Jet fuel[5]	21.8	12.1	16.1	28.9	14.4	21.3	38.2	15.6	28.3	48.8
Diesel fuel (distillate fuel oil)[6]	28.2	19.1	23.1	36.3	21.3	28.0	45.0	22.1	34.7	55.6
Residual fuel oil	19.3	8.7	11.7	21.0	10.5	15.4	27.6	11.3	20.3	35.4
Natural gas[7]	17.6	17.8	17.8	18.8	18.6	15.7	20.9	19.7	19.6	22.9
Electricity	28.5	29.8	30.2	30.2	32.5	32.9	35.9	34.8	36.0	40.3
Electric power[8]										
Distillate fuel oil	24.0	14.7	18.8	31.8	16.7	23.6	40.6	17.7	30.2	51.0
Residual fuel oil	18.9	8.3	11.5	21.7	9.7	15.4	28.9	10.4	21.6	40.0
Natural gas	4.4	4.9	5.4	5.1	6.2	6.2	7.9	7.8	8.3	10.1
Steam coal	2.3	2.3	2.4	2.6	2.6	2.7	3.0	2.7	2.9	3.3
Average price to all users[9]										
Propane	21.9	19.0	21.1	25.3	19.8	22.6	27.7	20.8	25.2	30.5
E85[3]	33.1	28.4	30.4	36.6	25.6	31.2	39.3	28.2	35.4	47.5
Motor gasoline[4]	29.0	19.2	22.5	34.4	20.2	26.4	41.7	21.4	32.3	52.5
Jet fuel[5]	21.8	12.1	16.1	28.9	14.4	21.3	38.2	15.6	28.3	48.8
Distillate fuel oil	27.9	18.6	22.6	35.8	20.8	27.6	44.6	21.7	34.2	55.1
Residual fuel oil	19.4	9.3	12.2	21.8	10.9	16.0	28.7	11.8	21.5	37.8
Natural gas	6.1	6.9	7.5	7.3	8.1	8.2	10.5	9.7	10.5	13.4
Metallurgical coal	5.5	5.8	5.8	6.0	6.6	6.7	6.9	7.0	7.2	7.5
Other coal	2.4	2.4	2.4	2.6	2.6	2.7	3.0	2.8	3.0	3.4
Coal to liquids	- -	- -	- -	- -	- -	- -	2.6	- -	- -	3.1
Electricity	29.5	30.4	30.8	30.8	32.1	32.4	34.5	33.8	34.7	37.7
Non-renewable energy expenditures by sector (billion 2013 dollars)										
Residential	243	248	254	258	273	276	297	302	311	336
Commercial	177	190	194	198	216	219	238	249	259	284
Industrial[1]	224	236	264	334	285	323	439	312	389	547
Transportation	719	481	565	831	503	638	926	544	791	1,128
Total non-renewable expenditures	1,364	1,155	1,276	1,621	1,276	1,456	1,900	1,408	1,751	2,295
Transportation renewable expenditures	1	1	1	7	4	6	20	4	10	36
Total expenditures	**1,364**	**1,155**	**1,277**	**1,628**	**1,280**	**1,462**	**1,920**	**1,412**	**1,761**	**2,331**

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Propane	23.3	24.0	26.1	29.9	29.3	32.8	38.9	36.7	43.1	50.9
Distillate fuel oil	27.2	19.8	24.4	38.8	25.8	35.3	58.8	32.7	53.3	88.7
Natural gas	10.0	12.5	13.2	12.7	16.9	17.1	20.0	23.6	25.1	29.6
Electricity	35.6	42.2	42.9	43.1	52.4	53.6	58.0	65.9	68.8	76.4
Commercial										
Propane	20.0	19.5	22.0	26.9	24.3	28.3	36.1	31.0	38.8	48.8
Distillate fuel oil	26.7	19.1	23.8	38.3	25.1	34.6	58.2	31.8	52.6	88.1
Residual fuel oil	22.1	12.4	16.1	27.5	16.7	24.3	43.0	21.5	39.4	70.6
Natural gas	8.1	10.3	10.8	10.4	13.8	13.9	16.6	19.1	20.5	24.7
Electricity	29.7	34.8	35.3	35.1	42.8	43.7	47.4	53.6	56.0	62.4
Industrial[1]										
Propane	20.3	19.6	22.3	27.5	24.5	28.8	37.1	31.4	39.7	50.4
Distillate fuel oil	27.3	19.4	24.1	38.6	25.5	35.0	58.6	32.2	53.0	88.6
Residual fuel oil	20.0	11.5	15.1	26.4	15.6	23.1	41.6	20.2	38.0	68.9
Natural gas[2]	4.6	6.4	7.0	6.5	9.0	9.1	11.8	13.2	14.2	18.2
Metallurgical coal	5.5	6.5	6.6	6.7	8.7	8.9	9.3	11.2	11.6	12.4
Other industrial coal	3.2	3.7	3.8	3.9	4.6	4.8	5.2	5.9	6.3	7.1
Coal to liquids	- -	- -	- -	- -	- -	- -	3.5	- -	- -	5.1
Electricity	20.2	23.6	24.2	24.0	29.6	30.3	33.2	38.2	40.0	45.1
Transportation										
Propane	24.6	25.1	27.2	31.1	30.6	34.1	40.3	38.4	44.8	52.6
E85[3]	33.1	32.1	34.4	41.1	33.9	41.9	53.3	44.9	57.4	78.5
Motor gasoline[4]	29.3	21.7	25.5	38.6	26.7	35.3	56.6	34.1	52.4	86.8
Jet fuel[5]	21.8	13.7	18.3	32.5	19.0	28.6	51.9	24.9	45.8	80.6
Diesel fuel (distillate fuel oil)[6]	28.2	21.6	26.2	40.7	28.1	37.6	61.2	35.3	56.2	91.8
Residual fuel oil	19.3	9.9	13.2	23.6	13.8	20.6	37.5	18.0	32.9	58.4
Natural gas[7]	17.6	20.2	20.2	21.2	24.6	21.0	28.5	31.4	31.8	37.8
Electricity	28.5	33.8	34.3	34.0	43.0	44.1	48.7	55.6	58.4	66.6
Electric power[8]										
Distillate fuel oil	24.0	16.7	21.3	35.8	22.1	31.7	55.2	28.3	49.0	84.3
Residual fuel oil	18.9	9.4	13.0	24.3	12.8	20.6	39.3	16.5	35.0	66.0
Natural gas	4.4	5.6	6.1	5.8	8.2	8.3	10.7	12.4	13.4	16.7
Steam coal	2.3	2.6	2.7	2.9	3.4	3.6	4.0	4.3	4.7	5.5

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections 2020 Low oil price	2020 Reference	2020 High oil price	2030 Low oil price	2030 Reference	2030 High oil price	2040 Low oil price	2040 Reference	2040 High oil price
Average price to all users[9]										
Propane	21.9	21.5	23.9	28.5	26.2	30.3	37.7	33.1	40.9	50.4
E85[3]	33.1	32.1	34.4	41.1	33.9	41.9	53.3	44.9	57.4	78.5
Motor gasoline[4]	29.0	21.7	25.5	38.6	26.7	35.3	56.6	34.1	52.4	86.8
Jet fuel[5]	21.8	13.7	18.3	32.5	19.0	28.6	51.9	24.9	45.8	80.6
Distillate fuel oil	27.9	21.0	25.7	40.2	27.5	36.9	60.6	34.6	55.5	91.0
Residual fuel oil	19.4	10.5	13.8	24.5	14.5	21.5	39.0	18.8	34.8	62.5
Natural gas	6.1	7.8	8.5	8.2	10.7	11.0	14.3	15.4	17.0	22.2
Metallurgical coal	5.5	6.5	6.6	6.7	8.7	8.9	9.3	11.2	11.6	12.4
Other coal	2.4	2.7	2.8	2.9	3.4	3.7	4.1	4.4	4.8	5.6
Coal to liquids	- -	- -	- -	- -	- -	- -	3.5	- -	- -	5.1
Electricity	29.5	34.4	34.9	34.7	42.5	43.4	46.9	54.0	56.2	62.3
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	243	280	288	290	361	370	403	482	504	556
Commercial	177	215	220	222	286	294	323	398	420	470
Industrial[1]	224	267	299	376	376	433	597	498	631	903
Transportation	719	544	641	934	664	855	1,258	868	1,283	1,864
Total non-renewable expenditures	1,364	1,307	1,448	1,822	1,687	1,952	2,581	2,246	2,839	3,793
Transportation renewable expenditures	1	1	1	8	5	8	28	7	16	60
Total expenditures	**1,364**	**1,308**	**1,449**	**1,830**	**1,692**	**1,960**	**2,609**	**2,253**	**2,855**	**3,852**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 transportation sector natural gas delivered prices are model results. 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C4. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil										
Domestic crude production[1]	7.44	9.96	10.60	12.29	8.69	10.04	12.48	7.09	9.43	9.93
Alaska	0.52	0.42	0.42	0.42	0.00	0.24	0.57	0.00	0.34	0.45
Lower 48 states	6.92	9.55	10.18	11.87	8.69	9.80	11.92	7.09	9.09	9.48
Net imports	7.60	6.02	5.51	5.94	7.07	6.44	6.24	8.05	7.58	8.86
Gross imports	7.73	6.65	6.14	6.57	7.70	7.07	6.87	8.68	8.21	9.49
Exports	0.13	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Other crude supply[2]	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**15.30**	**15.99**	**16.11**	**18.23**	**15.76**	**16.48**	**18.72**	**15.14**	**17.01**	**18.78**
Net product imports	-1.37	-2.19	-2.80	-5.97	-1.88	-3.56	-8.06	-0.71	-4.26	-9.49
Gross refined product imports[3]	0.82	1.45	1.21	0.88	1.72	1.31	1.27	1.65	1.26	1.31
Unfinished oil imports	0.66	0.68	0.60	0.49	0.66	0.52	0.39	0.62	0.45	0.31
Blending component imports	0.60	0.72	0.59	0.51	0.62	0.49	0.50	0.53	0.40	0.44
Exports	3.43	5.04	5.20	7.86	4.88	5.89	10.23	3.51	6.36	11.54
Refinery processing gain[4]	1.09	0.96	0.98	1.07	0.94	0.97	0.99	1.00	0.98	1.01
Product stock withdrawal	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas plant liquids	2.61	3.92	4.04	4.29	3.99	4.19	4.65	3.71	4.07	4.55
Supply from renewable sources	0.93	1.03	1.01	1.02	1.00	1.01	1.05	1.00	1.12	1.25
Ethanol	0.83	0.87	0.84	0.85	0.83	0.84	0.88	0.83	0.95	0.96
Domestic production	0.85	0.88	0.86	0.86	0.87	0.86	0.87	0.86	0.93	0.90
Net imports	-0.02	-0.02	-0.02	-0.01	-0.04	-0.02	0.01	-0.02	0.02	0.06
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.10	0.13	0.14	0.14	0.01	0.11	0.14	0.01	0.11	0.15
Domestic production	0.09	0.13	0.13	0.13	0.00	0.10	0.13	0.00	0.10	0.14
Net imports	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other biomass-derived liquids[5]	0.00	0.03	0.03	0.03	0.15	0.06	0.03	0.15	0.06	0.15
Domestic production	0.00	0.03	0.03	0.03	0.15	0.06	0.03	0.15	0.06	0.15
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.49
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.71
Other[6]	0.21	0.27	0.28	0.30	0.29	0.30	0.32	0.29	0.32	0.35
Total primary supply[7]	**18.87**	**19.98**	**19.62**	**18.94**	**20.10**	**19.38**	**18.00**	**20.43**	**19.24**	**17.66**
Product supplied										
by fuel										
Liquefied petroleum gases and other[8]	2.50	2.94	2.91	2.96	3.34	3.30	3.31	3.31	3.25	3.34
Motor gasoline[9]	8.85	8.80	8.49	7.77	7.94	7.41	6.44	7.86	7.05	6.02
of which: E85[10]	0.01	0.01	0.02	0.13	0.09	0.13	0.36	0.11	0.19	0.52
Jet fuel[11]	1.43	1.55	1.55	1.53	1.76	1.75	1.73	1.88	1.87	1.86
Distillate fuel oil[12]	3.83	4.22	4.26	4.16	4.41	4.34	3.91	4.62	4.38	3.77
of which: Diesel	3.56	3.90	3.94	3.88	4.13	4.09	3.68	4.38	4.17	3.57
Residual fuel oil	0.32	0.28	0.27	0.26	0.31	0.28	0.27	0.32	0.28	0.27
Other[13]	2.04	2.20	2.18	2.30	2.36	2.33	2.39	2.45	2.43	2.45
by sector										
Residential and commercial	0.86	0.79	0.76	0.69	0.72	0.67	0.60	0.68	0.61	0.54
Industrial[14]	4.69	5.54	5.50	5.66	6.12	6.04	6.09	6.17	6.09	6.16
Transportation	13.36	13.74	13.46	12.70	13.35	12.79	11.42	13.69	12.66	11.04
Electric power[15]	0.12	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Unspecified sector[16]	-0.12	-0.15	-0.15	-0.16	-0.17	-0.17	-0.14	-0.18	-0.17	-0.13
Total product supplied	**18.96**	**20.00**	**19.65**	**18.97**	**20.10**	**19.41**	**18.04**	**20.44**	**19.27**	**17.70**
Discrepancy[17]	-0.10	-0.02	-0.03	-0.03	0.00	-0.03	-0.04	-0.01	-0.03	-0.04

Table C4. Petroleum and other liquids supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Domestic refinery distillation capacity[18]	17.8	18.8	18.8	19.0	18.8	18.8	19.3	18.8	18.8	19.3
Capacity utilization rate (percent)[19]	88.3	87.4	87.8	97.6	86.1	89.4	98.6	82.7	92.0	98.6
Net import share of product supplied (percent)	33.0	19.1	13.7	-0.2	25.7	14.8	-10.0	35.9	17.4	-3.2
Net expenditures for imported crude oil and petroleum products (billion 2013 dollars)	308	130	167	345	180	259	468	225	405	836

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). Other 2013 data: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C5. Petroleum and other liquids prices
(2013 dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2013 dollars per barrel)										
Brent spot	109	58	79	149	69	106	194	76	141	252
West Texas Intermediate spot	98	52	73	142	63	99	188	72	136	246
Average imported refiners acquisition cost[1]	98	50	71	139	61	96	181	68	131	237
Brent / West Texas Intermediate spread	10.7	6.1	6.2	6.8	5.9	6.2	6.3	3.4	5.6	5.7
Delivered sector product prices										
Residential										
Propane	2.13	1.93	2.10	2.43	2.02	2.23	2.61	2.10	2.43	2.81
Distillate fuel oil	3.78	2.42	2.99	4.79	2.71	3.65	6.00	2.84	4.56	7.44
Commercial										
Distillate fuel oil	3.68	2.33	2.89	4.70	2.62	3.56	5.91	2.75	4.47	7.35
Residual fuel oil	3.31	1.64	2.12	3.66	1.89	2.71	4.74	2.02	3.64	6.40
Residual fuel oil (2013 dollars per barrel)	139	69	89	154	79	114	199	85	153	269
Industrial[2]										
Propane	1.85	1.58	1.79	2.24	1.70	1.96	2.49	1.80	2.24	2.78
Distillate fuel oil	3.75	2.35	2.91	4.71	2.65	3.58	5.92	2.77	4.49	7.36
Residual fuel oil	3.00	1.52	2.00	3.52	1.76	2.58	4.59	1.89	3.51	6.24
Residual fuel oil (2013 dollars per barrel)	126	64	84	148	74	108	193	80	147	262
Transportation										
Propane	2.24	2.03	2.19	2.52	2.12	2.32	2.71	2.20	2.52	2.91
E85[3]	3.14	2.71	2.90	3.49	2.44	2.98	3.75	2.69	3.38	4.53
Ethanol wholesale price	2.37	2.49	2.49	2.63	2.22	2.35	2.67	2.30	2.64	3.26
Motor gasoline[4]	3.55	2.33	2.74	4.17	2.45	3.20	5.05	2.60	3.90	6.33
Jet fuel[5]	2.94	1.63	2.17	3.90	1.95	2.88	5.16	2.11	3.81	6.58
Diesel fuel (distillate fuel oil)[6]	3.86	2.61	3.17	4.97	2.91	3.84	6.17	3.03	4.75	7.61
Residual fuel oil	2.89	1.31	1.74	3.14	1.57	2.30	4.13	1.69	3.03	5.29
Residual fuel oil (2013 dollars per barrel)	122	55	73	132	66	97	174	71	127	222
Electric power[7]										
Distillate fuel oil	3.33	2.04	2.60	4.42	2.32	3.28	5.63	2.46	4.19	7.07
Residual fuel oil	2.83	1.24	1.71	3.24	1.45	2.30	4.33	1.55	3.23	5.98
Residual fuel oil (2013 dollars per barrel)	119	52	72	136	61	97	182	65	136	251
Average prices, all sectors[8]										
Propane	2.00	1.73	1.93	2.31	1.81	2.06	2.53	1.90	2.30	2.79
Motor gasoline[4]	3.53	2.33	2.74	4.17	2.45	3.20	5.05	2.60	3.90	6.33
Jet fuel[5]	2.94	1.63	2.17	3.90	1.95	2.88	5.16	2.11	3.81	6.58
Distillate fuel oil	3.83	2.55	3.11	4.91	2.85	3.78	6.12	2.97	4.69	7.55
Residual fuel oil	2.90	1.38	1.83	3.26	1.64	2.40	4.30	1.76	3.22	5.66
Residual fuel oil (2013 dollars per barrel)	121.71	58.16	76.70	137.11	68.77	100.80	180.46	73.94	135.10	237.79
Average	**3.16**	**2.04**	**2.46**	**3.84**	**2.18**	**2.89**	**4.66**	**2.32**	**3.62**	**5.81**

Table C5. Petroleum and other liquids prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (nominal dollars per barrel)										
Brent spot	109	65	90	167	91	142	263	120	229	416
West Texas Intermediate spot	98	58	83	159	83	133	255	115	220	407
Average imported refiners acquisition cost[1]	98	57	80	156	81	129	246	108	212	391
Delivered sector product prices										
Residential										
Propane	2.13	2.19	2.38	2.73	2.67	2.99	3.55	3.36	3.94	4.65
Distillate fuel oil	3.78	2.74	3.39	5.39	3.58	4.90	8.16	4.54	7.40	12.30
Commercial										
Distillate fuel oil	3.68	2.64	3.28	5.28	3.46	4.78	8.03	4.38	7.25	12.14
Residual fuel oil	3.31	1.86	2.41	4.11	2.50	3.63	6.44	3.22	5.90	10.57
Industrial[2]										
Propane	1.85	1.79	2.04	2.51	2.24	2.63	3.39	2.87	3.62	4.60
Distillate fuel oil	3.75	2.66	3.30	5.30	3.50	4.80	8.05	4.42	7.28	12.16
Residual fuel oil	3.00	1.72	2.26	3.95	2.33	3.46	6.23	3.02	5.69	10.31
Transportation										
Propane	2.24	2.30	2.49	2.84	2.80	3.12	3.68	3.50	4.09	4.80
E85[3]	3.14	3.06	3.29	3.92	3.23	3.99	5.09	4.28	5.48	7.49
Ethanol wholesale price	2.37	2.82	2.83	2.96	2.94	3.15	3.62	3.68	4.27	5.39
Motor gasoline[4]	3.55	2.64	3.10	4.69	3.24	4.29	6.86	4.15	6.32	10.46
Jet fuel[5]	2.94	1.85	2.47	4.38	2.57	3.86	7.01	3.36	6.18	10.88
Diesel fuel (distillate fuel oil)[6]	3.86	2.96	3.60	5.58	3.85	5.15	8.39	4.83	7.70	12.58
Residual fuel oil	2.89	1.48	1.98	3.53	2.07	3.08	5.61	2.70	4.92	8.75
Electric power[7]										
Distillate fuel oil	3.33	2.31	2.95	4.96	3.07	4.39	7.65	3.93	6.79	11.69
Residual fuel oil	2.83	1.40	1.94	3.64	1.92	3.09	5.88	2.48	5.24	9.88
Average prices, all sectors[8]										
Propane	2.00	1.96	2.19	2.60	2.40	2.77	3.44	3.02	3.73	4.61
Motor gasoline[4]	3.53	2.64	3.10	4.69	3.24	4.29	6.86	4.14	6.32	10.46
Jet fuel[5]	2.94	1.85	2.47	4.38	2.57	3.86	7.01	3.36	6.18	10.88
Distillate fuel oil	3.83	2.88	3.52	5.51	3.77	5.07	8.31	4.74	7.61	12.48
Residual fuel oil (nominal dollars per barrel)	122	66	87	154	91	135	245	118	219	393
Average	**3.16**	**2.30**	**2.79**	**4.32**	**2.88**	**3.88**	**6.33**	**3.70**	**5.86**	**9.61**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2013 average imported crude oil price: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2013 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2013 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C6. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil spot prices										
(2013 dollars per barrel)										
Brent	109	58	79	149	69	106	194	76	141	252
West Texas Intermediate	98	52	73	142	63	99	188	72	136	246
(nominal dollars per barrel)										
Brent	109	65	90	167	91	142	263	120	229	416
West Texas Intermediate	98	58	83	159	83	133	255	115	220	407
Petroleum and other liquids consumption[1]										
OECD										
United States (50 states)	18.96	20.00	19.65	18.97	20.10	19.41	18.04	20.44	19.27	17.70
United States territories	0.30	0.32	0.31	0.30	0.35	0.34	0.33	0.40	0.38	0.38
Canada	2.29	2.40	2.31	2.20	2.45	2.21	2.06	2.61	2.14	1.94
Mexico and Chile	2.46	2.79	2.71	2.63	2.95	2.80	2.78	3.19	2.92	2.88
OECD Europe[2]	13.96	14.75	14.20	13.74	15.30	14.09	13.70	16.03	14.12	13.54
Japan	4.56	4.47	4.27	4.05	4.36	4.03	3.79	4.05	3.65	3.31
South Korea	2.43	2.71	2.58	2.42	2.80	2.53	2.36	2.81	2.40	2.24
Australia and New Zealand	1.16	1.19	1.16	1.13	1.17	1.11	1.09	1.26	1.15	1.11
Total OECD consumption	**46.14**	**48.62**	**47.20**	**45.43**	**49.49**	**46.52**	**44.16**	**50.79**	**46.04**	**43.10**
Non-OECD										
Russia	3.30	3.32	3.31	3.19	3.32	3.23	3.01	3.22	3.01	2.67
Other Europe and Eurasia[3]	2.06	2.22	2.22	2.20	2.45	2.39	2.33	2.78	2.59	2.48
China	10.67	13.05	13.13	13.04	15.95	17.03	18.31	17.38	20.19	24.04
India	3.70	4.32	4.30	4.14	5.39	5.52	5.37	6.14	6.79	6.91
Other Asia[4]	7.37	9.14	9.08	8.83	12.37	12.35	12.26	16.24	16.49	16.84
Middle East	7.61	8.49	8.40	8.42	10.20	9.56	10.22	12.50	11.13	12.72
Africa	3.42	3.99	3.93	3.82	4.93	4.78	4.75	6.41	6.18	6.28
Brazil	3.11	3.44	3.33	3.15	3.93	3.74	3.62	4.80	4.50	4.50
Other Central and South America	3.38	3.56	3.49	3.38	3.86	3.72	3.64	4.39	4.15	4.11
Total non-OECD consumption	**44.60**	**51.54**	**51.20**	**50.17**	**62.41**	**62.31**	**63.50**	**73.87**	**75.01**	**80.54**
Total consumption	**90.7**	**100.2**	**98.4**	**95.6**	**111.9**	**108.8**	**107.7**	**124.7**	**121.0**	**123.6**
Petroleum and other liquids production										
OPEC[5]										
Middle East	26.32	27.65	24.56	19.33	35.80	29.34	21.86	45.31	36.14	29.01
North Africa	2.90	3.74	3.51	3.22	4.31	3.67	3.42	4.90	4.06	3.67
West Africa	4.26	5.51	5.00	4.43	6.85	5.24	4.81	7.50	5.43	5.01
South America	3.01	3.64	3.10	2.85	4.58	3.27	2.93	5.59	3.79	3.18
Total OPEC production	**36.49**	**40.54**	**36.16**	**29.83**	**51.54**	**41.53**	**33.01**	**63.30**	**49.42**	**40.87**
Non-OPEC										
OECD										
United States (50 states)	12.64	16.17	16.92	18.97	14.94	16.52	19.80	13.10	15.89	18.11
Canada	4.15	4.70	5.05	5.46	5.48	6.26	7.27	5.81	6.76	8.04
Mexico and Chile	2.94	2.41	2.93	3.07	2.04	3.32	3.65	2.23	3.79	4.18
OECD Europe[2]	3.88	3.18	3.35	3.22	2.61	2.98	3.05	2.57	3.19	3.18
Japan and South Korea	0.18	0.17	0.17	0.16	0.19	0.18	0.18	0.20	0.18	0.19
Australia and New Zealand	0.49	0.55	0.60	0.62	0.53	0.86	0.89	0.50	0.96	1.01
Total OECD production	**24.29**	**27.18**	**29.03**	**31.51**	**25.79**	**30.12**	**34.84**	**24.41**	**30.77**	**34.70**
Non-OECD										
Russia	10.50	10.63	10.71	10.97	10.80	11.22	11.58	11.35	12.16	12.67
Other Europe and Eurasia[3]	3.27	3.42	3.41	3.87	4.21	4.42	4.99	4.83	5.18	6.44
China	4.48	4.80	5.11	5.23	5.16	5.66	6.18	5.18	5.84	7.54
Other Asia[4]	3.82	3.72	3.85	3.80	3.54	3.67	3.80	3.73	4.01	4.06
Middle East	1.20	1.02	1.03	1.14	0.75	0.85	1.04	0.56	0.77	0.98
Africa	2.41	2.73	2.70	2.79	2.90	2.94	2.92	3.23	3.33	3.39
Brazil	2.73	3.62	3.70	4.01	4.68	5.43	6.05	4.96	6.12	8.34
Other Central and South America	2.21	2.51	2.71	2.59	2.53	2.97	3.25	3.13	3.47	4.70
Total non-OECD production	**30.63**	**32.44**	**33.21**	**34.41**	**34.57**	**37.17**	**39.80**	**36.96**	**40.88**	**48.10**
Total petroleum and other liquids production	**91.4**	**100.2**	**98.4**	**95.7**	**111.9**	**108.8**	**107.7**	**124.7**	**121.1**	**123.7**
OPEC market share (percent)	39.9	40.5	36.7	31.1	46.1	38.2	30.7	50.8	40.8	33.0

Table C6. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Selected world production subtotals:										
Crude oil and equivalents[6]	77.93	83.98	82.19	78.67	93.74	89.77	87.00	105.09	99.09	98.87
Tight oil	3.62	5.71	7.49	9.28	5.21	9.16	11.15	4.51	10.15	12.10
Bitumen[7]	2.11	2.91	3.00	3.31	3.57	3.95	4.72	3.86	4.26	5.36
Refinery processing gain[8]	2.40	2.45	2.42	2.26	2.80	2.74	2.50	3.20	2.97	2.89
Natural gas plant liquids	9.36	11.33	11.28	12.06	12.34	12.42	13.52	12.99	13.79	14.58
Liquids from renewable sources[9]	2.14	2.48	2.56	2.45	3.05	3.36	3.06	3.49	4.22	3.63
Liquids from coal[10]	0.21	0.30	0.33	0.53	0.30	0.69	1.40	0.30	1.05	3.16
Liquids from natural gas[11]	0.24	0.32	0.33	0.33	0.32	0.51	0.64	0.32	0.61	1.19
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01
Crude oil production[6]										
OPEC[5]										
Middle East	23.13	24.34	21.20	15.81	32.25	25.59	17.88	41.61	31.79	24.68
North Africa	2.43	3.19	2.93	2.63	3.61	2.92	2.65	4.06	2.96	2.71
West Africa	4.20	5.37	4.89	4.28	6.69	5.13	4.63	7.35	5.29	4.82
South America	2.82	3.34	2.86	2.54	4.23	2.98	2.55	5.25	3.48	2.80
Total OPEC production	**32.60**	**36.25**	**31.89**	**25.25**	**46.79**	**36.62**	**27.72**	**58.27**	**43.52**	**35.03**
Non-OPEC										
OECD										
United States (50 states)	8.90	10.93	11.58	13.36	9.63	11.01	13.47	8.09	10.41	10.94
Canada	3.42	4.01	4.35	4.76	4.76	5.48	6.50	5.08	5.92	7.24
Mexico and Chile	2.59	2.06	2.61	2.72	1.70	3.00	3.31	1.89	3.45	3.83
OECD Europe[2]	2.82	2.09	2.17	2.11	1.44	1.66	1.87	1.29	1.69	1.91
Japan and South Korea	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01
Australia and New Zealand	0.37	0.42	0.47	0.48	0.40	0.67	0.73	0.36	0.75	0.84
Total OECD production	**18.10**	**19.51**	**21.18**	**23.44**	**17.93**	**21.83**	**25.88**	**16.72**	**22.23**	**24.77**
Non-OECD										
Russia	10.02	10.03	10.15	10.38	9.95	10.42	10.72	10.07	11.10	11.37
Other Europe and Eurasia[3]	3.05	3.13	3.18	3.57	3.77	4.03	4.52	4.16	4.66	5.73
China	4.16	4.23	4.54	4.58	4.27	4.56	4.70	4.04	4.13	4.53
Other Asia[4]	3.04	2.81	2.94	2.89	2.46	2.45	2.64	2.41	2.47	2.66
Middle East	1.16	0.98	1.00	1.10	0.71	0.82	1.00	0.52	0.74	0.94
Africa	1.97	2.23	2.18	2.19	2.38	2.38	2.26	2.71	2.70	2.71
Brazil	2.02	2.75	2.87	3.14	3.42	4.16	4.78	3.55	4.60	6.93
Other Central and South America	1.81	2.06	2.25	2.14	2.05	2.49	2.77	2.65	2.94	4.21
Total non-OECD production	**27.24**	**28.22**	**29.11**	**29.98**	**29.03**	**31.32**	**33.40**	**30.10**	**33.35**	**39.07**
Total crude oil production[6]	**77.9**	**84.0**	**82.2**	**78.7**	**93.7**	**89.8**	**87.0**	**105.1**	**99.1**	**98.9**
OPEC market share (percent)	41.8	43.2	38.8	32.1	49.9	40.8	31.9	55.4	43.9	35.4

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. **2013 quantities and projections:** Energy Information Administration (EIA), AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A; and EIA, Generate World Oil Balance application.

High oil and gas resource case comparisons

Table D1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Production							
Crude oil and lease condensate	15.6	22.2	26.3	21.1	32.6	19.9	34.6
Natural gas plant liquids	3.6	5.5	6.3	5.7	7.9	5.5	9.0
Dry natural gas	25.1	29.6	33.1	33.9	43.8	36.4	52.0
Coal[1]	20.0	21.7	18.8	22.5	19.8	22.6	20.3
Nuclear / uranium[2]	8.3	8.4	8.4	8.5	8.5	8.7	8.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[3]	4.2	4.4	4.5	4.6	4.7	5.0	5.1
Other renewable energy[4]	2.3	3.2	3.2	3.6	3.4	4.6	3.6
Other[5]	1.3	0.9	0.9	0.9	1.0	1.0	1.0
Total	**82.7**	**98.7**	**104.3**	**103.7**	**124.4**	**106.6**	**136.8**
Imports							
Crude oil	17.0	13.6	13.5	15.7	11.7	18.2	11.3
Petroleum and other liquids[6]	4.3	4.6	4.4	4.4	4.7	4.1	4.4
Natural gas[7]	2.9	1.9	1.8	1.6	1.7	1.7	2.5
Other imports[8]	0.3	0.1	0.1	0.1	0.1	0.1	0.0
Total	**24.5**	**20.2**	**19.9**	**21.7**	**18.2**	**24.1**	**18.3**
Exports							
Petroleum and other liquids[9]	7.3	11.2	15.4	12.6	21.6	13.7	24.3
Natural gas[10]	1.6	4.5	4.6	6.4	10.8	7.4	15.7
Coal	2.9	2.5	2.5	3.3	3.4	3.5	4.0
Total	**11.7**	**18.1**	**22.5**	**22.4**	**35.7**	**24.6**	**44.0**
Discrepancy[11]	**-1.6**	**-0.1**	**-0.1**	**0.2**	**0.1**	**0.3**	**0.3**
Consumption							
Petroleum and other liquids[12]	35.9	37.1	37.5	36.5	37.8	36.2	37.5
Natural gas	26.9	26.8	30.1	28.8	34.4	30.5	38.4
Coal[13]	18.0	19.2	16.3	19.2	16.3	19.0	16.3
Nuclear / uranium[2]	8.3	8.4	8.4	8.5	8.5	8.7	8.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[14]	2.9	3.0	3.1	3.2	3.3	3.5	3.5
Other renewable energy[4]	2.3	3.2	3.2	3.6	3.4	4.6	3.6
Other[15]	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Total	**97.1**	**100.8**	**101.8**	**102.9**	**106.8**	**105.7**	**110.8**
Prices (2013 dollars per unit)							
Crude oil spot prices (dollars per barrel)							
Brent	109	79	76	106	98	141	129
West Texas Intermediate	98	73	64	99	84	136	115
Natural gas at Henry Hub (dollars per million Btu)	3.73	4.88	3.12	5.69	3.67	7.85	4.38
Coal (dollars per ton) at the minemouth[16]	37.2	37.9	37.2	43.7	42.3	49.2	47.8
Coal (dollars per million Btu) at the minemouth[16]	1.84	1.88	1.84	2.18	2.10	2.44	2.36
Average end-use[17]	2.50	2.54	2.43	2.84	2.66	3.09	2.88
Average electricity (cents per kilowatthour)	10.1	10.5	10.0	11.1	10.0	11.8	10.3

Table D1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Prices (nominal dollars per unit)							
Crude oil spot prices (dollars per barrel)							
Brent	109	90	85	142	127	229	205
West Texas Intermediate	98	83	72	133	109	220	182
Natural gas at Henry Hub							
(dollars per million Btu)	3.73	5.54	3.51	7.63	4.76	12.73	6.93
Coal (dollars per ton)							
at the minemouth[16]	37.2	43.0	41.7	58.6	54.8	79.8	75.6
Coal (dollars per million Btu)							
at the minemouth[16]	1.84	2.14	2.07	2.92	2.72	3.96	3.73
Average end-use[17]	2.50	2.88	2.73	3.81	3.45	5.00	4.56
Average electricity (cents per kilowatthour)	10.1	11.9	11.2	14.8	13.0	19.2	16.2

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2013 coal values: *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2013 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Energy consumption							
Residential							
Propane	0.43	0.32	0.33	0.28	0.28	0.25	0.25
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Distillate fuel oil	0.50	0.40	0.40	0.31	0.31	0.24	0.24
Petroleum and other liquids subtotal	0.93	0.73	0.74	0.59	0.60	0.49	0.49
Natural gas	5.05	4.63	4.75	4.52	4.70	4.31	4.52
Renewable energy[1]	0.58	0.41	0.41	0.38	0.37	0.35	0.35
Electricity	4.75	4.86	4.90	5.08	5.20	5.42	5.61
Delivered energy	**11.32**	**10.63**	**10.80**	**10.57**	**10.86**	**10.57**	**10.97**
Electricity related losses	9.79	9.75	9.53	9.91	9.76	10.33	10.20
Total	**21.10**	**20.38**	**20.33**	**20.48**	**20.62**	**20.91**	**21.17**
Commercial							
Propane	0.15	0.16	0.16	0.17	0.17	0.18	0.18
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.37	0.34	0.34	0.30	0.31	0.27	0.28
Residual fuel oil	0.03	0.07	0.07	0.07	0.07	0.06	0.07
Petroleum and other liquids subtotal	0.59	0.62	0.63	0.60	0.61	0.58	0.59
Natural gas	3.37	3.30	3.49	3.43	3.71	3.71	4.11
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.57	4.82	4.85	5.19	5.32	5.66	5.85
Delivered energy	**8.69**	**8.90**	**9.14**	**9.38**	**9.81**	**10.12**	**10.72**
Electricity related losses	9.42	9.68	9.44	10.13	9.99	10.80	10.64
Total	**18.10**	**18.58**	**18.58**	**19.52**	**19.81**	**20.92**	**21.37**
Industrial[4]							
Liquefied petroleum gases and other[5]	2.51	3.20	3.26	3.72	3.81	3.67	3.82
Motor gasoline[2]	0.25	0.26	0.27	0.25	0.29	0.25	0.29
Distillate fuel oil	1.31	1.42	1.41	1.36	1.46	1.35	1.48
Residual fuel oil	0.06	0.10	0.10	0.13	0.12	0.13	0.11
Petrochemical feedstocks	0.74	0.95	0.95	1.14	1.14	1.20	1.12
Other petroleum[6]	3.52	3.67	3.94	3.83	4.28	3.99	4.46
Petroleum and other liquids subtotal	8.40	9.61	9.94	10.44	11.09	10.59	11.29
Natural gas	7.62	8.33	8.56	8.65	9.17	8.90	9.43
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.87	2.02	2.10	3.05	2.29	3.84
Natural gas subtotal	9.14	10.20	10.58	10.75	12.21	11.19	13.28
Metallurgical coal	0.62	0.61	0.59	0.56	0.59	0.51	0.53
Other industrial coal	0.88	0.93	0.93	0.96	0.97	0.99	1.01
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	-0.03	-0.03	-0.06	-0.06
Coal subtotal	1.48	1.54	1.52	1.48	1.53	1.44	1.48
Biofuels heat and coproducts	0.72	0.80	0.81	0.80	0.82	0.86	0.88
Renewable energy[8]	1.48	1.53	1.56	1.59	1.64	1.63	1.70
Electricity	3.26	3.74	3.83	4.04	4.27	4.12	4.35
Delivered energy	**24.48**	**27.42**	**28.24**	**29.10**	**31.55**	**29.82**	**32.98**
Electricity related losses	6.72	7.51	7.45	7.88	8.01	7.85	7.92
Total	**31.20**	**34.93**	**35.69**	**36.98**	**39.56**	**37.68**	**40.90**

Table D2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Transportation							
Propane	0.05	0.04	0.04	0.05	0.05	0.07	0.07
Motor gasoline[2]	15.94	15.35	15.42	13.30	13.56	12.55	12.83
of which: E85[9]	0.02	0.03	0.03	0.20	0.17	0.28	0.28
Jet fuel[10]	2.80	3.01	3.01	3.40	3.42	3.64	3.65
Distillate fuel oil[11]	6.50	7.35	7.42	7.76	8.22	7.97	8.33
Residual fuel oil	0.57	0.35	0.35	0.36	0.36	0.36	0.36
Other petroleum[12]	0.15	0.16	0.16	0.16	0.16	0.16	0.16
Petroleum and other liquids subtotal	26.00	26.27	26.42	25.03	25.77	24.76	25.42
Pipeline fuel natural gas	0.88	0.85	0.93	0.94	1.13	0.96	1.26
Compressed / liquefied natural gas	0.05	0.07	0.07	0.17	0.18	0.71	0.96
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.04	0.04	0.06	0.06
Delivered energy	**26.96**	**27.22**	**27.44**	**26.18**	**27.12**	**26.49**	**27.70**
Electricity related losses	0.05	0.06	0.06	0.08	0.08	0.12	0.11
Total	**27.01**	**27.29**	**27.50**	**26.27**	**27.20**	**26.61**	**27.81**
Unspecified sector[13]	**-0.27**	**-0.34**	**-0.34**	**-0.37**	**-0.41**	**-0.38**	**-0.41**
Delivered energy consumption for all sectors							
Liquefied petroleum gases and other[5]	3.14	3.73	3.80	4.23	4.31	4.17	4.33
Motor gasoline[2]	16.36	15.79	15.87	13.72	14.01	12.96	13.28
of which: E85[9]	0.02	0.03	0.03	0.20	0.17	0.28	0.28
Jet fuel[10]	2.97	3.20	3.20	3.61	3.63	3.86	3.88
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.10	8.86	8.92	9.05	9.57	9.13	9.60
Residual fuel oil	0.65	0.53	0.53	0.56	0.55	0.56	0.54
Petrochemical feedstocks	0.74	0.95	0.95	1.14	1.14	1.20	1.12
Other petroleum[14]	3.67	3.82	4.10	3.98	4.44	4.15	4.62
Petroleum and other liquids subtotal	35.65	36.89	37.38	36.30	37.66	36.03	37.38
Natural gas	16.10	16.32	16.86	16.76	17.75	17.64	19.03
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.87	2.02	2.10	3.05	2.29	3.84
Pipeline natural gas	0.88	0.85	0.93	0.94	1.13	0.96	1.26
Natural gas subtotal	18.50	19.05	19.81	19.80	21.93	20.88	24.13
Metallurgical coal	0.62	0.61	0.59	0.56	0.59	0.51	0.53
Other coal	0.92	0.98	0.98	1.00	1.01	1.04	1.05
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	-0.03	-0.03	-0.06	-0.06
Coal subtotal	1.52	1.59	1.57	1.53	1.57	1.49	1.53
Biofuels heat and coproducts	0.72	0.80	0.81	0.80	0.82	0.86	0.88
Renewable energy[15]	2.18	2.06	2.09	2.09	2.13	2.10	2.17
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.60	13.45	13.62	14.35	14.83	15.25	15.87
Delivered energy	**71.17**	**73.84**	**75.27**	**74.87**	**78.94**	**76.62**	**81.97**
Electricity related losses	25.97	27.00	26.48	28.01	27.83	29.10	28.87
Total	**97.14**	**100.84**	**101.75**	**102.87**	**106.78**	**105.73**	**110.84**
Electric power[16]							
Distillate fuel oil	0.05	0.09	0.08	0.08	0.07	0.08	0.07
Residual fuel oil	0.21	0.08	0.09	0.09	0.09	0.09	0.10
Petroleum and other liquids subtotal	0.26	0.17	0.16	0.17	0.16	0.18	0.17
Natural gas	8.36	7.80	10.29	9.03	12.46	9.61	14.24
Steam coal	16.49	17.59	14.77	17.63	14.78	17.52	14.76
Nuclear / uranium[17]	8.27	8.42	8.42	8.47	8.46	8.73	8.46
Renewable energy[18]	4.78	6.13	6.11	6.72	6.50	7.99	6.82
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.10	0.08	0.11	0.07
Total	**38.57**	**40.45**	**40.10**	**42.35**	**42.67**	**44.36**	**44.74**

Table D2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Total energy consumption							
Liquefied petroleum gases and other[5]	3.14	3.73	3.80	4.23	4.31	4.17	4.33
Motor gasoline[2]	16.36	15.79	15.87	13.72	14.01	12.96	13.28
of which: E85[9]	0.02	0.03	0.03	0.20	0.17	0.28	0.28
Jet fuel[10]	2.97	3.20	3.20	3.61	3.63	3.86	3.88
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.15	8.95	9.00	9.13	9.65	9.21	9.67
Residual fuel oil	0.87	0.61	0.61	0.64	0.64	0.65	0.64
Petrochemical feedstocks	0.74	0.95	0.95	1.14	1.14	1.20	1.12
Other petroleum[14]	3.67	3.82	4.10	3.98	4.44	4.15	4.62
Petroleum and other liquids subtotal	35.91	37.06	37.54	36.47	37.82	36.21	37.54
Natural gas	24.46	24.12	27.15	25.79	30.21	27.25	33.27
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.87	2.02	2.10	3.05	2.29	3.84
Pipeline natural gas	0.88	0.85	0.93	0.94	1.13	0.96	1.26
Natural gas subtotal	26.86	26.85	30.10	28.83	34.39	30.50	38.37
Metallurgical coal	0.62	0.61	0.59	0.56	0.59	0.51	0.53
Other coal	17.41	18.57	15.75	18.63	15.79	18.56	15.81
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	-0.03	-0.03	-0.06	-0.06
Coal subtotal	18.01	19.18	16.34	19.16	16.35	19.01	16.29
Nuclear / uranium[17]	8.27	8.42	8.42	8.47	8.46	8.73	8.46
Biofuels heat and coproducts	0.72	0.80	0.81	0.80	0.82	0.86	0.88
Renewable energy[19]	6.96	8.19	8.20	8.81	8.63	10.09	8.99
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.10	0.08	0.11	0.07
Total	**97.14**	**100.84**	**101.75**	**102.87**	**106.78**	**105.73**	**110.84**
Energy use and related statistics							
Delivered energy use	71.17	73.84	75.27	74.87	78.94	76.62	81.97
Total energy use	97.14	100.84	101.75	102.87	106.78	105.73	110.84
Ethanol consumed in motor gasoline and E85	1.12	1.12	1.13	1.12	1.13	1.27	1.30
Population (millions)	317	334	334	359	359	380	380
Gross domestic product (billion 2009 dollars)	15,710	18,801	18,841	23,894	24,222	29,898	30,236
Carbon dioxide emissions (million metric tons)	5,405	5,499	5,435	5,514	5,636	5,549	5,800

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE-EIA-0035(2014/11) (Washington, DC, November 2014). 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D3. Energy prices by sector and source
(2013 dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Residential							
Propane	23.3	23.0	22.2	24.4	23.9	26.6	25.6
Distillate fuel oil	27.2	21.5	20.9	26.3	24.9	32.9	31.3
Natural gas	10.0	11.6	9.6	12.8	10.4	15.5	11.9
Electricity	35.6	37.8	36.1	40.0	36.9	42.4	37.6
Commercial							
Propane	20.0	19.4	18.5	21.1	20.4	23.9	22.6
Distillate fuel oil	26.7	21.0	20.3	25.8	24.3	32.5	31.0
Residual fuel oil	22.1	14.2	13.5	18.1	16.7	24.3	22.1
Natural gas	8.1	9.6	7.6	10.4	8.1	12.6	9.0
Electricity	29.7	31.1	29.6	32.6	29.4	34.5	29.8
Industrial[1]							
Propane	20.3	19.6	18.7	21.5	20.8	24.5	23.0
Distillate fuel oil	27.3	21.2	20.5	26.1	24.5	32.7	31.3
Residual fuel oil	20.0	13.3	12.6	17.2	15.7	23.5	21.1
Natural gas[2]	4.6	6.2	4.3	6.8	4.6	8.8	5.2
Metallurgical coal	5.5	5.8	5.8	6.7	6.6	7.2	7.1
Other industrial coal	3.2	3.3	3.2	3.6	3.4	3.9	3.7
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	20.2	21.3	19.9	22.6	20.0	24.7	20.7
Transportation							
Propane	24.6	24.0	23.3	25.5	24.9	27.6	26.6
E85[3]	33.1	30.4	29.9	31.2	30.2	35.4	34.5
Motor gasoline[4]	29.3	22.5	21.8	26.4	25.0	32.3	31.2
Jet fuel[5]	21.8	16.1	15.5	21.3	19.4	28.3	26.1
Diesel fuel (distillate fuel oil)[6]	28.2	23.1	22.5	28.0	26.4	34.7	33.2
Residual fuel oil	19.3	11.7	11.1	15.4	14.1	20.3	19.0
Natural gas[7]	17.6	17.8	16.0	15.7	13.9	19.6	16.8
Electricity	28.5	30.2	28.2	32.9	28.9	36.0	30.5
Electric power[8]							
Distillate fuel oil	24.0	18.8	18.1	23.6	22.1	30.2	28.7
Residual fuel oil	18.9	11.5	10.7	15.4	14.0	21.6	19.3
Natural gas	4.4	5.4	3.7	6.2	4.1	8.3	4.7
Steam coal	2.3	2.4	2.2	2.7	2.4	2.9	2.7
Average price to all users[9]							
Propane	21.9	21.1	20.2	22.6	21.9	25.2	23.9
E85[3]	33.1	30.4	29.9	31.2	30.2	35.4	34.5
Motor gasoline[4]	29.0	22.5	21.8	26.4	25.0	32.3	31.2
Jet fuel[5]	21.8	16.1	15.5	21.3	19.4	28.3	26.1
Distillate fuel oil	27.9	22.6	22.0	27.6	26.0	34.2	32.8
Residual fuel oil	19.4	12.2	11.6	16.0	14.7	21.5	19.8
Natural gas	6.1	7.5	5.4	8.2	5.8	10.5	6.7
Metallurgical coal	5.5	5.8	5.8	6.7	6.6	7.2	7.1
Other coal	2.4	2.4	2.3	2.7	2.5	3.0	2.7
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	29.5	30.8	29.2	32.4	29.3	34.7	30.1
Non-renewable energy expenditures by sector (billion 2013 dollars)							
Residential	243	254	238	276	256	311	278
Commercial	177	194	182	219	200	259	228
Industrial[1]	224	264	242	323	298	389	348
Transportation	719	565	550	638	619	791	781
Total non-renewable expenditures	1,364	1,276	1,213	1,456	1,373	1,751	1,635
Transportation renewable expenditures	1	1	1	6	5	10	10
Total expenditures	**1,364**	**1,277**	**1,214**	**1,462**	**1,378**	**1,761**	**1,645**

Table D3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Residential							
Propane	23.3	26.1	25.0	32.8	31.0	43.1	40.4
Distillate fuel oil	27.2	24.4	23.4	35.3	32.3	53.3	49.5
Natural gas	10.0	13.2	10.8	17.1	13.5	25.1	18.8
Electricity	35.6	42.9	40.5	53.6	47.9	68.8	59.4
Commercial							
Propane	20.0	22.0	20.7	28.3	26.5	38.8	35.7
Distillate fuel oil	26.7	23.8	22.8	34.6	31.5	52.6	49.1
Residual fuel oil	22.1	16.1	15.1	24.3	21.7	39.4	34.9
Natural gas	8.1	10.8	8.5	13.9	10.5	20.5	14.2
Electricity	29.7	35.3	33.2	43.7	38.1	56.0	47.1
Industrial[1]							
Propane	20.3	22.3	21.0	28.8	26.9	39.7	36.4
Distillate fuel oil	27.3	24.1	23.0	35.0	31.8	53.0	49.4
Residual fuel oil	20.0	15.1	14.2	23.1	20.4	38.0	33.4
Natural gas[2]	4.6	7.0	4.8	9.1	6.0	14.2	8.3
Metallurgical coal	5.5	6.6	6.5	8.9	8.5	11.6	11.2
Other industrial coal	3.2	3.8	3.6	4.8	4.5	6.3	5.9
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	20.2	24.2	22.3	30.3	26.0	40.0	32.7
Transportation							
Propane	24.6	27.2	26.1	34.1	32.3	44.8	42.0
E85[3]	33.1	34.4	33.5	41.9	39.3	57.4	54.6
Motor gasoline[4]	29.3	25.5	24.5	35.3	32.4	52.4	49.4
Jet fuel[5]	21.8	18.3	17.3	28.6	25.2	45.8	41.2
Diesel fuel (distillate fuel oil)[6]	28.2	26.2	25.2	37.6	34.3	56.2	52.5
Residual fuel oil	19.3	13.2	12.4	20.6	18.4	32.9	30.1
Natural gas[7]	17.6	20.2	18.0	21.0	18.0	31.8	26.5
Electricity	28.5	34.3	31.7	44.1	37.5	58.4	48.2
Electric power[8]							
Distillate fuel oil	24.0	21.3	20.3	31.7	28.7	49.0	45.4
Residual fuel oil	18.9	13.0	12.0	20.6	18.2	35.0	30.6
Natural gas	4.4	6.1	4.1	8.3	5.4	13.4	7.4
Steam coal	2.3	2.7	2.5	3.6	3.2	4.7	4.2

Table D3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Average price to all users[9]							
Propane	21.9	23.9	22.6	30.3	28.4	40.9	37.7
E85[3]	33.1	34.4	33.5	41.9	39.3	57.4	54.6
Motor gasoline[4]	29.0	25.5	24.5	35.3	32.4	52.4	49.4
Jet fuel[5]	21.8	18.3	17.3	28.6	25.2	45.8	41.2
Distillate fuel oil	27.9	25.7	24.6	36.9	33.7	55.5	51.9
Residual fuel oil	19.4	13.8	13.0	21.5	19.1	34.8	31.2
Natural gas	6.1	8.5	6.1	11.0	7.5	17.0	10.6
Metallurgical coal	5.5	6.6	6.5	8.9	8.5	11.6	11.2
Other coal	2.4	2.8	2.6	3.7	3.3	4.8	4.3
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	29.5	34.9	32.8	43.4	38.1	56.2	47.5
Non-renewable energy expenditures by sector (billion nominal dollars)							
Residential	243	288	268	370	332	504	440
Commercial	177	220	205	294	260	420	360
Industrial[1]	224	299	272	433	387	631	551
Transportation	719	641	617	855	803	1,283	1,235
Total non-renewable expenditures	1,364	1,448	1,361	1,952	1,782	2,839	2,586
Transportation renewable expenditures	1	1	1	8	7	16	15
Total expenditures	**1,364**	**1,449**	**1,362**	**1,960**	**1,788**	**2,855**	**2,601**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 transportation sector natural gas delivered prices are model results. 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D4. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil							
Domestic crude production[1]	7.44	10.60	12.61	10.04	15.64	9.43	16.59
Alaska	0.52	0.42	0.42	0.24	0.24	0.34	0.14
Lower 48 states	6.92	10.18	12.19	9.80	15.40	9.09	16.45
Net imports	7.60	5.51	5.16	6.44	4.02	7.58	4.08
Gross imports	7.73	6.14	6.03	7.07	5.18	8.21	5.02
Exports	0.13	0.63	0.87	0.63	1.16	0.63	0.94
Other crude supply[2]	0.27	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**15.30**	**16.11**	**17.77**	**16.48**	**19.66**	**17.01**	**20.67**
Net product imports	-1.37	-2.80	-5.03	-3.56	-7.86	-4.26	-9.89
Gross refined product imports[3]	0.82	1.21	1.03	1.31	1.27	1.26	1.12
Unfinished oil imports	0.66	0.60	0.60	0.52	0.52	0.45	0.45
Blending component imports	0.60	0.59	0.58	0.49	0.57	0.40	0.52
Exports	3.43	5.20	7.24	5.89	10.22	6.36	11.97
Refinery processing gain[4]	1.09	0.98	1.14	0.97	1.10	0.98	1.06
Product stock withdrawal	0.11	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas plant liquids	2.61	4.04	4.65	4.19	5.78	4.07	6.59
Supply from renewable sources	0.93	1.01	1.02	1.01	1.01	1.12	1.14
Ethanol	0.83	0.84	0.85	0.84	0.84	0.95	0.97
Domestic production	0.85	0.86	0.87	0.86	0.88	0.93	0.96
Net imports	-0.02	-0.02	-0.03	-0.02	-0.03	0.02	0.02
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.10	0.14	0.14	0.11	0.09	0.11	0.09
Domestic production	0.09	0.13	0.13	0.10	0.08	0.10	0.08
Net imports	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other biomass-derived liquids[5]	0.00	0.03	0.03	0.06	0.08	0.06	0.08
Domestic production	0.00	0.03	0.03	0.06	0.08	0.06	0.08
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other[6]	0.21	0.28	0.30	0.30	0.34	0.32	0.34
Total primary supply[7]	**18.87**	**19.62**	**19.84**	**19.38**	**20.03**	**19.24**	**19.90**
Product supplied							
by fuel							
Liquefied petroleum gases and other[8]	2.50	2.91	2.95	3.30	3.38	3.25	3.39
Motor gasoline[9]	8.85	8.49	8.53	7.41	7.56	7.05	7.22
of which: E85[10]	0.01	0.02	0.02	0.13	0.12	0.19	0.19
Jet fuel[11]	1.43	1.55	1.55	1.75	1.76	1.87	1.88
Distillate fuel oil[12]	3.83	4.26	4.28	4.34	4.59	4.38	4.60
of which: Diesel	3.56	3.94	3.97	4.09	4.33	4.17	4.38
Residual fuel oil	0.32	0.27	0.27	0.28	0.28	0.28	0.28
Other[13]	2.04	2.18	2.29	2.33	2.53	2.43	2.60
by sector							
Residential and commercial	0.86	0.76	0.76	0.67	0.68	0.61	0.62
Industrial[14]	4.69	5.50	5.65	6.04	6.37	6.09	6.47
Transportation	13.36	13.46	13.54	12.79	13.15	12.66	13.00
Electric power[15]	0.12	0.08	0.07	0.08	0.07	0.08	0.08
Unspecified sector[16]	-0.12	-0.15	-0.15	-0.17	-0.19	-0.17	-0.19
Total product supplied	**18.96**	**19.65**	**19.87**	**19.41**	**20.09**	**19.27**	**19.97**
Discrepancy[17]	-0.10	-0.03	-0.03	-0.03	-0.06	-0.03	-0.07

Table D4. Petroleum and other liquids supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Domestic refinery distillation capacity[18]	17.8	18.8	19.0	18.8	20.1	18.8	20.9
Capacity utilization rate (percent)[19]	88.3	87.8	95.6	89.4	99.8	92.0	100.4
Net import share of product supplied (percent)	33.0	13.7	0.6	14.8	-19.3	17.4	-29.1
Net expenditures for imported crude oil and petroleum products (billion 2013 dollars)	308	167	153	259	165	405	214

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). Other 2013 data: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D5. Petroleum and other liquids prices
(2013 dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil prices (2013 dollars per barrel)							
Brent spot	109	79	76	106	98	141	129
West Texas Intermediate spot	98	73	64	99	84	136	115
Average imported refiners acquisition cost[1]	98	71	66	96	82	131	111
Brent / West Texas Intermediate spread	10.7	6.2	11.3	6.2	14.1	5.6	14.1
Delivered sector product prices							
Residential							
Propane	2.13	2.10	2.03	2.23	2.18	2.43	2.33
Distillate fuel oil	3.78	2.99	2.89	3.65	3.45	4.56	4.34
Commercial							
Distillate fuel oil	3.68	2.89	2.80	3.56	3.35	4.47	4.28
Residual fuel oil	3.31	2.12	2.02	2.71	2.50	3.64	3.31
Residual fuel oil (2013 dollars per barrel)	139	89	85	114	105	153	139
Industrial[2]							
Propane	1.85	1.79	1.70	1.96	1.90	2.24	2.10
Distillate fuel oil	3.75	2.91	2.82	3.58	3.36	4.49	4.29
Residual fuel oil	3.00	2.00	1.89	2.58	2.36	3.51	3.16
Residual fuel oil (2013 dollars per barrel)	126	84	79	108	99	147	133
Transportation							
Propane	2.24	2.19	2.12	2.32	2.27	2.52	2.43
E85[3]	3.14	2.90	2.85	2.98	2.88	3.38	3.29
Ethanol wholesale price	2.37	2.49	2.42	2.35	2.28	2.64	2.53
Motor gasoline[4]	3.55	2.74	2.65	3.20	3.03	3.90	3.77
Jet fuel[5]	2.94	2.17	2.09	2.88	2.62	3.81	3.52
Diesel fuel (distillate fuel oil)[6]	3.86	3.17	3.08	3.84	3.62	4.75	4.55
Residual fuel oil	2.89	1.74	1.66	2.30	2.12	3.03	2.85
Residual fuel oil (2013 dollars per barrel)	122	73	70	97	89	127	120
Electric power[7]							
Distillate fuel oil	3.33	2.60	2.51	3.28	3.07	4.19	3.98
Residual fuel oil	2.83	1.71	1.61	2.30	2.09	3.23	2.90
Residual fuel oil (2013 dollars per barrel)	119	72	67	97	88	136	122
Average prices, all sectors[8]							
Propane	2.00	1.93	1.84	2.06	2.00	2.30	2.18
Motor gasoline[4]	3.53	2.74	2.65	3.20	3.03	3.90	3.77
Jet fuel[5]	2.94	2.17	2.09	2.88	2.62	3.81	3.52
Distillate fuel oil	3.83	3.11	3.01	3.78	3.57	4.69	4.50
Residual fuel oil	2.90	1.83	1.73	2.40	2.20	3.22	2.96
Residual fuel oil (2013 dollars per barrel)	122	77	73	101	92	135	124
Average	**3.16**	**2.46**	**2.37**	**2.89**	**2.73**	**3.62**	**3.44**

Table D5. Petroleum and other liquids prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil prices (nominal dollars per barrel)							
Brent spot	109	90	85	142	127	229	205
West Texas Intermediate spot	98	83	72	133	109	220	182
Average imported refiners acquisition cost[1]	98	80	74	129	107	212	175
Delivered sector product prices							
Residential							
Propane	2.13	2.38	2.28	2.99	2.83	3.94	3.69
Distillate fuel oil	3.78	3.39	3.25	4.90	4.48	7.40	6.87
Commercial							
Distillate fuel oil	3.68	3.28	3.14	4.78	4.35	7.25	6.76
Residual fuel oil	3.31	2.41	2.26	3.63	3.25	5.90	5.23
Industrial[2]							
Propane	1.85	2.04	1.91	2.63	2.46	3.62	3.33
Distillate fuel oil	3.75	3.30	3.16	4.80	4.37	7.28	6.78
Residual fuel oil	3.00	2.26	2.12	3.46	3.06	5.69	4.99
Transportation							
Propane	2.24	2.49	2.38	3.12	2.95	4.09	3.84
E85[3]	3.14	3.29	3.20	3.99	3.74	5.48	5.21
Ethanol wholesale price	2.37	2.83	2.72	3.15	2.96	4.27	4.00
Motor gasoline[4]	3.55	3.10	2.98	4.29	3.93	6.32	5.96
Jet fuel[5]	2.94	2.47	2.34	3.86	3.40	6.18	5.57
Diesel fuel (distillate fuel oil)[6]	3.86	3.60	3.45	5.15	4.70	7.70	7.20
Residual fuel oil	2.89	1.98	1.86	3.08	2.75	4.92	4.50
Electric power[7]							
Distillate fuel oil	3.33	2.95	2.82	4.39	3.98	6.79	6.30
Residual fuel oil	2.83	1.94	1.80	3.09	2.72	5.24	4.58
Average prices, all sectors[8]							
Propane	2.00	2.19	2.07	2.77	2.59	3.73	3.45
Motor gasoline[4]	3.53	3.10	2.98	4.29	3.93	6.32	5.95
Jet fuel[5]	2.94	2.47	2.34	3.86	3.40	6.18	5.57
Distillate fuel oil	3.83	3.52	3.38	5.07	4.63	7.61	7.12
Residual fuel oil (nominal dollars per barrel)	122	87	82	135	120	219	196
Average	**3.16**	**2.79**	**2.66**	**3.88**	**3.54**	**5.86**	**5.43**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2013 average imported crude oil price: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2013 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2013 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D6. Natural gas supply, disposition, and prices
(trillion cubic feet, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Supply							
Dry gas production[1]	24.40	28.82	32.18	33.01	42.66	35.45	50.61
Supplemental natural gas[2]	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	1.29	-2.55	-2.74	-4.81	-9.03	-5.62	-13.11
Pipeline[3]	1.20	-0.48	-0.66	-1.52	-1.78	-2.33	-2.85
Liquefied natural gas	0.09	-2.08	-2.08	-3.29	-7.26	-3.29	-10.26
Total supply	**25.75**	**26.33**	**29.51**	**28.27**	**33.69**	**29.90**	**37.57**
Consumption by sector							
Residential	4.92	4.50	4.62	4.40	4.57	4.20	4.40
Commercial	3.28	3.21	3.39	3.33	3.61	3.61	4.00
Industrial[4]	7.41	8.10	8.32	8.41	8.92	8.66	9.18
Natural gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas-to-liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric power[7]	8.16	7.61	10.04	8.81	12.16	9.38	13.89
Transportation[8]	0.05	0.07	0.07	0.17	0.18	0.70	0.94
Pipeline fuel	0.86	0.83	0.90	0.91	1.10	0.93	1.22
Lease and plant fuel[9]	1.48	1.82	1.97	2.05	2.97	2.23	3.74
Total consumption	**26.16**	**26.14**	**29.32**	**28.08**	**33.50**	**29.70**	**37.38**
Discrepancy[10]	**-0.41**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Natural gas spot price at Henry Hub							
(2013 dollars per million Btu)	3.73	4.88	3.12	5.69	3.67	7.85	4.38
(nominal dollars per million Btu)	3.73	5.54	3.51	7.63	4.76	12.73	6.93
Delivered prices							
(2013 dollars per thousand cubic feet)							
Residential	10.29	11.92	9.90	13.15	10.72	15.90	12.21
Commercial	8.35	9.82	7.83	10.69	8.31	12.97	9.24
Industrial[4]	4.68	6.35	4.40	6.99	4.78	9.03	5.37
Electric power[7]	4.51	5.52	3.77	6.38	4.25	8.49	4.79
Transportation[11]	18.13	18.27	16.49	16.13	14.27	20.18	17.24
Average[12]	**6.32**	**7.66**	**5.59**	**8.40**	**5.97**	**10.76**	**6.87**
(nominal dollars per thousand cubic feet)							
Residential	10.29	13.52	11.11	17.62	13.91	25.77	19.31
Commercial	8.35	11.14	8.79	14.33	10.78	21.03	14.61
Industrial[4]	4.68	7.20	4.94	9.37	6.20	14.64	8.49
Electric power[7]	4.51	6.26	4.24	8.55	5.52	13.76	7.57
Transportation[11]	18.13	20.73	18.51	21.62	18.52	32.72	27.26
Average[12]	**6.32**	**8.68**	**6.28**	**11.27**	**7.75**	**17.44**	**10.87**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes use for lease and plant fuel.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as fuel in motor vehicles, trains, and ships.
[9]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2013 values include net storage injections.
[11]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[12]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2013 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2013 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 transportation sector delivered prices are model results. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D7. Oil and gas supply

Production and supply	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil							
Lower 48 average wellhead price[1] (2013 dollars per barrel)	**97**	**75**	**67**	**101**	**85**	**136**	**117**
Production (million barrels per day)[2]							
United States total	7.44	10.60	12.61	10.04	15.64	9.43	16.59
Lower 48 onshore	5.57	8.03	9.88	7.60	13.03	6.92	14.03
Tight oil[3]	3.15	5.60	7.45	4.83	10.23	4.29	11.56
Carbon dioxide enhanced oil recovery	0.28	0.35	0.32	0.58	0.46	0.83	0.44
Other	2.14	2.08	2.12	2.19	2.34	1.80	2.03
Lower 48 offshore	1.36	2.15	2.31	2.21	2.37	2.17	2.42
State	0.07	0.05	0.05	0.03	0.03	0.02	0.02
Federal	1.29	2.10	2.26	2.18	2.34	2.14	2.39
Alaska	0.52	0.42	0.42	0.24	0.24	0.34	0.14
Onshore	0.45	0.30	0.30	0.18	0.18	0.12	0.12
State offshore	0.06	0.12	0.12	0.06	0.06	0.02	0.02
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.20	0.00
Lower 48 end of year reserves[2] (billion barrels)	**29.4**	**37.4**	**40.6**	**42.6**	**55.2**	**44.8**	**62.7**
Natural gas plant liquids production (million barrels per day)							
United States total	2.61	4.04	4.65	4.20	5.78	4.07	6.59
Lower 48 onshore	2.39	3.82	4.42	3.92	5.50	3.79	6.31
Lower 48 offshore	0.18	0.19	0.20	0.26	0.26	0.26	0.27
Alaska	0.03	0.02	0.02	0.01	0.01	0.02	0.01
Natural gas							
Natural gas spot price at Henry Hub (2013 dollars per million Btu)	**3.73**	**4.88**	**3.12**	**5.69**	**3.67**	**7.85**	**4.38**
Dry production (trillion cubic feet)[4]							
United States total	24.40	28.82	32.18	33.01	42.66	35.45	50.61
Lower 48 onshore	22.63	26.52	29.78	29.05	39.66	31.49	47.47
Tight gas	4.38	5.21	5.44	5.99	7.06	6.97	8.14
Shale gas and tight oil plays[3]	11.34	15.44	18.82	17.85	27.50	19.58	34.57
Coalbed methane	1.29	1.45	1.25	1.24	1.16	1.25	1.13
Other	5.61	4.42	4.27	3.97	3.95	3.69	3.63
Lower 48 offshore	1.46	2.03	2.14	2.79	2.77	2.81	2.95
State	0.11	0.06	0.06	0.03	0.03	0.02	0.02
Federal	1.35	1.98	2.08	2.76	2.74	2.79	2.93
Alaska	0.32	0.27	0.27	1.18	0.23	1.15	0.19
Onshore	0.32	0.27	0.27	1.18	0.23	1.15	0.19
State offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**293**	**309**	**329**	**329**	**382**	**345**	**435**
Supplemental gas supplies (trillion cubic feet)[5]	**0.05**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total lower 48 wells drilled (thousands)	**44.5**	**43.4**	**47.1**	**52.1**	**62.3**	**56.7**	**61.5**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2013 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2013 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D8. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil spot prices							
(2013 dollars per barrel)							
Brent	109	79	76	106	98	141	129
West Texas Intermediate	98	73	64	99	84	136	115
(nominal dollars per barrel)							
Brent	109	90	85	142	127	229	205
West Texas Intermediate	98	83	72	133	109	220	182
Petroleum and other liquids consumption[1]							
OECD							
United States (50 states)	18.96	19.65	19.87	19.41	20.09	19.27	19.97
United States territories	0.30	0.31	0.31	0.34	0.34	0.38	0.38
Canada	2.29	2.31	2.31	2.21	2.21	2.14	2.14
Mexico and Chile	2.46	2.71	2.71	2.80	2.80	2.92	2.92
OECD Europe[2]	13.96	14.20	14.20	14.09	14.09	14.12	14.12
Japan	4.56	4.27	4.27	4.03	4.03	3.65	3.65
South Korea	2.43	2.58	2.58	2.53	2.53	2.40	2.40
Australia and New Zealand	1.16	1.16	1.16	1.11	1.11	1.15	1.15
Total OECD consumption	**46.14**	**47.20**	**47.43**	**46.52**	**47.20**	**46.04**	**46.74**
Non-OECD							
Russia	3.30	3.31	3.31	3.23	3.23	3.01	3.01
Other Europe and Eurasia[3]	2.06	2.22	2.22	2.39	2.39	2.59	2.59
China	10.67	13.13	13.13	17.03	17.03	20.19	20.19
India	3.70	4.30	4.30	5.52	5.52	6.79	6.79
Other Asia[4]	7.37	9.08	9.08	12.35	12.35	16.49	16.49
Middle East	7.61	8.40	8.40	9.56	9.56	11.13	11.13
Africa	3.42	3.93	3.93	4.78	4.78	6.18	6.18
Brazil	3.11	3.33	3.33	3.74	3.74	4.50	4.50
Other Central and South America	3.38	3.49	3.49	3.72	3.72	4.15	4.15
Total non-OECD consumption	**44.60**	**51.20**	**51.20**	**62.31**	**62.31**	**75.01**	**75.01**
Total consumption	**90.7**	**98.4**	**98.6**	**108.8**	**109.5**	**121.0**	**121.8**
Petroleum and other liquids production							
OPEC[5]							
Middle East	26.32	24.56	21.99	29.34	22.69	36.14	27.03
North Africa	2.90	3.51	3.51	3.67	3.67	4.06	4.06
West Africa	4.26	5.00	5.00	5.24	5.24	5.43	5.43
South America	3.01	3.10	3.10	3.27	3.27	3.79	3.79
Total OPEC production	**36.49**	**36.16**	**33.59**	**41.53**	**34.87**	**49.42**	**40.31**
Non-OPEC							
OECD							
United States (50 states)	12.64	16.92	19.73	16.52	23.89	15.89	25.69
Canada	4.15	5.05	5.05	6.26	6.26	6.76	6.76
Mexico and Chile	2.94	2.93	2.93	3.32	3.32	3.79	3.79
OECD Europe[2]	3.88	3.35	3.35	2.98	2.98	3.19	3.19
Japan and South Korea	0.18	0.17	0.17	0.18	0.18	0.18	0.18
Australia and New Zealand	0.49	0.60	0.60	0.86	0.86	0.96	0.96
Total OECD production	**24.29**	**29.03**	**31.83**	**30.12**	**37.49**	**30.77**	**40.57**
Non-OECD							
Russia	10.50	10.71	10.71	11.22	11.22	12.16	12.16
Other Europe and Eurasia[3]	3.27	3.41	3.41	4.42	4.42	5.18	5.18
China	4.48	5.11	5.11	5.66	5.66	5.84	5.84
Other Asia[4]	3.82	3.85	3.85	3.67	3.67	4.01	4.01
Middle East	1.20	1.03	1.03	0.85	0.85	0.77	0.77
Africa	2.41	2.70	2.70	2.94	2.94	3.33	3.33
Brazil	2.73	3.70	3.70	5.43	5.43	6.12	6.12
Other Central and South America	2.21	2.71	2.71	2.97	2.97	3.47	3.47
Total non-OECD production	**30.63**	**33.21**	**33.21**	**37.17**	**37.17**	**40.88**	**40.88**
Total petroleum and other liquids production	**91.4**	**98.4**	**98.6**	**108.8**	**109.5**	**121.1**	**121.8**
OPEC market share (percent)	39.9	36.7	34.1	38.2	31.8	40.8	33.1

Table D8. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Selected world production subtotals:							
Crude oil and equivalents[6]	77.93	82.19	81.78	89.77	88.84	99.09	97.22
Tight oil	3.62	7.49	9.33	9.16	14.57	10.15	17.40
Bitumen[7]	2.11	3.00	3.00	3.95	3.95	4.26	4.26
Refinery processing gain[8]	2.40	2.42	2.59	2.74	2.88	2.97	3.04
Natural gas plant liquids	9.36	11.28	11.89	12.42	13.99	13.79	16.31
Liquids from renewable sources[9]	2.14	2.56	2.57	3.36	3.38	4.22	4.24
Liquids from coal[10]	0.21	0.33	0.33	0.69	0.69	1.05	1.05
Liquids from natural gas[11]	0.24	0.33	0.33	0.51	0.51	0.61	0.61
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.14	0.01	0.14
Crude oil production[6]							
OPEC[5]							
Middle East	23.13	21.20	18.63	25.59	18.93	31.79	22.68
North Africa	2.43	2.93	2.93	2.92	2.92	2.96	2.96
West Africa	4.20	4.89	4.89	5.13	5.13	5.29	5.29
South America	2.82	2.86	2.86	2.98	2.98	3.48	3.48
Total OPEC production	**32.60**	**31.89**	**29.32**	**36.62**	**30.10**	**43.52**	**34.54**
Non-OPEC							
OECD							
United States (50 states)	8.90	11.58	13.75	11.01	16.60	10.41	17.51
Canada	3.42	4.35	4.35	5.48	5.48	5.92	5.92
Mexico and Chile	2.59	2.61	2.61	3.00	3.00	3.45	3.45
OECD Europe[2]	2.82	2.17	2.17	1.66	1.66	1.69	1.69
Japan and South Korea	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Australia and New Zealand	0.37	0.47	0.47	0.67	0.67	0.75	0.75
Total OECD production	**18.10**	**21.18**	**23.35**	**21.83**	**27.42**	**22.23**	**29.33**
Non-OECD							
Russia	10.02	10.15	10.15	10.42	10.42	11.10	11.10
Other Europe and Eurasia[3]	3.05	3.18	3.18	4.03	4.03	4.66	4.66
China	4.16	4.54	4.54	4.56	4.56	4.13	4.13
Other Asia[4]	3.04	2.94	2.94	2.45	2.45	2.47	2.47
Middle East	1.16	1.00	1.00	0.82	0.82	0.74	0.74
Africa	1.97	2.18	2.18	2.38	2.38	2.70	2.70
Brazil	2.02	2.87	2.87	4.16	4.16	4.60	4.60
Other Central and South America	1.81	2.25	2.25	2.49	2.49	2.94	2.94
Total non-OECD production	**27.24**	**29.11**	**29.11**	**31.32**	**31.32**	**33.35**	**33.35**
Total crude oil production[6]	**77.9**	**82.2**	**81.8**	**89.8**	**88.8**	**99.1**	**97.2**
OPEC market share (percent)	41.8	38.8	35.8	40.8	33.9	43.9	35.5

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. **2013 quantities and projections:** Energy Information Administration (EIA), AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B; and EIA, Generate World Oil Balance application.

Appendix E

Comparison of AEO2015 and AEO2014 Reference cases and key updates to models and data

Introduction

This appendix provides a summary comparison of the Reference case for EIA's *Annual Energy Outlook 2015* (AEO2015) with the Reference case for the *Annual Energy Outlook 2014* (AEO2014),[1] which was released in April 2014, including a list of major model and data updates and discussion of key differences in results between the two projections. Table E1 compares projections from the AEO2014 and AEO2015 reports.

Model and data updates

Key model and data updates made for the AEO2015 Reference case include the following:

Macroeconomic

- Incorporated the U.S. Bureau of Economic Analysis (BEA) gross domestic product component revision to 2009 dollars and investment definitional changes.[2] The AEO2015 macroeconomic projections are based on November 2014 IHS Global Insight projections.[3]
- Incorporated a new input-output matrix based on a 2007 benchmark year using 2009 dollars. The input-output matrix now continues to change over time, based on historical relationships developed using previous benchmark matrices to 2013.

Residential, commercial, and industrial

- Incorporated new standards for buildings equipment promulgated during the year, including standards affecting commercial refrigeration equipment, metal halide lamp fixtures, residential furnace fans, external power supplies, and set-top boxes (voluntary agreement).
- Updated cost and performance assumptions for end-use equipment in the buildings sector, based on a report by Navigant Consulting, Inc. and Leidos, reflecting recent and expected technological progress.[4]
- Incorporated more rapid adoption of commercial building codes related to building shell efficiency, based on a Pacific Northwest National Laboratory report.[5]
- Revised and refined market niches used in developing residential distributed generation projections to more accurately reflect solar insolation and marginal prices at the sub-Census division level, based on data from EIA's 2009 Residential Energy Consumption Survey and solar insolation data from the National Renewable Energy Laboratory. [6,7]
- Incorporated 2012 State Energy Data System (SEDS) data for regional benchmarking in the industrial sector.[8]
- Updated and implemented historical natural gas feedstock data in the industrial sector through 2013, based on data from GlobalData.[9]
- Introduced a new Bayesian Dynamic Linear Model (DLM) for ethane and propane price projections in the industrial sector. In the DLM regression, parameters are allowed to vary over time to allow for a dynamic representation of various drivers of ethane and propane prices—such as oil price, natural gas price, hydrocarbon gas liquids (HGL) supply and demand, and bulk chemical shipments. The DLM projects base ethane and propane prices only at Mont Belvieu. To compute sectoral propane prices, historical differences between the base and sectoral prices for propane were applied to the DLM projections for propane. The resulting AEO2015 ethane and propane price projections exhibit a dominant natural gas price influence in the near term and a growing oil price influence in the long term.

[1]U.S. Energy Information Administration, Annual Energy Outlook 2014, DOE/EIA-0383(2014) (Washington, DC, April 2014), www.eia.gov/forecasts/archive/aeo14.

[2]S.H. McCulla, A.E. Holdren, and S. Smith, "Improved Estimates of the National Income and Product Accounts: Results of the 2013 Comprehensive Revision" (U.S. Department of Commerce, Bureau of Economic Analysis, Washington, DC, September 2013), http://www.bea.gov/scb/pdf/2013/09%20September/0913_comprehensive_nipa_revision.pdf.

[3]The AEO2015 Reference case uses IHS Global Insight's November 2014 T301114 workfile. The AEO2015 High Economic Growth case uses the optimistic projection, and the AEO2015 Low Economic Growth case uses the pessimistic projection. In all cases, IHSGI's energy prices and quantities are replaced with EIA's projections.

[4]U.S. Energy Information Administration, EIA—*Technology Forecast Updates—Residential and Commercial Building Technologies—Reference case* (Navigant Consulting, Inc. with Leidos, May 2014).

[5]O.V. Livingston, P.C. Cole, D.B. Elliott, and R. Bartlett, *Building Energy Codes Program: National Benefits Assessment, 1992-2040* (Richland, WA, March 2014), prepared by Pacific Northwest National Laboratory for the U.S. Department of Energy, Building Energy Codes Program, http://www.energycodes.gov/building-energy-codes-program-national-benefits-assessment-1992-2040-0.

[6]U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data" (Washington, DC, January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.

[7]National Renewable Energy Laboratory (NREL) "Zip Code Solar Insolation Data Source," http://www.nrel.gov/gis/docs/SolarSummaries.xlsx.

[8]U.S. Energy Information Administration, "State Energy Data System (SEDS)" (Washington, DC, June 27, 2014), http://www.eia.gov/state/seds/seds-data-complete.cfm?sid=US.

[9]GlobalData (New York, NY, 2014) http://www.globaldata.com (subscription site).

Table E1. Comparison of projections in the AEO2015 and AEO2014 Reference cases, 2012-40

			2025		2040	
Energy and economic factors	2012	2013	AEO2015	AEO2014	AEO2015	AEO2014
Primary energy production (quadrillion Btu)						
Crude oil and natural gas plant liquids	17.0	19.2	27.2	23.0	25.4	20.0
Dry natural gas	24.6	25.1	31.3	32.6	36.4	38.4
Coal[a]	20.7	20.0	22.2	22.4	22.6	22.6
Nuclear/uranium	8.1	8.3	8.5	8.2	8.7	8.5
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.9
Biomass	4.0	4.2	4.6	5.1	5.0	5.6
Other renewable energy	1.9	2.3	3.4	3.1	4.6	3.9
Other[b]	0.8	1.3	0.9	0.2	1.0	0.2
Total production	**79.6**	**82.7**	**100.9**	**97.4**	**106.6**	**102.1**
Net imports (quadrillion Btu)						
Liquid fuels and other petroleum[c]	16.4	14.0	7.4	11.4	8.6	13.7
Natural gas (- indicates exports)	1.6	1.4	-3.5	-3.4	-5.6	-5.8
Coal, coal coke, and electricity (- indicates exports)	-2.8	-2.6	-2.7	-3.2	-3.5	-3.7
Total net imports	**15.2**	**12.8**	**1.1**	**4.8**	**-0.5**	**4.2**
Energy consumption by fuel (quadrillion Btu)						
Liquid fuels and other petroleum[d]	35.2	35.9	36.9	36.3	36.2	35.4
Natural gas	26.1	26.9	27.6	29.0	30.5	32.3
Coal[a]	17.3	18.0	19.3	19.0	19.0	18.7
Nuclear/uranium	8.1	8.3	8.5	8.2	8.7	8.5
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.9
Biomass	2.8	2.9	3.2	3.7	3.5	4.3
Other renewable energy	1.9	2.3	3.4	3.1	4.6	3.9
Other[e]	0.4	0.4	0.3	0.3	0.3	0.3
Total consumption	**94.4**	**97.1**	**102.0**	**102.5**	**105.7**	**106.3**
Energy consumption by sector (quadrillion Btu)[f]						
Residential	19.9	21.1	20.3	20.6	20.9	21.5
Commercial	17.5	18.1	18.9	18.8	20.9	20.9
Industrial	30.8	31.2	36.5	37.4	37.7	38.3
Transportation	26.2	27.0	26.7	25.7	26.6	25.6
Unspecified sector[g]	0.0	-0.3	-0.4	--	-0.4	--
Total consumption	**94.4**	**97.1**	**102.0**	**102.5**	**105.7**	**106.3**
Liquid fuels (million barrels per day)						
Domestic crude oil production	6.5	7.4	10.3	9.0	9.4	7.5
Other domestic production	4.5	5.2	6.5	5.1	6.5	5.2
Net imports	7.4	6.2	2.8	5.1	3.4	6.0
Consumption	18.5	19.0	19.6	19.3	19.3	18.7
Natural gas (trillion cubic feet)						
Dry gas production and supplemental gas	24.1	24.5	30.6	31.9	35.5	37.6
Net imports (- indicates exports)	1.5	1.3	-3.5	-3.4	-5.6	-5.8
Consumption	25.5	26.2	26.9	28.4	29.7	31.6

-- = Not applicable.
See notes at end of table.

Table E1. Comparison of projections in the AEO2015 and AEO2014 Reference cases, 2012-40 (continued)

			2025		2040	
Energy and economic factors	2012	2013	AEO2015	AEO2014	AEO2015	AEO2014
Coal (million short tons)						
Production[a]	1,028	995	1,116	1,128	1,128	1,139
Net exports[h]	118	110	110	135	140	160
Consumption[a]	889	925	1,005	993	988	979
Electricity						
Total capacity, all sectors (gigawatts)	1,063	1,065	1,091	1,110	1,261	1,316
Total net generation, all sectors (billion kilowatthours)	4,055	4,070	4,513	4,622	5,056	5,219
Total electricity use (billion kilowatthours)	3,834	3,836	4,282	4,385	4,797	4,954
Prices (2013 dollars)						
Brent spot crude oil (dollars per barrel)	113	109	91	111	141	144
West Texas Intermediate spot crude oil (dollars per barrel)	96	98	85	109	136	142
Natural gas at Henry Hub (dollars per million Btu)	2.79	3.73	5.46	5.31	7.85	7.77
Domestic coal at minemouth (dollars per short ton)	40.5	37.2	40.3	50.4	49.2	60.0
Average electricity (cents per kilowatthour)	10.0	10.1	11.0	10.3	11.8	11.3
Economic indicators						
Real gross domestic product (trillion 2009 dollars)[i]	15.4	15.7	21.3	--	29.9	--
GDP chain-type price index (2009 = 1.00)[i]	1.05	1.07	1.31	--	1.73	--
Real disposable personal income (trillion 2009 dollars)[i]	11.7	11.7	16.3	--	23.0	--
Value of industrial shipments (trillion 2009 dollars)[i]	6.82	7.00	9.21	--	11.46	--
Population (millions)	315	317	347	347	380	381
Energy-related carbon dioxide emissions (million metric tons)	**5,272**	**5,405**	**5,511**	**5,526**	**5,549**	**5,599**
Primary energy intensity (thousand Btu per 2009 dollar of GDP)	**6.14**	**6.18**	**4.79**	**--**	**3.54**	**--**

[a]Includes waste coal consumed in the industrial and electric power sectors.
[b]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some inputs to refineries.
[c]Includes crude oil, petroleum products, petroleum coke, unfinished oils, alcohols, ethers, blending components, hydrocarbon gas liquids, and non-petroleum-derived fuels such as ethanol and biodiesel.
[d]Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel.
[e]Net electricity imports, liquid hydrogen, and non-biogenic municipal waste.
[f]Electric power sector consumption is distributed to the end-use sectors.
[g]Represents consumption unattributed to the sectors above.
[h]Excludes imports to Puerto Rico and the Virgin Islands.
[i]GDP, disposable income, value of shipments, and GDP price index were updated in AEO2015 consistent with the U.S. Bureau of Economic Analysis gross domestic product component revision to 2009 dollars and investment definitional changes. AEO2014 data are 2005-based and are not shown since they are not comparable with 2009-based figures.
Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors.
-- = Not applicable.

Transportation

- Updated the following by aircraft type and region: sales, stocks, and active and parked aircraft using Jet Inventory Services data;[10] available seat-miles traveled, revenue seat-miles traveled, cargo travel, fuel use, and load factors, using U.S. Department of Transportation, Bureau of Transportation Statistics data;[11] and domestic and international yield[12] using fares and fees published by Airlines for America.[13]
- Updated historical light-duty vehicle and heavy-duty truck vehicle-miles traveled through 2012, using data from U.S. Department of Transportation, Federal Highway Administration,[14] extended through 2014 using the U.S. Department of Transportation, Federal Highway Administration, *Traffic Volume Trends* report.[15]
- Added historical freight rail ton miles through 2013, using Class 1 Railroad data as reported through the U.S. Department of Transportation, Surface Transportation Board.[16]
- Added historical domestic marine ton miles through 2012, based on U.S. Army Corps of Engineers data.[17]
- Revised heavy-duty vehicle, freight rail, and domestic marine travel demand projection methodologies based on a report from IHS Global Insight.[18] The new methodologies will use the Freight Analysis Framework[19] in the historical Census division and commodity ton-mile data, including derivation of ton mile per dollar of industrial output (a key metric used in the travel demand projection methodology). These data include a Geographic Information System modeling estimation of the share of freight truck travel between origin and destination points through intermediate Census divisions.
- Modified the technology adoption and fuel economy calculation for heavy-duty vehicles and added technology availability.
- Modified the domestic and international marine residual fuel oil and distillate fuel shares to match compliance with MARPOL Annex VI,[20] the International Convention for the Prevention of Pollution from Ships, concerned with preventing marine pollution from ships, as assumed in EIA's *Short-Term Energy Outlook*.
- Added an unspecified consumption sector to match the levels of travel and efficiency more consistently with implied fuel use in the transportation sector, and to allow total liquid fuels[21] consumption in AEO2015 to be closer to the totals for each fuel that are reported in EIA's statistical publications as being supplied to markets.

Oil and natural gas production

- Incorporated the impact of world oil prices that remain below $80/bbl (in 2013 dollars) through 2020, versus $98/bbl in AEO2014, to reflect market events through the end of 2014 and the growth of U.S. crude oil production. This change in price expectations limits the degree to which near-term U.S. crude oil and associated dry natural gas production increase, and limits the need for natural gas produced for liquefied natural gas (LNG) exports.
- Revised drilling costs in AEO2015 to directly incorporate assumptions regarding average lateral length and number of laterals per well.
- Updated natural gas plant liquid (NGPL) factors at the play and county levels for tight oil and shale gas formations.
- Updated the estimated ultimate recovery of tight and shale formations at the county level. For the Marcellus Shale, each county was further divided into productive tiers based on geologic dependencies.
- Updated the list of offshore discovered, non-producing fields and the expected resource sizes and startup dates of the fields.

[10]Jet Information Services, Inc., "World Jet Inventory" (Utica, NY, December 2013), http://www.jetinventory.com (subscription site).
[11]U.S. Department of Transportation, Bureau of Transportation Statistics, Form 41, Schedule T-2 (T-100), "Quarterly Traffic and Capacity Data of U.S. Air Carriers, Summarized by Aircraft Type" (Washington, DC, December 2013).
[12]Yield is defined as airline revenue divided by revenue passenger miles traveled.
[13]Airlines for America, "Annual Round Trip Fares and Fees" (Washington, DC, August 2014), http://airlines.org/data/annual-round-trip-fares-and-fees-domestic/ and http://airlines.org/data/annual-round-trip-fares-and-fees-international/.
[14]U.S. Department of Transportation, Federal Highway Administration, "Highway Statistics 2012: Table VM-1, Annual Vehicle Distance Traveled in Miles and Related Data—2012 by Highway Category and Vehicle Type" (Washington, DC, January 2014), http://www.fhwa.dot.gov/policyinformation/statistics/2012/vm1.cfm.
[15]U.S. Department of Transportation, Federal Highway Administration, "June 2014 Traffic Volume Trends" (Washington, DC, June 2014), https://www.fhwa.dot.gov/policyinformation/travel_monitoring/14juntvt/.
[16]U.S. Department of Transportation, Surface Transportation Board, "Annual Report Financial Data" (Washington, DC, 2013), http://www.stb.dot.gov/stb/industry/econ_reports.html.
[17]U.S. Department of Defense, U.S. Army Corps of Engineers, "Waterborne Commerce of the United States, Calendar Year 2012, Part 5—National Summaries, Table 1.4: Total Waterborne Commerce, 1993-2012" (Washington, DC, 2014), http://www.navigationdatacenter.us/wcsc/pdf/wcusnatl12.pdf.
[18]IHS Global, Inc., "NEMS Freight Transportation Module Improvement Study" (June 20, 2014).
[19]U.S. Department of Transportation, Federal Highway Administration, "Freight Analysis Framework," http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/.
[20]U.S. Environmental Protection Agency, "MARPOL Annex VI" (Washington, DC: January 14, 2015), http://www2.epa.gov/enforcement/marpol-annex-vi.
[21]Liquid fuels (or petroleum and other liquids) include crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

- Moved the projection of the composition of NGPL from the Liquid Fuels Market Module (LFMM) to the Oil and Gas Supply Module (OGSM). Added input data in the OGSM for the component (ethane, propane, butane, and pentanes plus) shares of total NGPL at the project level represented in the OGSM. Added capability to account for the volume of ethane that is left in the dry natural gas stream (commonly referred to as *ethane rejection*).

Natural gas transmission and distribution

- Expanded natural gas distribution in AEO2015 to represent a greater number of pipeline routes that allow for bidirectional flows.
- Allowed LNG projects to be added incrementally by a single train rather than by multiple trains and to phase-in over three years rather than two years.
- In circumstances when the Brent price is above (below) a mid-range value, the model can now set world natural gas prices to disconnect from the Brent price at a faster (slower) rate than it would have previously.
- Updated the pricing algorithm for offshore Atlantic and Pacific production.
- Adjusted the representation of Canadian dry natural gas production.
- Increased base-level production to account for a change in Mexico's constitution allowing for increased foreign investment.

Petroleum product and biofuels markets

- Added 40°-50° American Petroleum Institute (API) and 50°+ API crude oil types to reflect increases in tight oil production and potential constraints on refinery processing.
- Included the option to add new condensate splitter units to process 50°+ API crude.
- Modified the LFMM and International Energy Module to permit crude exports to accommodate analysis of the impact of potential relaxation of the current U.S. crude oil export ban.
- Relaxed export restrictions on processed condensate to better match the U.S. Department of Commerce, Bureau of Industry and Security, interpretation of export regulations that allow the export of processed condensate.
- Updated gasoline specifications to reflect Tier 3 gasoline regulations.
- Revised the renewable fuels standard mandate levels for biomass-based diesel to better match expected production capabilities.[22]

Electric power sector

- Revised the assumption for unannounced nuclear retirements in the Reference case downward, from 5.7 gigawatts (GW) in the AEO2014 Reference case to 2 GW in the AEO2015 Reference case. Unannounced nuclear retirements in the AEO2015 Reference case reflect market uncertainty. Announced nuclear retirements are incorporated as reported to the EIA.
- Updated the online start dates for Virgil C. Summer Nuclear Generating Station Units 2 and 3 to 2019 and 2020, respectively, to reflect company announcements.[23]
- Updated expiration dates of firm contractual arrangements for coal-fired power plants that serve California loads.[24] Adjusted the carbon emissions rate for firm imports in accordance with the expiration of contracts.
- Explicitly represented 4.1 GW of coal-fired units that are being converted to natural gas-fired steam units. Added model capability to convert additional coal-fired plants to natural gas-fired plants based on the relative economics, assuming a capital cost for conversion and connection to natural gas pipelines. Once converted, the oil and natural gas steam plants are assumed to have lower operating and maintenance costs than the original coal-fired plant but also a 5% loss in efficiency.
- Updated regional assumptions on transmission and distribution spending as a function of peak load growth, based on historical trends.
- Revised biomass supply model representation of agricultural residues/energy crop feedstocks, by incorporating fully-integrated agricultural model, Policy Analysis System (POLYSYS).

[22]U.S. Energy Information Administration, Monthly Biodiesel Production Report (Washington, DC: July 31, 2014), http://www.eia.gov/biofuels/biodiesel/production/.

[23]SCANA Corporation, "SCANA Corporation Management to Discuss New Nuclear Construction Schedule on August 11, 2014" (Cayce, SC: August 2014), https://www.scana.com/docs/librariesprovider15/pdfs/press-releases/8-11-2014-scana-dicuss-new-nuclear-schedule.pdf?sfvrsn=0.

[24]California Energy Commission, "Actual and Expected Energy from Coal for California" (Sacramento, CA: November 6, 2014), http://www.energy.ca.gov/renewables/tracking_progress/documents/current_expected_energy_from_coal.pdf. Changes in coal contract deliveries are largely related to the California Public Utilities Commission's adopted Greenhouse Gas Emissions Performance Standard (Decision 07-01-039, January 25, 2007, Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard, http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/64072.htm), which implemented Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006, http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf).

- Reviewed and updated capital cost assumptions for utility-scale solar PV and wind plants based on assessment of costs reported in trade press and data compiled in Lawrence Berkeley National Laboratory publications *2013 Wind Technologies Market Report*[25] and *Utility-Scale Solar 2013*.[26]
- Added model capability to retrofit existing coal-fired generating units to improve their operating efficiency (heat rate), if economic. An analysis of the heat rate improvement potential of the existing coal fleet sorted existing coal-fired units into quartiles, to reflect varying levels of improvement potential, and developed cost estimates to reflect the investment required to achieve the improvement. The analysis then disaggregated the cost and improvement assumptions based on environmental control configurations, consistent with the coal plant types used in the electricity model. Heat rate improvement retrofits can provide a reduction in fuel use ranging from less than 1% to 10%, depending on the plant type and quartile.

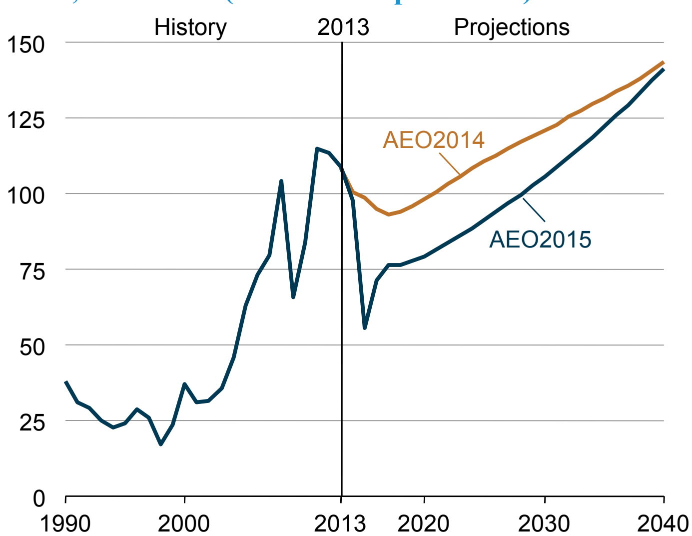
Comparison of AEO2015 and AEO2014 Reference cases

Economic growth

The macroeconomic projections used in AEO2015 are trend projections, with no major shocks anticipated. In long-term projections, the economy's supply capability determines its potential growth. Growth in aggregate supply depends on increases in the labor force, growth of capital stock, and improvements in productivity. Long-term demand growth depends on labor force growth, income growth, and population growth. In the AEO2015 Reference case, U.S. population grows by an average of 0.7%/year from 2013 to 2040, the same rate as in the AEO2014 Reference case over the same period. In the AEO2015 Reference case, real gross domestic product (GDP), labor force, and productivity grow by 2.4%/year, 0.6%/year, and 2.0%/year, respectively, over the same period. Those rates are similar to the annual growth rates for real GDP, labor force, and productivity of 2.5%, 0.6%, and 1.9%, respectively, from 2013 to 2040 in the AEO2014 Reference case.

The annual rate of growth in total industrial production, which includes manufacturing, construction, agriculture, and mining, in the AEO2015 Reference case is lower than the rate in the AEO2014 Reference case, primarily as a result of slower growth in key manufacturing industries, such as food, paper, non-bulk chemicals, and computers. Updated information on how industries supply other industries and meet the demand for different types of GDP expenditures influences the projections for certain industries.[27]For example, as a result of restructuring in the pulp and paper industry, trade in consumer goods and industrial supplies has a greater impact on the industry's production in AEO2015 than it did in previous AEOs. The annual rate of growth in total industrial production from 2013 to 2040 is 1.8% in AEO2015, compared with 2.1% in AEO2014. The manufacturing share of total gross output in 2040 is 17% in the AEO2015 Reference case, compared with 18% in AEO2014, mostly because of more-rapid growth in service and nonmanufacturing industries, such as wholesale trade, transportation, and warehousing.

Figure E1. Average annual Brent crude oil spot prices in the AEO2015 and AEO2014 Reference cases, 1990-2040 (2013 dollars per barrel)



Energy prices

Crude oil

In the AEO2015 Reference case, the Brent spot price for crude oil (in 2013 dollars) falls from $109/barrel (bbl) in 2013 to $56/bbl in 2015 and then increases to $76/bbl in 2018. After 2018, the Brent price increases, reaching $141/bbl in 2040 ($229/bbl in nominal dollars), as growing demand leads to the development of more costly resources (Figure E1). In the AEO2014 Reference case, the projected Brent price in 2040 was $144/bbl (2013 dollars).

Among the key assumptions that affect crude oil use in the AEO2015 Reference case are average economic growth of 1.9%/year for major U.S. trading partners;[28] average economic growth for other U.S. trading partners of 3.8%/year; and declining U.S. consumption of liquid fuels per unit of GDP. As a result, there is a slight decrease in liquids consumption by the Organization for Economic Cooperation and Development (OECD) countries.

[25]R. Wiser and M. Bolinger, 2013 Wind Technologies Market Report, DOE/GO-102014-4459 (Washington, DC: August 2014), http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.

[26]M. Bolinger and S. Weaver, Utility-Scale Solar 2013 (Washington, DC: September 2014), http://emp.lbl.gov/sites/all/files/LBNL_Utility-Scale_Solar_2013_report.pdf.

[27]The industrial output model of the NEMS Macroeconomic Activity Module now uses the Bureau of Economic Analysis (BEA) detailed input-output matrices for 2007 rather than for 2002 (http://bea.gov/industry/io_annual.htm) and now incorporates information from the aggregate input-output matrices (http://bea.gov/industry/gdpbyind_data.htm).

[28]Major trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.

The non-OECD consumption level of 75 million barrels per day (bbl/d) in 2040 in the AEO2015 Reference case is about 7% higher than the 2040 level in the AEO2014 Reference case, and the difference more than offsets the impact of lower consumption in the OECD countries. The result is an increase in total world consumption to 121 million bbl/d in 2040 in AEO2015, which is 3% higher than in AEO2014. Non-OPEC (particularly U.S.) liquids production in AEO2015 increases to levels above those in AEO2014, and the OPEC market share in the AEO2015 Reference case rises only slightly, from 40% in 2013 to 41% in 2040, as compared with a 44% market share in 2040 in AEO2014.

Liquid products

The real U.S. price of end-use motor gasoline (2013 dollars) in the AEO2015 Reference case falls from $3.53/gallon in 2013 to a low point of $2.31/gallon in 2015, before rising to $3.90/gallon in 2040, in response to decreasing—and then increasing—crude oil prices. The motor gasoline price in 2040 is 2% lower than the $3.96/gallon price in the AEO2014 Reference case, because of lower crude oil prices. The end-use price of diesel fuel to the transportation sector in the AEO2015 Reference case follows a similar pattern, dropping from $3.86/gallon in 2013 to $2.70/gallon in 2015 and then rising to $4.75/gallon in 2040 (compared with $4.80/gallon in 2040 in the AEO2014 Reference case).

Natural gas

On average, the Henry Hub spot price for natural gas in the AEO2015 Reference case is only 2% (or $0.13/million Btu in 2013 dollars) lower than in the AEO2014 Reference case from 2013 to 2040. The Henry Hub natural gas spot prices in AEO2015 are slightly lower than the AEO2014 spot prices in each year, with the exception of the period from 2020 to 2027 and in 2040. These price levels are consistent with 3% lower cumulative U.S. dry natural gas production through 2040 in the AEO2015 Reference case relative to the AEO2014 Reference case.

Although the average production, consumption, and price levels are similar in the AEO2015 and AEO2014 Reference cases, there are some notable differences in the components. For instance, while natural gas consumption by natural gas vehicles and electricity generators in AEO2015 is lower than in AEO2014, residential and commercial consumption are generally higher. On the supply side, higher dry natural gas production in the AEO2015 Reference case in the East region (which includes the Marcellus and Utica formations) compared with the AEO2014 Reference case is more than offset by lower production levels in the Gulf Coast and Midcontinent regions. The relative location and composition of supply and demand affect regional pricing and national averages. For this and other reasons, average delivered natural gas prices to residential and commercial customers from 2013 to 2040 are 4% lower in the AEO2015 Reference case than in the AEO2014 Reference case.

Coal

The average minemouth price of coal increases by 1.0%/year, from $1.84/million Btu in 2013 to $2.44/million Btu in 2040 (2013 dollars) in the AEO2015 Reference case. In comparison, the price in the AEO2014 Reference case increases by 1.5%/year, from $2.02/million Btu in 2013 to $3.00/million Btu in 2040. The average minemouth price of coal is about 19% lower, on average, across the projection timeframe in AEO2015 when compared with AEO2014, reflecting lower volumes and prices for high-priced coking coal exports, the shutdown of some high-cost mining operations, and a less pessimistic outlook for productivity. Similarly, with a few exceptions, the regional minemouth prices of coal in AEO2015 are lower than those in AEO2014.

The slower rate of increase in the minemouth price of coal in the AEO2015 Reference case reflects recent year-over-year improvements in labor productivity in 9 of the 14 coal supply regions, many of which have not seen productivity gains since 2000, and a slowing of productivity declines in 4 of the other regions. However, both the AEO2015 and AEO2014 Reference cases assume that cost savings from improvements in coal mining technology will continue to be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. Thus, both projections show the average minemouth price of coal rising steadily after 2015.

Electricity

In the AEO2015 Reference case, end-use electricity prices are higher than in the AEO2014 Reference case throughout most of the projection. The higher price outlook reflects market dynamics, as well as revised assumptions for transmission and distribution costs in AEO2015.

The end-use price of electricity is defined by generation, transmission, and distribution cost components. Natural gas prices are a significant determinant of generation costs. In the AEO2015 Reference case, delivered natural gas prices to electricity generators are lower than in the AEO2014 Reference case in the first few years of the projection but higher throughout most of the 2020s. From 2020 to 2030, the generation cost component of end-use electricity prices is, on average, 4% higher in AEO2015 than in AEO2014.

The AEO2015 Reference case includes higher transmission and distribution cost components relative to the AEO2014 Reference case, reflecting an updated representation of trends in transmission and distribution costs. In 2040, the transmission cost component in the AEO2015 Reference case is 14% higher than it was in the AEO2014 Reference case—1.29 cents/kilowatthour (kWh), compared with 1.13 cents/kWh—while the distribution cost component is 15% higher (3.01 cents/kWh compared with 2.61 cents/kWh). The faster growth in the transmission and distribution cost components of end-use electricity prices in

AEO2015 reflects recent historical trends and an expectation that transmission and distribution costs will continue to increase as new transmission and distribution facilities and *smart grid* components (e.g., advanced meters, sensors, controls, etc.) are added, existing infrastructure is upgraded to enhance the reliability and resiliency of the grid, and new resources connect to the grid.

Average end-use electricity price in 2030 is 11.1 cents/kWh (2013 dollars) in the AEO2015 Reference case, compared to 10.6 cents/kWh in the AEO2014 Reference case. Prices continue rising to 11.8 cents/kWh in 2040 in the AEO2015 Reference case, compared to 11.3 cents/kWh in 2040 in the AEO2014 Reference case.

Energy consumption by sector

Transportation

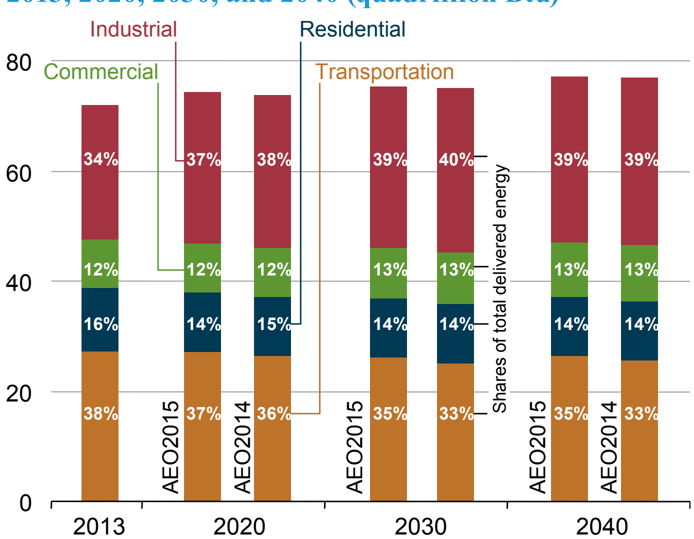
Delivered energy consumption in the transportation sector in the AEO2015 Reference case is higher than in AEO2014 (26.5 quadrillion Btu in 2040 compared with 25.5 quadrillion Btu), with energy consumption for nearly all transportation modes higher in AEO2015 throughout most of the projection, because of higher macroeconomic indicators and lower fuel prices (Figure E2).

Light-duty vehicle (LDV) energy consumption declines in the AEO2015 Reference case from 15.7 quadrillion Btu in 2013 to 12.6 quadrillion Btu in 2040, compared with 12.1 quadrillion Btu in 2040 in AEO2014. Greenhouse gas emission standards and corporate average fuel economy (CAFE) standards increase new LDV fuel economy through model year 2025 and beyond in the AEO2015 Reference case, with new, more fuel-efficient vehicles gradually replacing older vehicles on the road. The increase in fuel economy raises the LDV vehicle stock average miles per gallon by 2.0%/year, from 21.9 in 2013 to 37.0 in 2040. The increase in LDV fuel economy more than offsets modest growth in vehicle-miles traveled (VMT), which averages 1.1%/year from 2013 to 2040 as a result of changes in driving behavior related to demographics. Stock fuel economy is lower, and LDV VMT is higher, in the AEO2015 Reference case than in AEO2014.

LDVs powered exclusively by motor gasoline remain the predominant vehicle type in the AEO2015 Reference case, retaining a 78% share of new vehicle sales in 2040, down only somewhat from 83% in 2013. The fuel economy of LDVs fueled by motor gasoline continues to increase, and advanced technologies for fuel efficiency subsystems are added, such as micro hybridization, which is installed in 42% of new motor gasoline LDVs in 2040. Sales of new LDVs powered by fuels other than gasoline (such as diesel, electricity, or E85) and LDVs using hybrid drivetrains (such as plug-in hybrid or gasoline hybrid-electric vehicles) increase modestly in the AEO2015 Reference case, from 17% of new sales in 2013 to 22% in 2040. Ethanol-flex-fuel vehicles account for 10% of new LDV sales in 2040 followed by hybrid electric vehicles at 5%, up from 3% in 2013, diesel vehicles at 4% in 2040, up from 2% in 2013, and plug-in hybrid vehicles and electric vehicles at about 1% each, both up from negligible shares in 2013. In AEO2015, new vehicle sales shares in 2015 are generally similar to those in AEO2014. In AEO2014, the motor gasoline share of new LDVs sales was 78% in 2040 (with 42% including micro hybridization), followed by 11% ethanol-flex-fuel, 5% hybrid electric, 4% diesel, and 1% each for plug-in hybrid and electric vehicles.

In the AEO2015 Reference case, delivered energy use by heavy-duty vehicles (HDVs) increases from 5.8 quadrillion Btu in 2013 to 7.3 quadrillion Btu in 2040 (compared with 7.5 quadrillion Btu in 2040 in AEO2014). Industrial output growth in AEO2015 leads to solid growth in HDV VMT, averaging 1.5%/year from 2013 to 2040. Competitive natural gas prices significantly increase demand for LNG and compressed natural gas in AEO2015, from an insignificant share in 2013 to 7% of total HDV energy consumption in 2040 (which is less than the 9% share in AEO2014, as a result of differences in fuel price projections).

Figure E2. Delivered energy consumption by end-use sector in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040 (quadrillion Btu)



Industrial

Total industrial delivered energy consumption grows by 22% in the AEO2015 Reference case, to about 30 quadrillion Btu in 2040, which is about 0.4 quadrillion Btu lower than the 2040 projection in the AEO2014 Reference case. The lower level of total industrial energy consumption in AEO2015 results from lower annual growth in the total value of industrial shipments (1.8%/year) compared with AEO2014 (2.1%/year).

Although total energy consumption levels are similar in the AEO2015 and AEO2014 Reference cases, there are some notable changes in consumption of individual fuels. In AEO2015, the liquid feedstock slate for the bulk chemical industry includes relatively more HGL (ethane and liquefied petroleum gases (LPG)) and less heavy feedstock (naphtha and gasoil) compared with AEO2014. The higher level of HGL feedstock use results from relatively low ethane and LPG prices relative to the prices of oil-based naphtha/gasoil feedstock, as a result of more HGL supply in the AEO2015

Reference case than in AEO2014 and the implementation of a new ethane pricing model that links ethane prices more closely with natural gas prices.

Another notable change from AEO2014 in the AEO2015 Reference case is that total consumption of renewable fuels is more than 0.5 quadrillion Btu lower in AEO2015 as a result of lower shipments from the paper and pulp industry. Industrial electricity consumption is also lower in AEO2015, in part as a result of lower shipments of metal-based durables, especially computers. Through 2022, natural gas consumption is higher in the AEO2015 Reference case than in AEO2014, as a result of higher lease and plant fuel use and an increase in feedstock use, reflecting more optimistic assumptions for ammonia and methanol plant operations based on recent trends. However, after 2022 natural gas consumption is lower in the AEO2015 Reference case, because of lower lease and plant fuel use stemming from lower dry natural gas production, and because of lower shipments in the natural gas-intensive paper and pulp industry.

Residential

Residential delivered energy consumption decreases slightly in the AEO2015 Reference case from 2013 to 2040, with growth in electricity consumption offset by declining use of fossil fuels. Consumption levels are lower than those in the AEO2014 Reference case for most fuels, although natural gas use is slightly higher because of lower projected prices. Delivered electricity consumption is 5.4 quadrillion Btu and natural gas consumption is 4.3 quadrillion Btu in 2040 in AEO2015, compared with 5.7 quadrillion Btu and 4.2 quadrillion Btu, respectively, in AEO2014. The lower consumption levels in AEO2015 are explained in part by slower near-term growth in the number of households.

Commercial

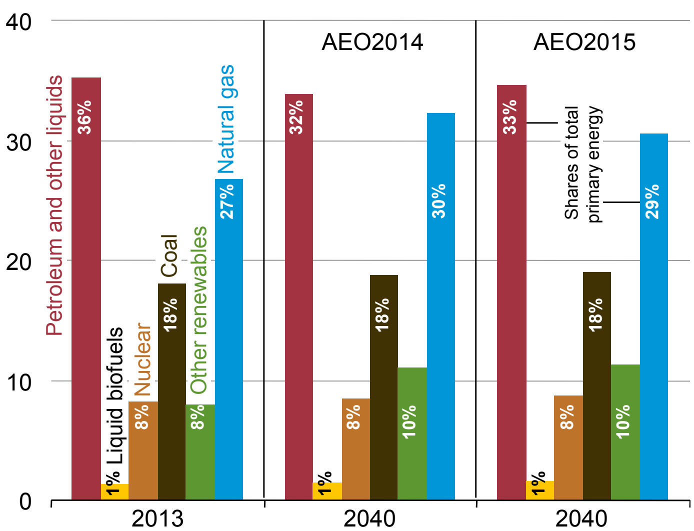
Commercial sector delivered energy consumption grows from 8.7 quadrillion Btu in 2013 to 10.1 quadrillion Btu in 2040 in the AEO2015 Reference case, similar to the AEO2014 Reference case, despite higher consumption in the near term. Commercial electricity consumption increases by 0.8%/year from 2013 to 2040 in AEO2015, lower than the 1.0% average annual growth in commercial floorspace, in part, because of lower demand for lighting and refrigeration than projected in AEO2014.

Energy consumption by primary fuel

Total primary energy consumption grows by 8.8% in the AEO2015 Reference case, from 97.1 quadrillion Btu in 2013 to 105.7 quadrillion Btu in 2040—600 trillion Btu less than in AEO2014, where total primary energy consumption grew by 10.2% to 106.3 quadrillion Btu in 2040 (Figure E3).

Total liquid fuels consumption increases slightly (300 trillion Btu) in the AEO2015 Reference case (the AEO2014 Reference case showed a decline of 600 trillion Btu), as declining consumption of motor gasoline offsets most of the growth in other liquids uses from 2013 to 2040. However, total liquid fuel consumption is 0.9 quadrillion Btu higher in 2040 in the AEO2015 Reference case than in the AEO2014 Reference case. Jet fuel, motor gasoline, and industrial propane use are each about 500 trillion Btu higher in 2040 in AEO2015 than in AEO2014, as a result of updates and revisions made in the air transportation model and lower petroleum fuel prices, as well as upward revisions in output projections for the chemical industry. Liquids consumption in the transportation sector also increases in AEO2015 as the result of the addition of an *unspecified* consumption sector, which was added to improve the consistency of matching travel and efficiency levels with implied fuel use in the transportation sector, so that total consumption of liquid fuels in AEO2015 agrees more closely with the combined total for all fuels reported as being supplied to markets in EIA statistical publications.

Figure E3. Primary energy consumption by fuel in the AEO2015 and AEO2014 Reference cases, 2013 and 2040 (quadrillion Btu)



In the AEO2015 Reference case, domestic natural gas consumption increases from 26.2 trillion cubic feet (Tcf) in 2013 to 29.7 Tcf in 2040, 1.9 Tcf lower than in the AEO2014 Reference case. The lower level of total natural gas consumption results from a 1.9 Tcf lower level of natural gas use in the electric power sector in 2040 in AEO2015. Natural gas consumption in the residential and commercial sectors is up slightly.

In the electric power sector, natural gas faces increased competition from nuclear power and renewables, particularly wind. Also, demand for electricity in the buildings sector in 2040 is about 0.3 quadrillion Btu lower than in AEO2014, as a result of increases in building efficiency standards and updates to lighting parameters in AEO2015. Electricity demand is also lower in some industrial sectors where output does not increase as rapidly in AEO2015 as was projected in AEO2014.

Total coal consumption in the AEO2015 Reference case is 19.0 quadrillion Btu (988 million short tons) in 2040—similar to the AEO2014 Reference case projection of 18.7 quadrillion Btu (979 million short tons) in 2040.

Total consumption of marketed renewable fuels grows by 1.3%/year in the AEO2015 Reference case, the same rate of growth as in the AEO2014 Reference case. However, the mix of renewable fuels is different in AEO2015, with more use of wind in the electric power sector, and less use of biomass in the industrial sector as a result of lower overall shipments in the paper industry. AEO2015 includes 3.0 quadrillion Btu of wind energy consumption in the electric power sector in 2040, compared with 2.4 quadrillion Btu in AEO2014, and the paper industry uses 1.2 quadrillion Btu of wood and pulping liquor in 2040 compared with 1.9 quadrillion Btu in 2040 in the AEO2014 Reference case.

Energy production and imports

In the AEO2015 Reference case, U.S. imports and exports of energy come into balance around 2028 as net energy imports decline both in absolute terms and as a share of total U.S. energy consumption (Figure E4). The United States is a net energy exporter in selected years—for example, from 2029 through 2032, and from 2037 through 2040. Over the projection period, the United States shifts from being a net importer of about 12.8 quadrillion Btu of energy in 2013 (about 13% of total U.S. energy demand) to a net exporter of about 0.5 quadrillion Btu in 2040. In the AEO2014 Reference case, the United States remained a net importer of energy, with net imports of about 4.2 quadrillion Btu in 2040.

Liquids

U.S. crude oil production in the AEO2015 Reference case increases from 7.4 million bbl/d in 2013 to 9.4 million bbl/d in 2040—26% higher than in the AEO2014 Reference case, despite lower prices. Production in AEO2015 reaches 10.6 million bbl/d in 2020, compared with a high of 9.6 million bbl/d in 2019 in AEO2014. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very low permeability) formations. Lower 48 onshore tight oil production reaches 5.6 million bbl/d in 2020 in the AEO2015 Reference case before declining to 4.3 million bbl/d in 2040, 34% higher than in AEO2014. The pace of oil-directed drilling in the near term is faster in AEO2015 than in AEO2014, as producers continue to locate and target the *sweet spots* of plays currently under development.

Lower 48 offshore crude oil supply grows from 1.4 million bbl/d in 2013 to 2.2 million bbl/d in 2019 in the AEO2015 Reference case, before fluctuating in accordance with the development of projects in the deepwater and ultra-deepwater portions of the Gulf of Mexico. In 2040, Lower 48 offshore production totals 2.2 million bbl/d in AEO2015, 9% more than in the AEO2014 Reference case.

U.S. net imports of liquid fuels as a share of total domestic consumption continue to decline in the AEO2015 Reference case, primarily as a result of increased domestic oil production. Net imports of liquid fuels as a share of total U.S. liquid fuel use reached 60% in 2005 before dipping below 50% in 2010 and falling to an estimated 33% in 2013 (Figure E5). The net import share of domestic liquid fuels consumption declines to 14% in 2020 in the AEO2015 Reference case—compared with 26% in the AEO2014 Reference case—as a result of faster growth of domestic liquid fuels supply[29] compared with growth in consumption. Domestic liquid fuels supply begins to decline after 2023 in the AEO2015 Reference case, and as a result, the net import share of domestic liquid fuels consumption rises from 14% in 2022 to 17% in 2040. However, domestic liquid fuels supply in the AEO2015 Reference case is 25% higher in 2040 than in the AEO2014 Reference case, while domestic consumption is only 3% higher. As a result, despite increasing after 2020, the percentage of U.S. liquid fuel supply from net imports in the AEO2015 Reference case remains just over half that in the AEO2014 Reference case through 2040.

Figure E4. Total energy production and consumption in the AEO2015 and AEO2014 Reference cases, 1980-2040 (quadrillion Btu)

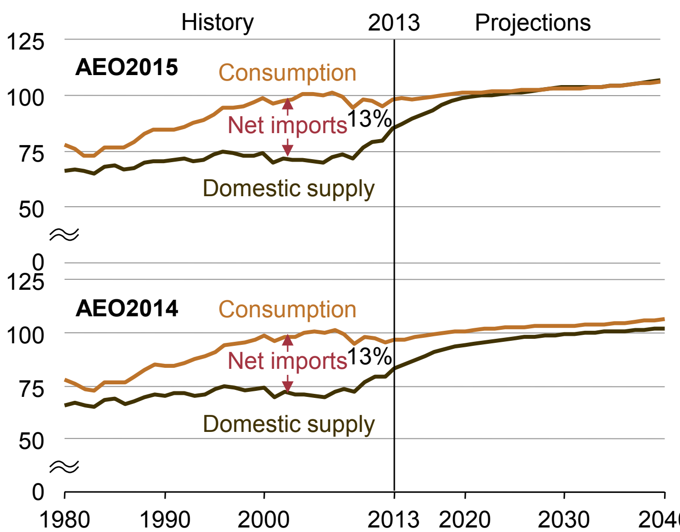
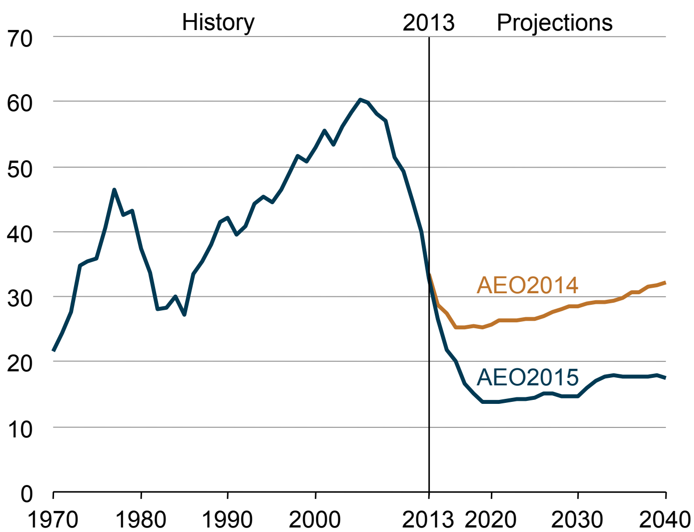


Figure E5. Share of U.S. liquid fuels supply from net imports in the AEO2015 and AEO2014 Reference cases, 1970-2040 (percent)



[29] Total domestic liquid fuels minus net imports, plus domestic HGL production.

Natural gas

In the AEO2015 Reference case, U.S. production of dry natural gas after 2019 is lower than in the AEO2014 Reference case projection, and in 2040 it is lower by more than 2 trillion cubic feet (Tcf). Lower production levels are a result of lower natural gas prices and a decrease in demand for natural gas by electricity generators because of fewer nuclear plant retirements and more renewable generation capacity in AEO2015. However, dry natural gas production from shale gas and tight oil plays is generally higher in AEO2015, offsetting some of the decreases in other areas. Increases in shale gas production are made possible by the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale plays and other resources with high concentrations of natural gas liquids and crude oil, which, in energy-equivalent terms, have a higher value than dry natural gas, even with lower crude oil prices.

In the AEO2015 Reference case, the United States becomes an overall net exporter of natural gas in 2017, one year earlier than in AEO2014, and a net pipeline exporter of natural gas in 2018, three years earlier than in AEO2014. In the AEO2015 Reference case, imports from Canada, which largely enter the western United States, and exports into Canada, which generally exit out of the East, are generally lower than in the AEO2014 Reference case. Imports from Canada remain lower in the AEO2015 Reference case than in the AEO2014 Reference case through 2040, while exports to Canada are higher in the AEO2015 Reference case from 2021 to 2028, before decreasing below AEO2014 levels through 2040. Net pipeline imports from Canada fall steadily until 2030 in AEO2015, then increase modestly through 2040, when growth in shale production stabilizes in the United States but continues to increase in Canada.

Net pipeline exports to Mexico increase almost twofold in the AEO2015 Reference case from 2017 to 2040, with additional pipeline infrastructure added to enable the Mexican market to receive more natural gas via pipeline from the United States. However, pipeline exports to Mexico in the later years of the AEO2015 Reference case are lower than projected in the AEO2014 Reference case, because Mexico is assumed to increase domestic production as a result of constitutional reforms that permit more foreign investment in its oil and natural gas industry.

Beginning in 2024, exports of liquefied natural gas (LNG) are slightly lower in the AEO2015 Reference case than in AEO2014, driven by lower crude oil prices. However, the impact of crude oil prices on the projection is dampened by changes in assumptions about how rapidly new LNG export terminals will be built.

Coal

Total U.S. coal production in the AEO2015 Reference case grows at an average rate of 0.5%/year, from 985 million short tons (19.9 quadrillion Btu) in 2013 to 1,117 million short tons (22.5 quadrillion Btu) in 2040. In comparison, U.S. production in the AEO2014 Reference case was projected to increase by 0.3%/year, from 1,022 million short tons (20.7 quadrillion Btu) in 2013 to 1,121 million short tons (22.4 quadrillion Btu) in 2040. Actual coal production in 2013 was 4% lower than projected in AEO2014, as a result of a large drawdown of coal inventories at coal-fired power plants.

From 2013 through 2020, coal production in the AEO2015 Reference case is lower than projected in the AEO2014 Reference case, as lower natural gas prices result in the substitution of natural gas for coal in power generation. After 2020, total coal production in the AEO2014 and AEO2015 projections are nearly identical, with both hovering around 1.1 billion short tons through 2040, because of similar patterns of capacity additions and retirements at coal-fired power plants and similar coal-fired capacity utilization rates in the two projections. The outlook for U.S. coal exports is lower in AEO2015 than in AEO2014 throughout the projection period. Between 2013 and 2015, U.S. coal exports decline sharply in the AEO2015 Reference case as a result of strong international competition and lower international coal prices; but from 2015 through 2040 they increase gradually. Compared with AEO2014, coal exports in AEO2015 are 27% lower in 2015 and 13% lower in 2040.

Overall, regional patterns of U.S. coal production are similar in the AEO2015 and AEO2014 Reference cases. Production in the Eastern Interior region increases in both projections by about 100 million short tons from 2013 to 2040. The AEO2015 outlook for Central Appalachian coal production is similar to the AEO2014, but is about 7 million short tons (7%) higher, on average, than the AEO2014 from 2015 through 2040. Northern Appalachian coal production in 2040 is 20 million short tons lower in AEO2015 than projected in the AEO2014 Reference case. Production from Wyoming's Powder River Basin, currently the lead coal-producing region in the United States, is lower from 2013 through 2018 in AEO2015 than projected in AEO2014, but then increases at a more rapid pace through 2026 before declining slightly and eventually moving to levels consistent with the AEO2014 projection from 2032 through 2040.

Electricity generation

Total electricity consumption in the AEO2015 Reference case, including both purchases from electric power producers and on-site generation, grows from 3,836 billion kWh in 2013 to 4,797 billion kWh in 2040. The average annual increase of 0.8% from 2013 to 2040 is slightly below the 1.0% annual rate in the AEO2014 Reference case. In all the end-use sectors, electricity demand growth is slower than projected in AEO2014, with the largest difference in growth in the residential sector.

Coal has traditionally been the largest energy source for electricity generation. However, the combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of environmental rules dampens future coal use in both the AEO2015 and AEO2014 Reference cases. Beginning in 2019, coal-fired electricity generation is between 2% and 4% percent higher in the AEO2015 Reference case than in AEO2014 through 2025, as a result of higher natural gas prices. After 2025, coal-fired generation remains between one and two percent higher in AEO2015 than in AEO2014 (Figure E6). The AEO2015 Reference case does not include the proposed Clean Power Plan[30] for existing fossil-fuel-fired electric generating units, which, if implemented, could substantially change the generation mix.

Coal accounted for 39% of total generation in 2013, and its share falls to 34% in 2040 in the AEO2015 Reference case. The coal share of total generation was lower at 32% in 2040 in the AEO2014 Reference case. With retirements of coal-fired generating capacity far outpacing new additions, total coal-fired generating capacity falls in the AEO2015 Reference case from 304 GW in 2013 to 260 GW in 2040, which is similar to the 2040 capacity projection in the AEO2014 Reference case.

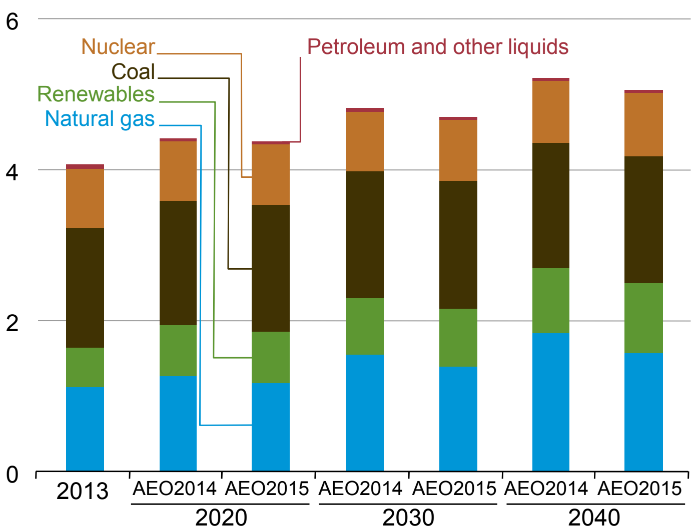
Electricity generation from natural gas grows at a slower rate in the AEO2015 Reference case than in the AEO2014 Reference case because of lower growth in overall electricity demand, higher natural gas prices in the midterm, fewer nuclear retirements, and more renewable capacity additions leading to less need for new natural gas-fired capacity. In the AEO2015 Reference case, natural gas-fired generation in 2040 is 15% lower than projected in the AEO2014 Reference case. Natural gas capacity additions still make up most (58%) of total capacity additions from 2014 to 2040 but represent a smaller share of new builds than the 74% of total additions projected in AEO2014. As a share of total generation, natural gas does not surpass the coal-fired generation share in the AEO2015 Reference case over the projection period as it did in the AEO2014 Reference case.

Increased generation from renewable energy accounts for 38% of the overall growth in electricity generation from 2013 to 2040 in the AEO2015 Reference case. Generation from renewable resources grows in the near term as new capacity under construction comes online in response to federal tax credits, state-level policies, and declining capital costs for wind and solar projects. In the final decade of the projection, renewable generation growth is almost exclusively the result of the increasing cost-competiveness of renewable generation with other, nonrenewable technologies.

Renewable generation is higher throughout most of the projection period in AEO2015 than was projected in AEO2014, and it is about 7% higher in 2040. Combined generation from solar and wind power in AEO2015 is about 28% higher in 2040 than projected in AEO2014, as a result of more planned renewable capacity additions and recent declines in the construction costs for new wind plants. Renewable generation accounts for 18% of total generation in 2040 in the AEO2015 Reference case, compared with 16% in AEO2014.

In the AEO2015 Reference case, electricity generation from nuclear power plants increases by 6%, from 789 billion kWh in 2013 to 833 billion kWh in 2040, and accounts for about 16% of total generation in 2040, slightly above the share in AEO2014. Over the projection period, nuclear generation in AEO2015 is on average 3% higher than projected in AEO2014, with about 4 GW less nuclear capacity retired from 2013 to 2020 in the AEO2015 Reference case, compared to the AEO2014 Reference case.

Figure E6. Electricity generation by fuel in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040 (trillion kilowatthours)



Energy-related CO2 emissions

Total U.S. energy-related CO2 emissions remain well below their 2005 level of 5,993 million metric tons (mt) through the end of the projection period in the AEO2015 Reference case.[31] Energy-related CO2 emissions in 2040 are 5,549 million mt, or 50 million mt (0.9%) below the AEO2014 Reference case projection. This decrease may appear counterintuitive, since coal consumption is 1.4% higher, petroleum and other liquids consumption is 2.4% higher, and total renewable energy consumption is lower, all putting upward pressure on emissions. However, natural gas consumption is 5.6% lower, and while it has a lower carbon factor than the other fossil fuels, it does emit CO2. Nuclear energy consumption in 2040 is 2.8% higher in AEO2015 than in AEO2014, and total energy demand is 0.5% lower. The net result is somewhat lower energy-related CO2 emissions in the AEO2015 Reference case than in the AEO2014 Reference case.

[30]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014) https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

[31]The year 2005 is the base year for the Obama Administration's goal for emission reductions of 17% by 2020. In the AEO2015 Reference case, energy-related CO2 emissions in 2020 are 8% below the 2005 level.

Figure and table sources

Links current as of April 2015

Table E1. Comparison of projections in the AEO2015 and AEO2014 Reference cases, 2012-40: AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E1. Average annual Brent crude oil spot prices in the AEO2015 and AEO2014 Reference cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E2. Delivered energy consumption by end-use sector in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E3. Primary energy consumption by fuel in the AEO2015 and AEO2014 Reference cases, 2013 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E4. Total energy production and consumption in the AEO2015 and AEO2014 Reference cases, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

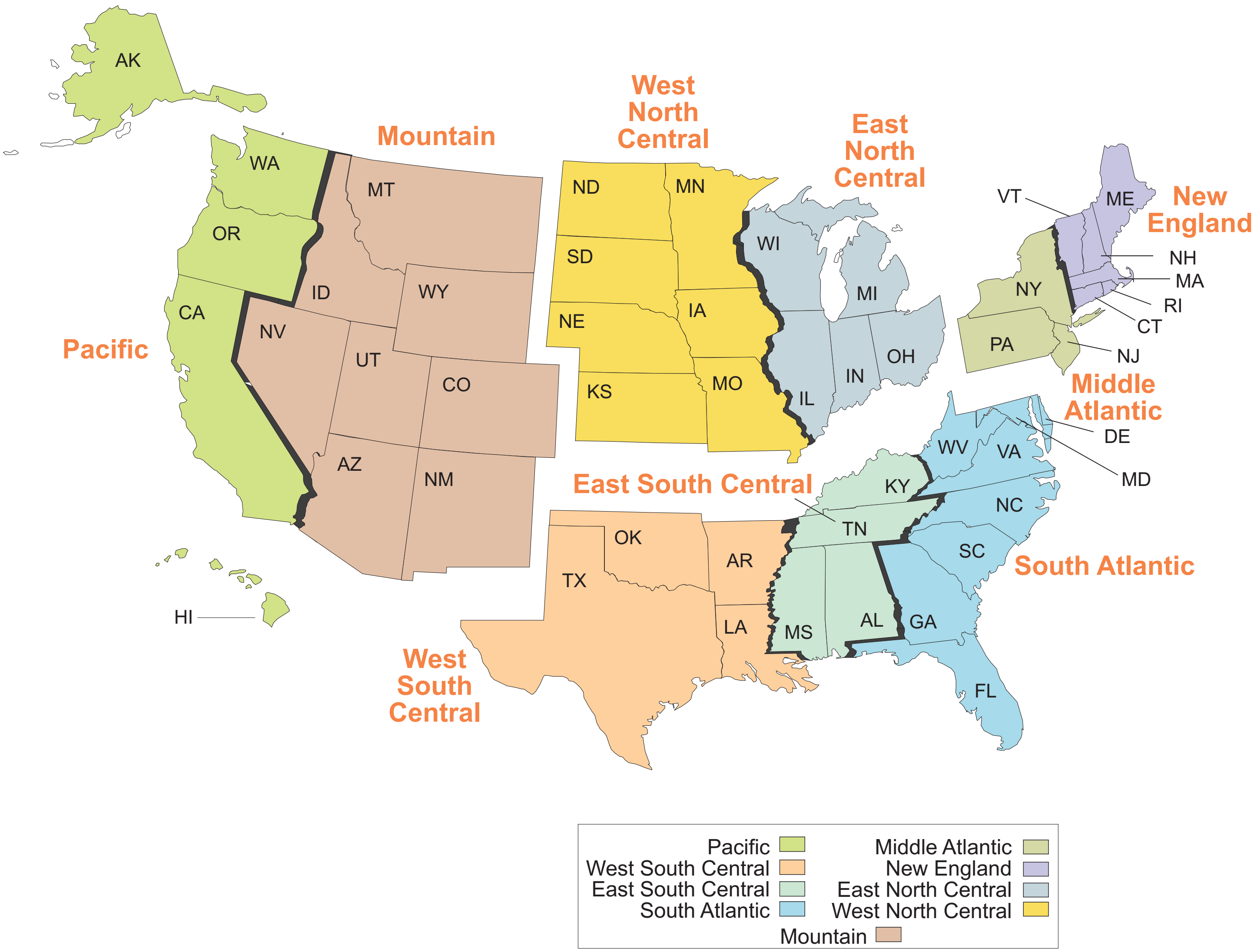
Figure E5. Share of U.S. liquid fuels supply from net imports in the AEO2015 and AEO2014 Reference cases, 1970-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E6. Electricity generation by fuel in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Appendix F

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F1. United States Census Divisions (continued)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

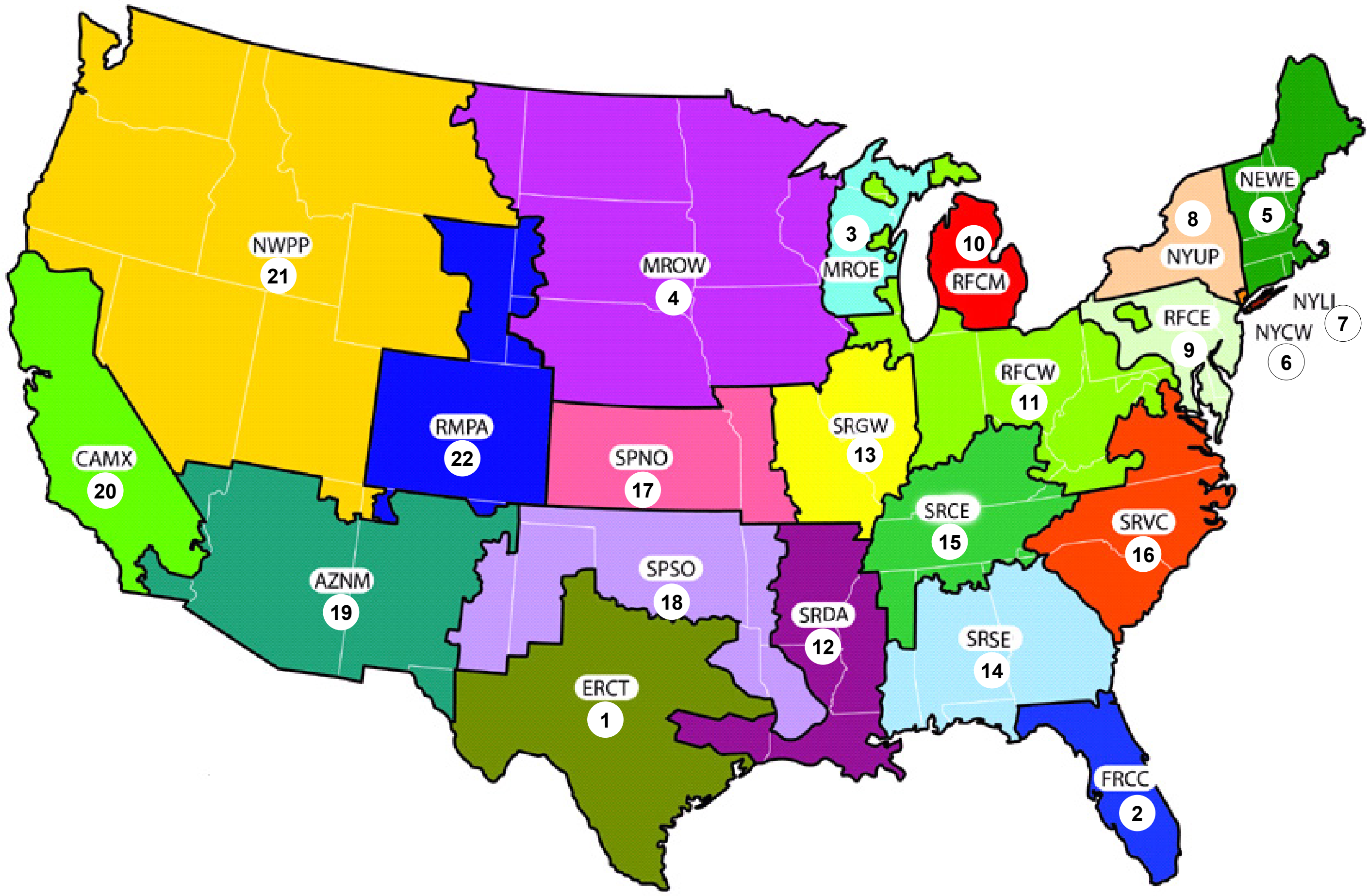
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

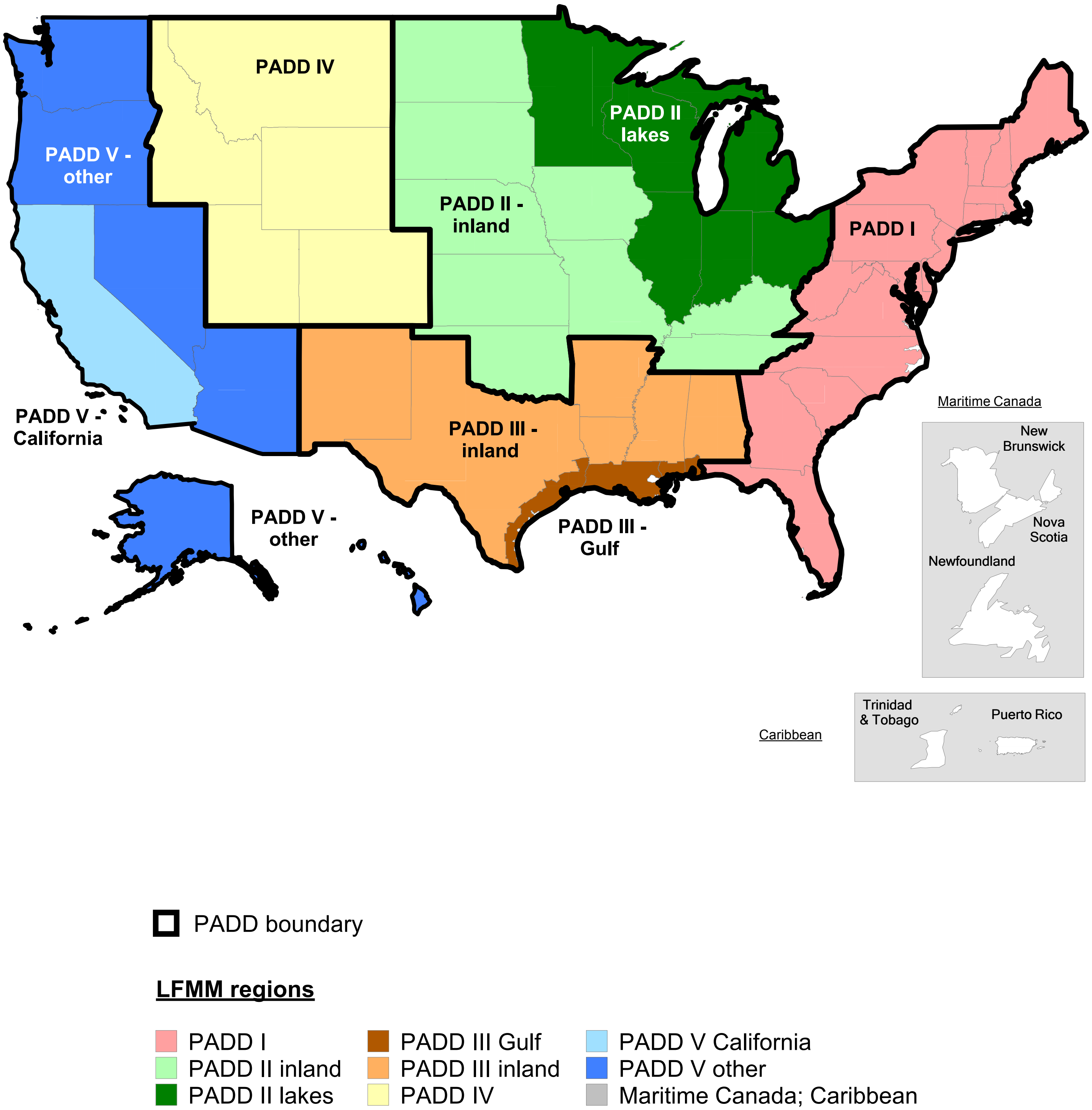
Figure F2. Electricity market module regions



1.	ERCT	TRE All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

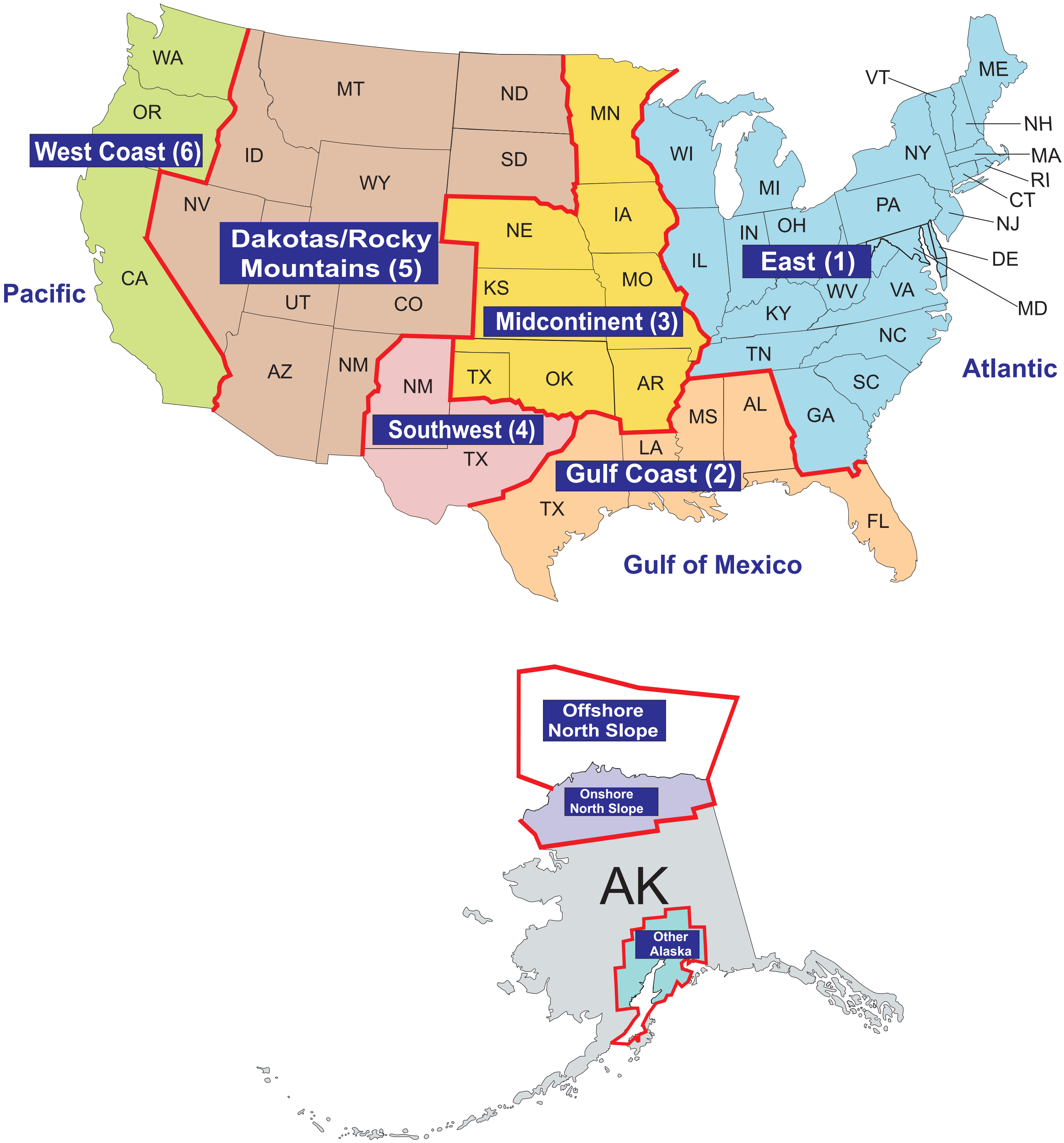
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F3. Liquid fuels market module regions



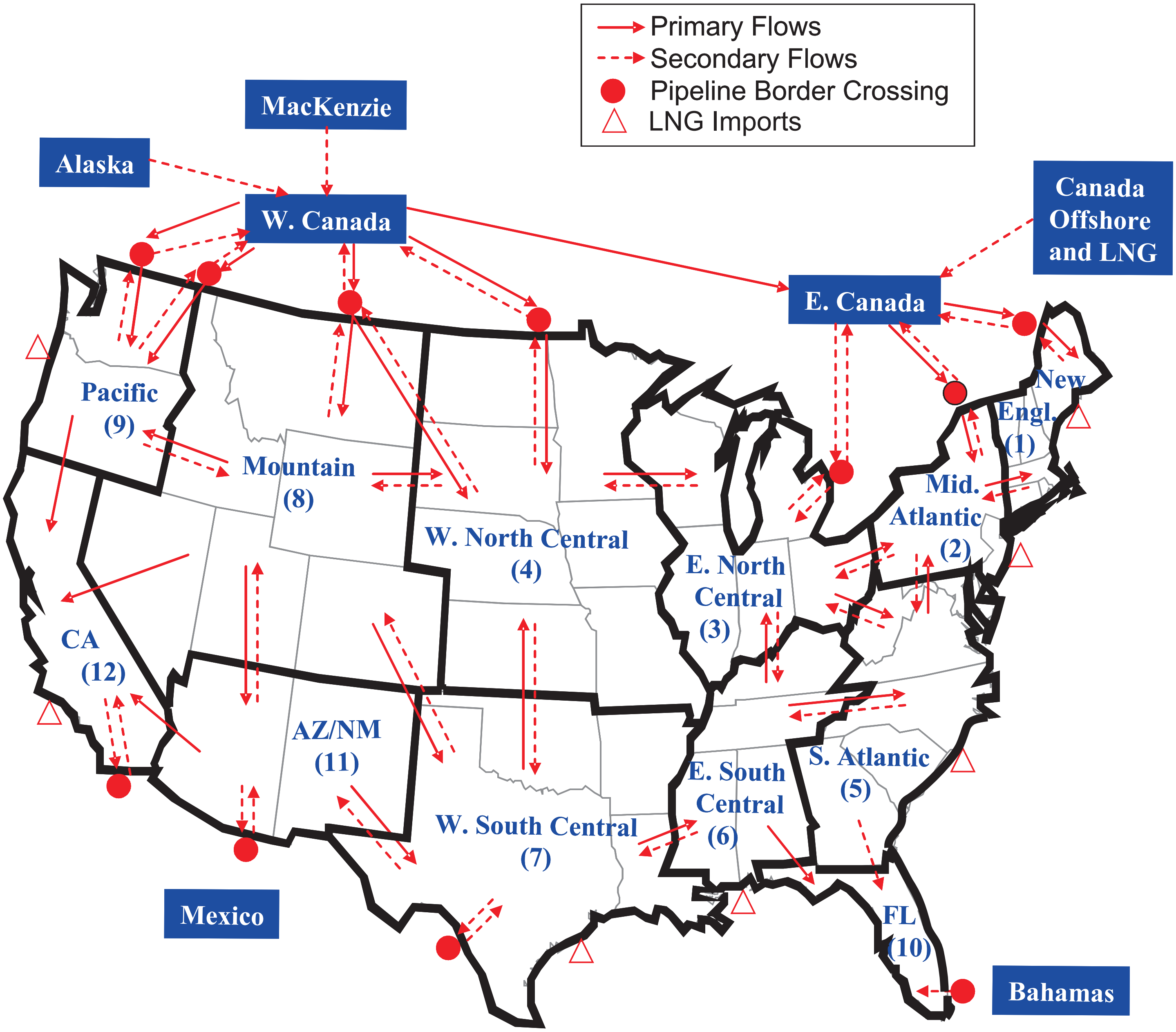
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions



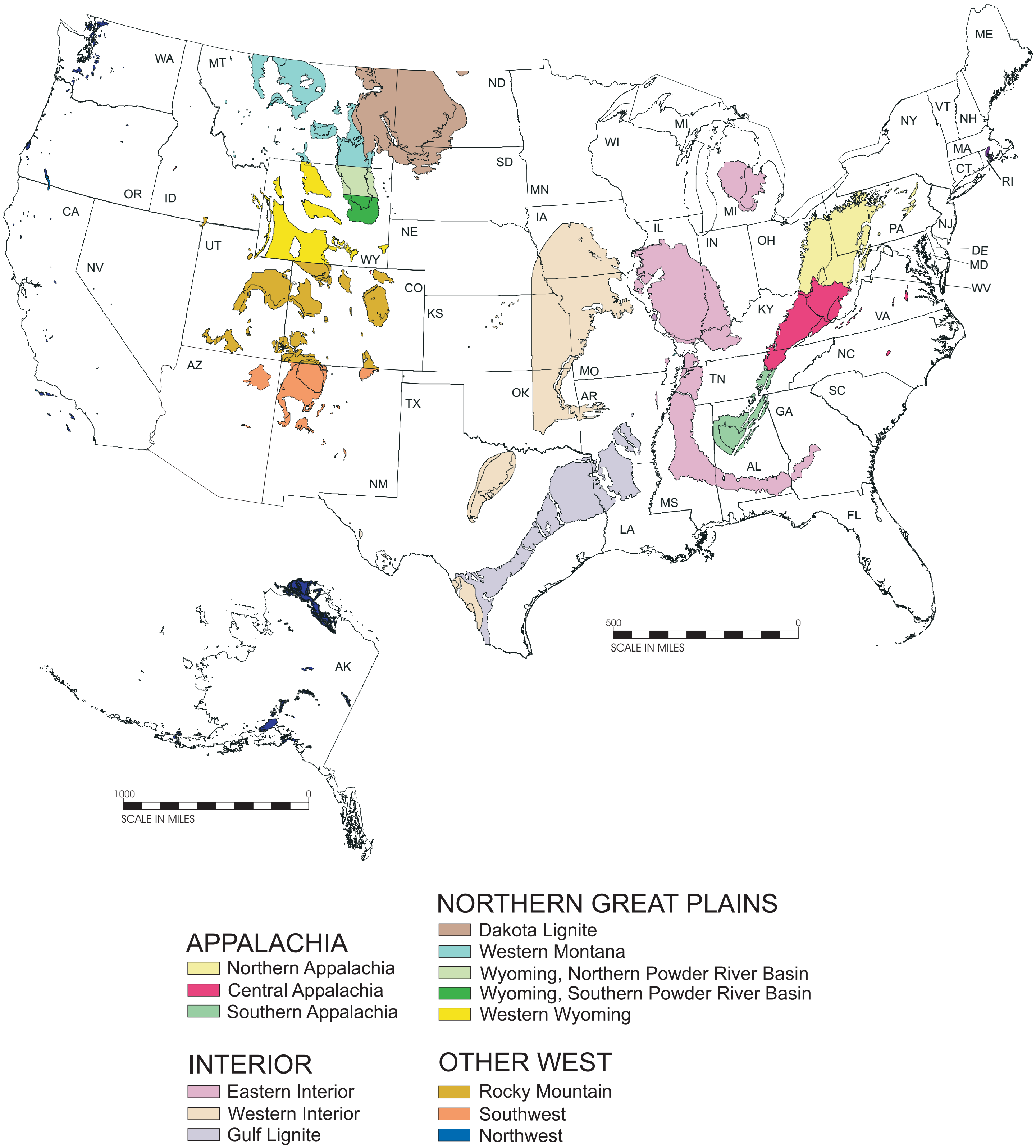
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



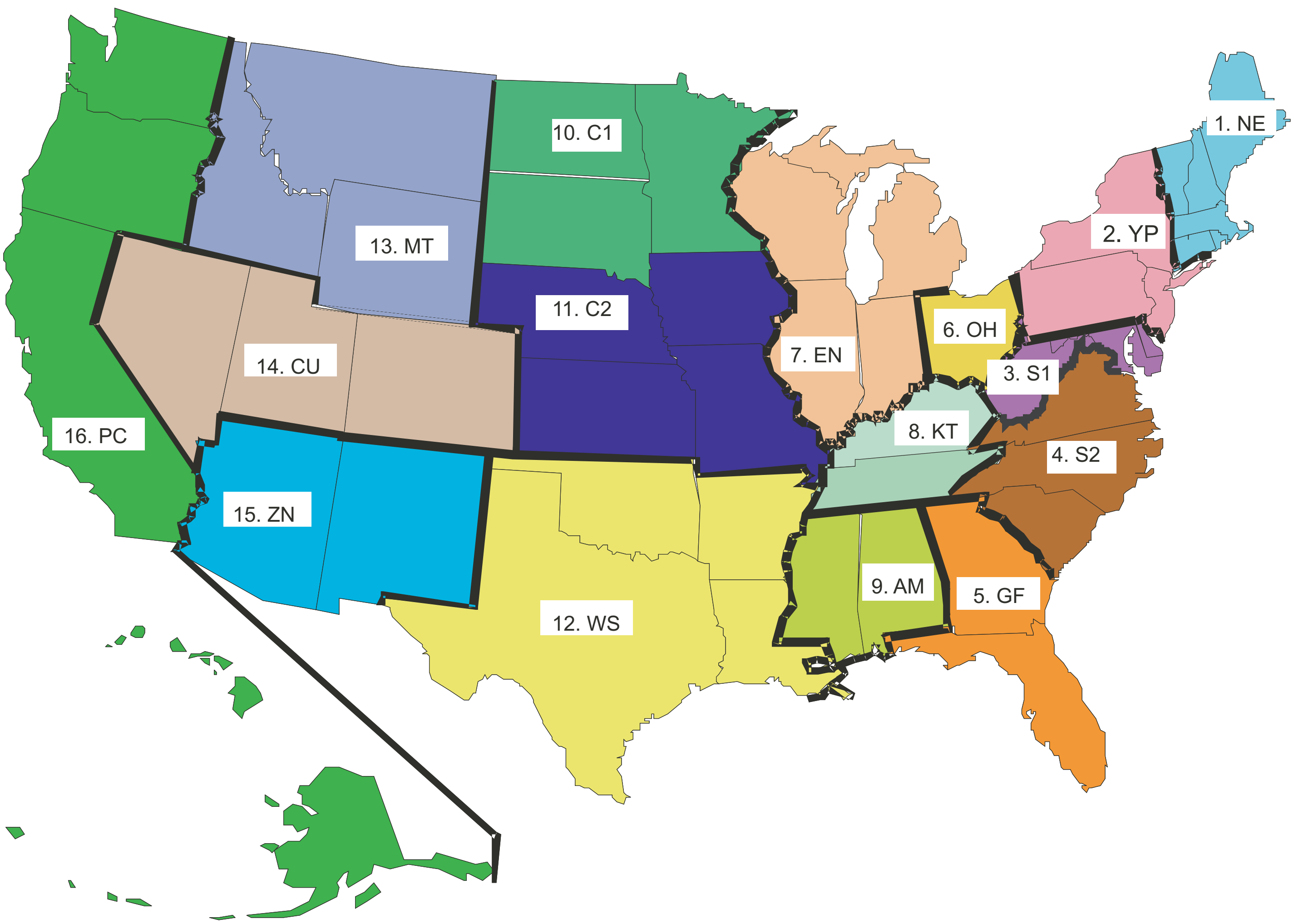
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F7. Coal demand regions



Region Code	Region Content	Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT	9. AM	AL,MS
2. YP	NY,PA,NJ	10. C1	MN,ND,SD
3. S1	WV,MD,DC,DE	11. C2	IA,NE,MO,KS
4. S2	VA,NC,SC	12. WS	TX,LA,OK,AR
5. GF	GA,FL	13. MT	MT,WY,ID
6. OH	OH	14. CU	CO,UT,NV
7. EN	IN,IL,MI,WI	15. ZN	AZ,NM
8. KT	KY,TN	16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Appendix G

Conversion factors

Table G1. Heat contents

Fuel	Units	Approximate heat content
Coal[1]		
Production	million Btu per short ton	20.169
Consumption	million Btu per short ton	19.664
Coke plants	million Btu per short ton	28.710
Industrial	million Btu per short ton	21.622
Commercial and institutional	million Btu per short ton	21.246
Electric power sector	million Btu per short ton	19.210
Imports	million Btu per short ton	23.256
Exports	million Btu per short ton	24.562
Coal coke	million Btu per short ton	24.800
Crude oil[1]		
Production	million Btu per barrel	5.751
Imports	million Btu per barrel	6.012
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.188
Motor gasoline[1]	million Btu per barrel	5.101
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.760
Diesel fuel[1]	million Btu per barrel	5.755
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases and other[1,2]	million Btu per barrel	3.565
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	4.944
Unfinished oils[1]	million Btu per barrel	6.098
Imports[1]	million Btu per barrel	5.575
Exports[1]	million Btu per barrel	5.506
Ethanol[3]	million Btu per barrel	3.559
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids[1]		
Production	million Btu per barrel	3.735
Natural gas[1]		
Production, dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,027
End-use sectors	Btu per cubic foot	1,028
Electric power sector	Btu per cubic foot	1,025
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2013.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes denaturant.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014), and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Is someone front-running you around news releases?

By Irene Aldridge

Able Alpha Trading, LTD., AbleMarkets.com and BigDataFinance.org

irene@ablemarkets.com

This Draft: February 5, 2016

Abstract

This study presents evidence that much of the trading on macro-economic news occurs prior to the scheduled news announcement times. Examining the trading patterns ahead of the ISM Manufacturing Index and Construction Spending announcement, we find that the trading on the not-yet-publicly released embargoed news consistently takes place as long as 30 minutes ahead of the news announcement times. The aggressive HFTs appear to be involved in the pre-announcement trading. In fact, as much as three quarters of the pre-announcement price move appears to be driven by aggressive HFTs.

Keywords
News events, front-running, news leakage, high-frequency trading, institutional investors

Introduction

It is no secret that news moves the markets. According to the rational expectations hypothesis, news is the only thing that moves the markets; everything else is noise. Companies like Bridgewater Associates have built small empires with annual revenues exceeding the GDPs of small countries combined just following, interpreting and acting upon the news. Not surprisingly, the question of whether news announcements are released in a fair manner remains a hot topic. Even less surprising, the fairness of news releases has surfaced as one of the key concerns associated with high-frequency trading. Specifically, some market participants have accused high-frequency traders of using fast technology to front-run lower-speed traders following major news announcements. This research considers market activity surrounding news events.

Event studies are a classic way to measure the happenings surrounding news announcements. According to MacKinlay (1997), the event study methodology is as established as the science of Finance, dating back to the 1930s. An event study compares the impact of the news on market conditions before and after the event, in what's known as an "event window". The window can be as large or as small as one may like it to be, provided that there are enough data points in the selected window and that the distribution of the dependent variable matches the selected analysis model (see Mucklow, 1994, among others). Given the short-term behavior of aggressive HFT, described in detail in Aldridge (2013), we will need to focus on smaller time windows to consider the behavior of aggressive HFTs around a news announcement.

Choosing the event is another matter, no less important than the selection of the event window. One factor to consider is that many news announcements are scheduled outside of regular trading hours. To examine the short-term HFT activity around news announcements, however, we consider news that was a) released during common market hours, b) likely to generate a similar reaction across many financial instruments at once.

One such news is Construction spending, computed by the U.S. Census Bureau. It estimates the total value of construction performed in the United States during the previous month, including labor, materials, architecture and engineering costs, overhead, interest and even taxes. The index covers construction in both public and private sectors. Construction spending is an indicator of economic optimism. The higher the construction spending, the reasoning goes, the more people are investing into long-term projects, the higher is the optimism about the economy's future.

Construction spending announcements often coincide with ISM Manufacturing Index survey figures. The ISM Manufacturing Index, published once a month by the Institute of Supply Management is located in Temple, Arizona. ISM asks over 300 manufacturing firms about their employment, production inventories, new orders and supplier deliveries, and creates a composite reflecting the current manufacturing conditions. An index increase tends to signal better manufacturing conditions, translating into a pick-up in the economic growth. Conversely, a decrease in the index potentially signals a flagging economy.

The present research analyzes the two events in tandem and uses the latest event study methodology to separate the impacts of the two announcements and the aggressive HFT behavior on the returns.

Stylized Facts

On July 1, 2015, the month-to-month change in Construction Spending and ISM Manufacturing Index were reported at 10:00 AM. According to Bloomberg, Construction Spending had increased by 0.8, beating analysts' consensus forecast of a 0.5 increase by 0.3. The simultaneously-reported ISM Manufacturing Index value was 53.5, an increase of 0.8 from the value reported in June and a 0.3 improvement over "consensus forecast," a composite figure aggregating opinions of a range of economists polled by Bloomberg on the matter. The news was good. The economy was observed to be growing, and stocks were expected to go up.

The 10:00 AM announcements were preceded by a 9:45 AM value of Purchasing Managers' Manufacturing Index ("PMI Manufacturing Index"). The index, computed by Markit in collaboration with the Institute of Supply Management, is based on the responses to the questionnaires sent out to managers in selected companies. The 9:45 AM figures were worse than expected and worse than the prior month's figures.

Figure 1 shows the minute-by-minute cumulative price response to news by Agilent Technologies (NYSE:A) recorded on BATS-Z exchange. As Figure 1 shows, in the 60-minute time interval prior and immediately following the news announcement, the biggest growth in price occurred nearly ½ hour ahead of the news release, just after the market open. The stock price of Agilent appears to be unaffected by the PMI Index values made public at 9:45 AM, 15 minutes prior to the 10:00 AM event.

Figure 2 shows the proportion of aggressive HFT activity by volume traded in Agilent around the news announcement, as estimated by AbleMarkets. As Figure 2 shows, aggressive HFT buying activity peaked at market open, and again nearly ½ hour following the news announcement. Aggressive HFT selling activity was elevated around 10:13 AM, potentially explaining some of the observed post-announcement sell-off in NYSE:A. The aggressive HFT numbers immediately surrounding the event announcement may have been dampened by the influx of trading volume brought on by other market participants: institutions and retail looking to capitalize on the news.

Is the behavior of the price of A an anomaly? Is the pre-announcement gain a random occurrence? To answer this question, we looked at the price response of the entire Russell 3000 index to the same announcement, ISM Manufacturing Index report on July 1, 2015. Using BATS-Z data, and averaging the cumulative dollar gains and losses of each of the Russell 3000 stocks each minute, we arrive at an even more pronounced pre-announcement market movement pattern shown in Figure 3. In fact, across all the Russell 3000 stocks, the pre-announcement price movement is so pronounced and precise, that very little volatility can be observed after the announcement, as Figure 4 shows. Figure 4 quantifies volatility by measuring the cross-sectional dispersion of returns each minute across all Russell 3000 stocks. As Figure 4 shows, volatility indeed declines dramatically following the news announcement.

The minute-by-minute average of the aggressive HFT activity for the entire set of stocks comprising the Russell 3000 surrounding the events of 10:00 AM on July 1, 2015, is equally interesting: the aggressive HFT buyers dominated sellers from 9:45 until the 10:00 AM news announcement, at which point relative proportion of aggressive HFT dropped dramatically from the 20-30% range to single digits, as shown in Figure 5.

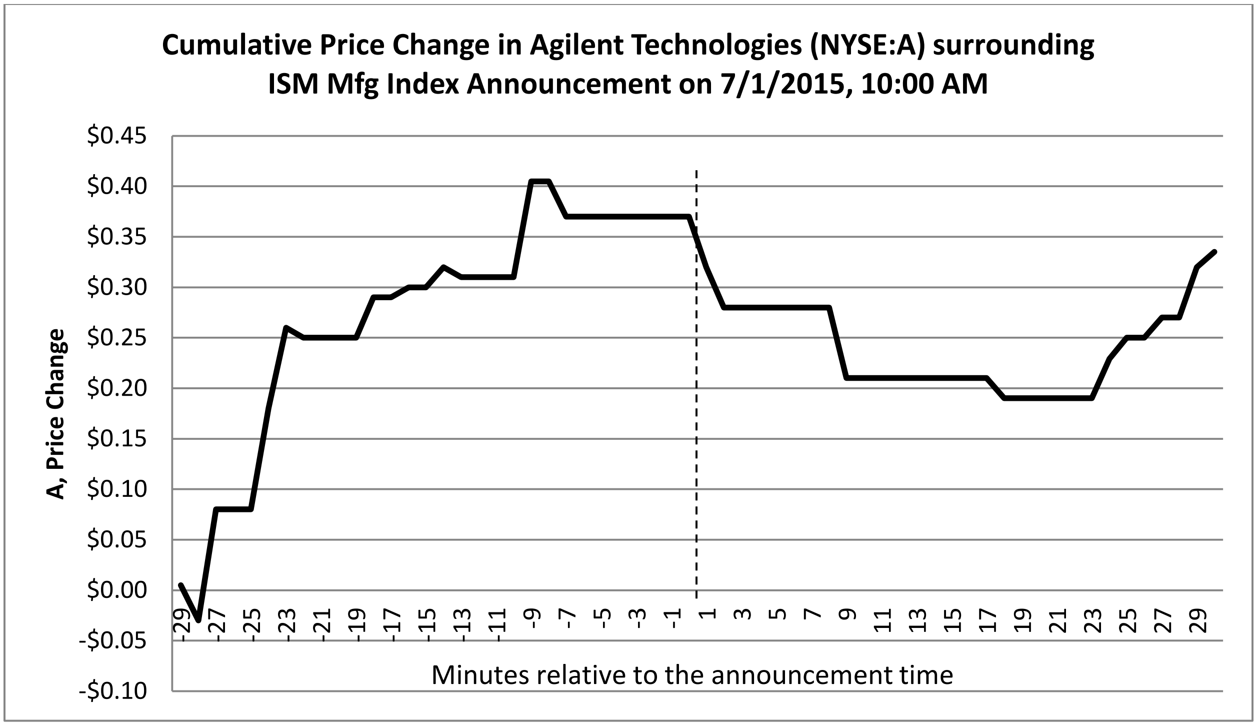


Figure 1. Cumulative price change of Alcoa (NYSE:A) surrounding the 10:00 AM ISM Manufacturing Index announcement recorded in BATS-Z on July 1, 2015.

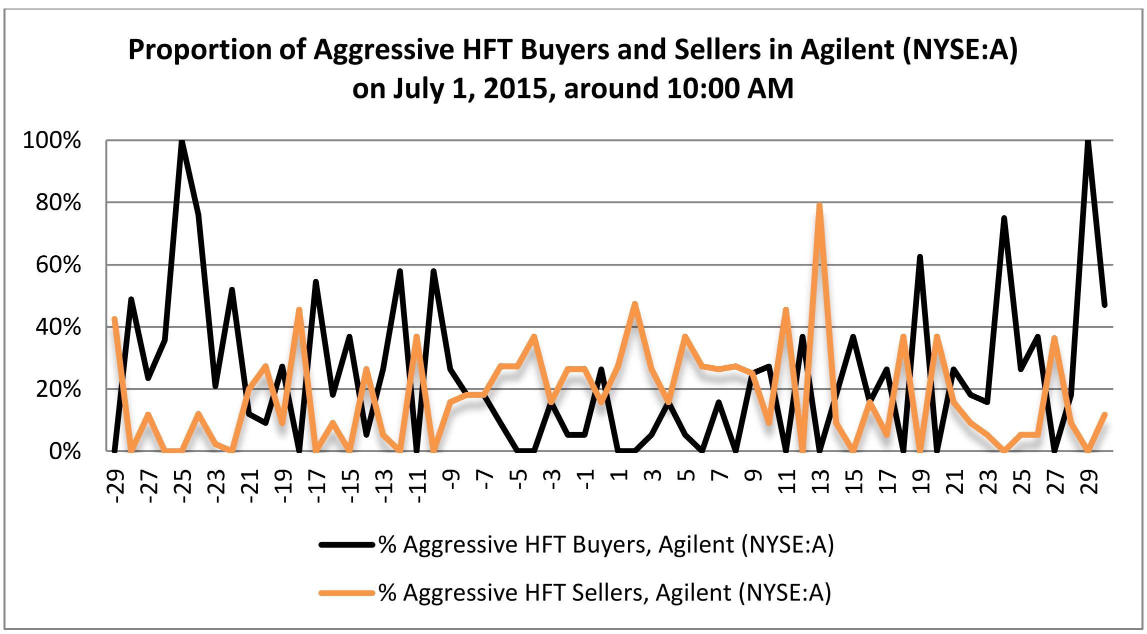


Figure 2. Participation of Aggressive HFT by Volume in Agilent (NYSE:A) on July 1, 2015, before and after the Construction Spending figures announcement at 10:00 AM.

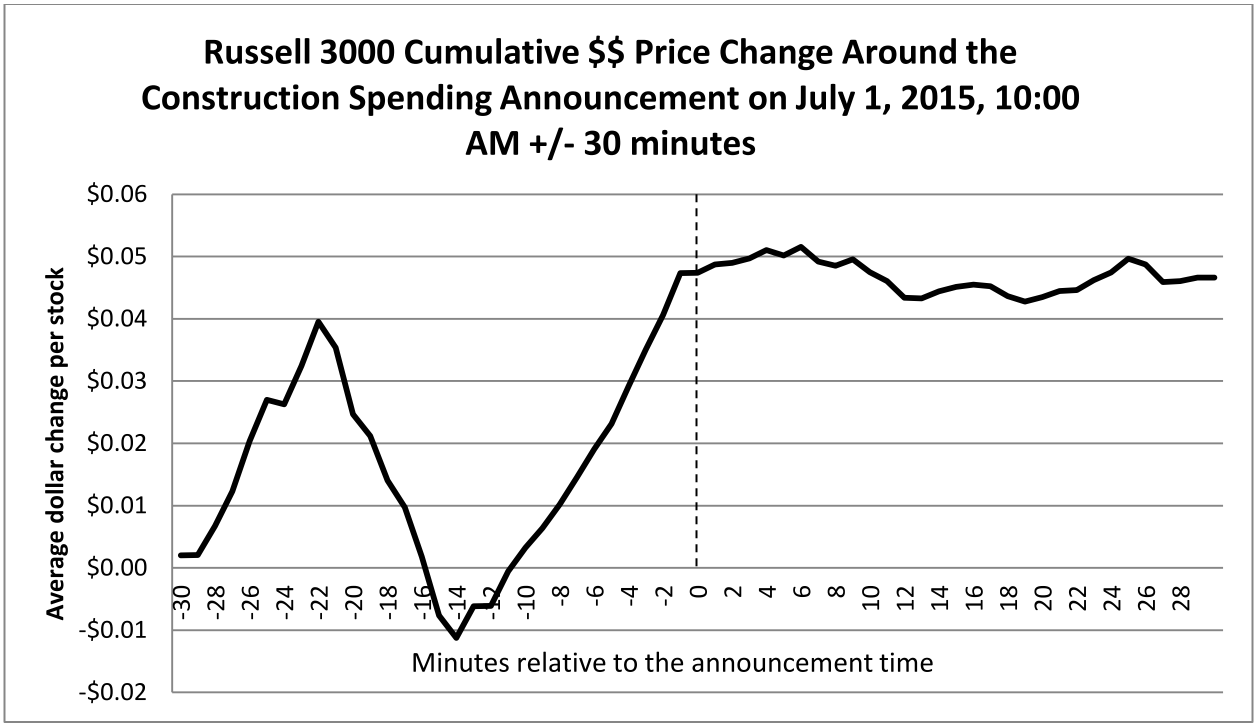


Figure 3. Average Cumulative Price Change for All the Russell 3000 stocks surrounding Construction Spending Announcement at 10:00 AM on July 1, 2015.

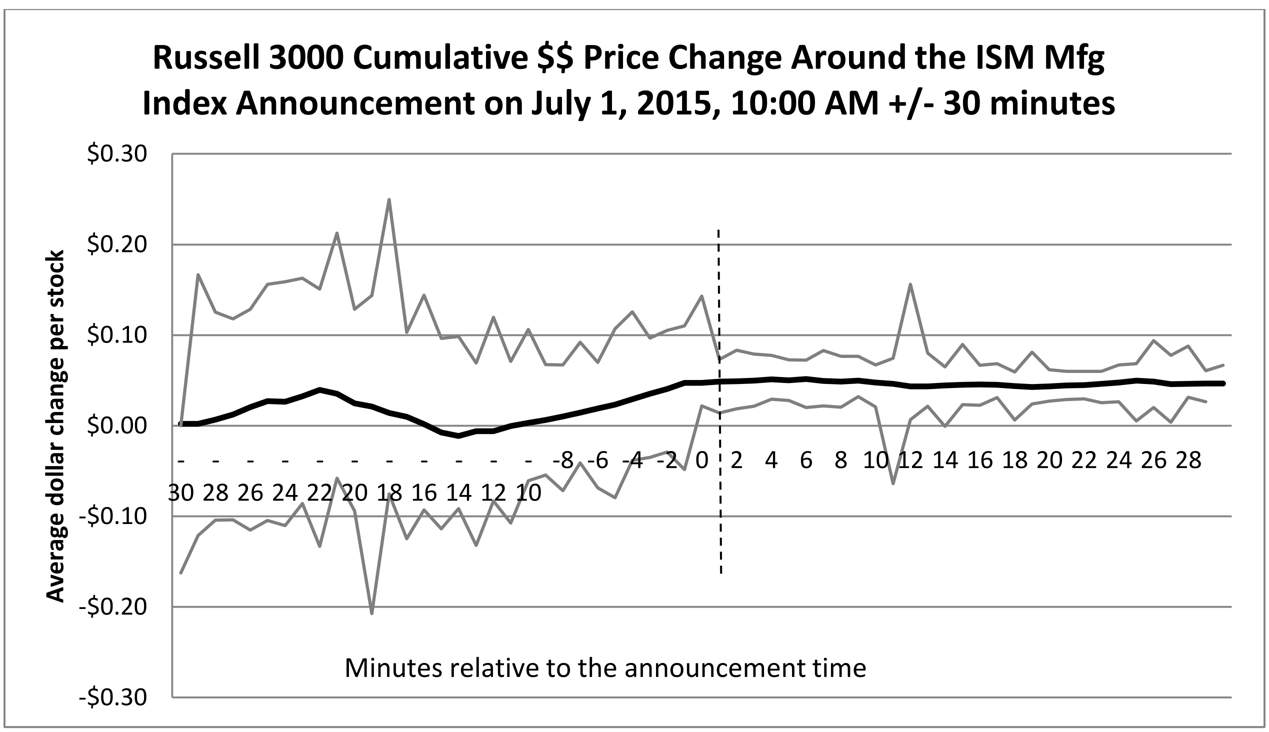


Figure 4. Average Cumulative Price Change and Price Change Volatility across All the Russell 3000 stocks surrounding Construction Spending Announcement at 10:00 AM on July 1, 2015.

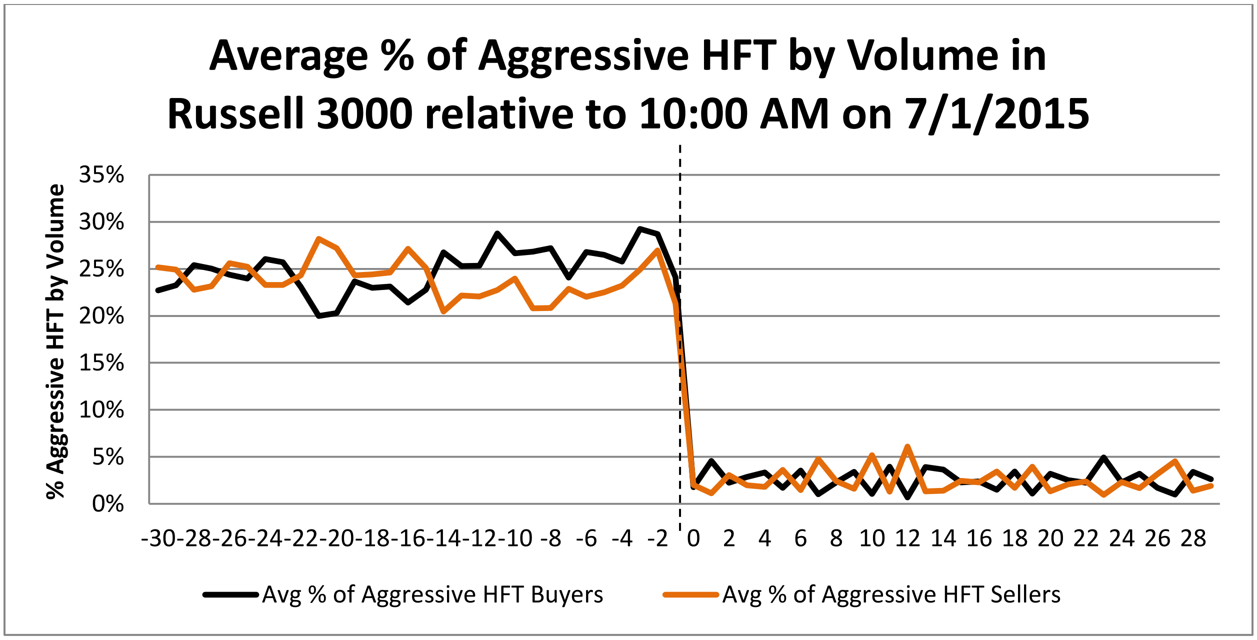


Figure 5. Participation of Aggressive HFT averaged across all Russell 3000 stocks around 10:00 AM news on July 1, 2015.

Putting aside aggressive HFT behavior for a moment, let's consider what is wrong with the pictures of Figure 3 and Figure 4. According to classical finance, markets are not supposed to move in response to an announcement as most of the news is priced in prior to the news announcement. Specifically, the news is incorporated into prices through a trading process, with trades carrying information to the market with traders acting on their beliefs and "putting their money where their mouths are." It would seem that according to the rational expectations hypothesis, therefore, the markets are operating normally, except that the rational expectations hypothesis is expected to work over the days and weeks preceding the event announcement, not minutes. The apparent furious trading just ahead of the announcement time is puzzling at best.

According to yet another pillar of classical finance, the efficient markets hypothesis (Fama, 1970), the incorporation of news depends on the "universe" of the news: whether the news is public or private. News that is public and is, therefore, known to a large number of traders, is incorporated into the markets nearly instantly, while the news that is not widely known tends to seep into the markets slowly. In theory public announcements, like the ISM Manufacturing Index, are not available for distribution until their precise release time. After the embargo ends, related stocks should experience a clean "step" in price action similar to the one shown in Figure 6 for positive news and Figure 7 for negative news. Under the Efficient Markets Hypothesis, the price neatly follows the rational expectations hypothesis, fully incorporating all the publically available news just before and immediately following the news release. With these situations, there are no gradual price transitions.

The efficient market hypothesis, however, allows for selected public news, like the ISM Manufacturing Index value, to be estimated by economists. The economists' thinking, in turn, could gradually filter into the pricing through trading, but would not result in a concerted price action. Instead, copious research shows that, whenever public news is released, the price undershoots just before the news announcement, and overshoots temporarily just after the announcement, as shown in Figures 8 and 9.

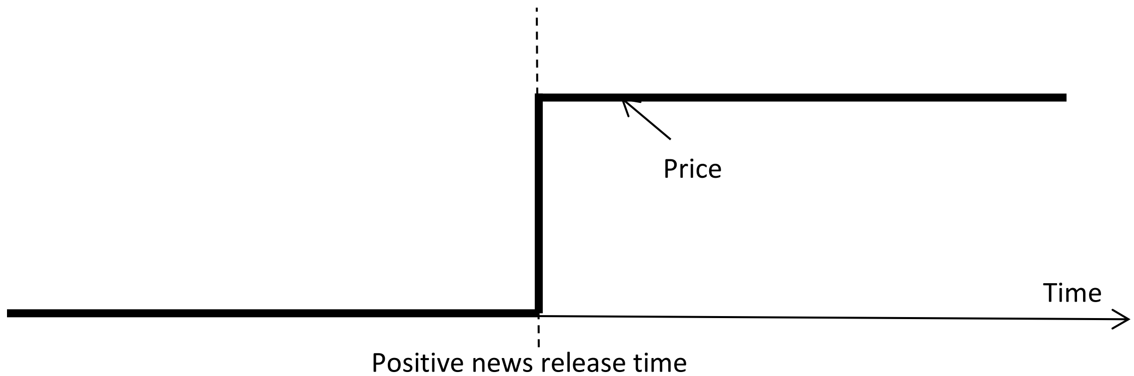


Figure 6. Instantaneous price adjustment in response to positive publically-released news, according to the efficient markets hypothesis.

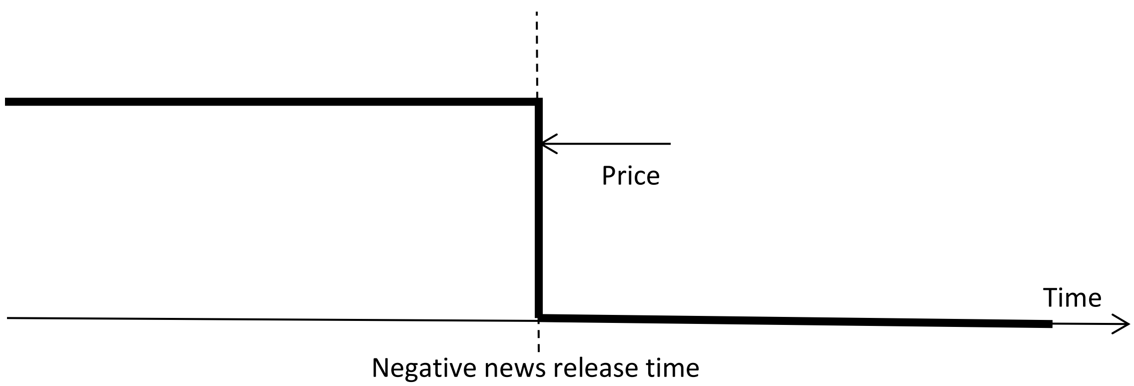


Figure 7. Instantaneous price adjustment in response to negative news, according to the efficient markets hypothesis.

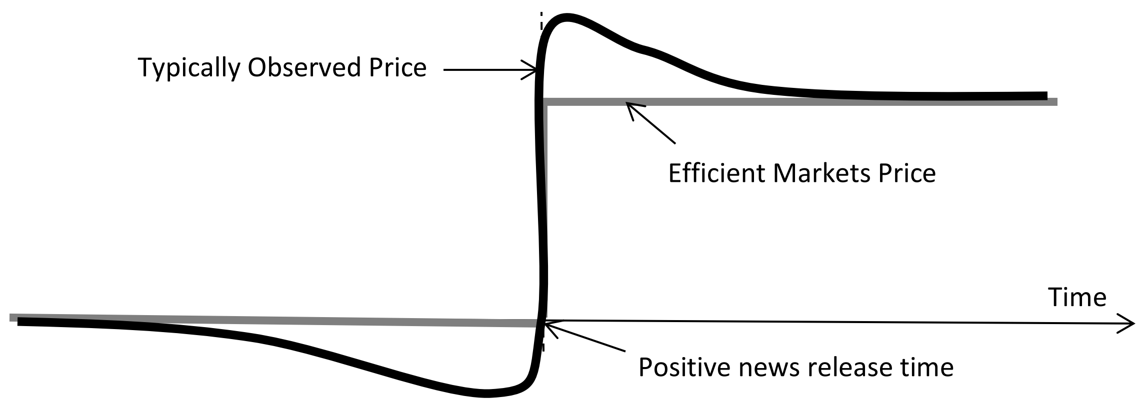


Figure 8. Actual price adjustment in response to positive publically-released news, according to behavioral studies.

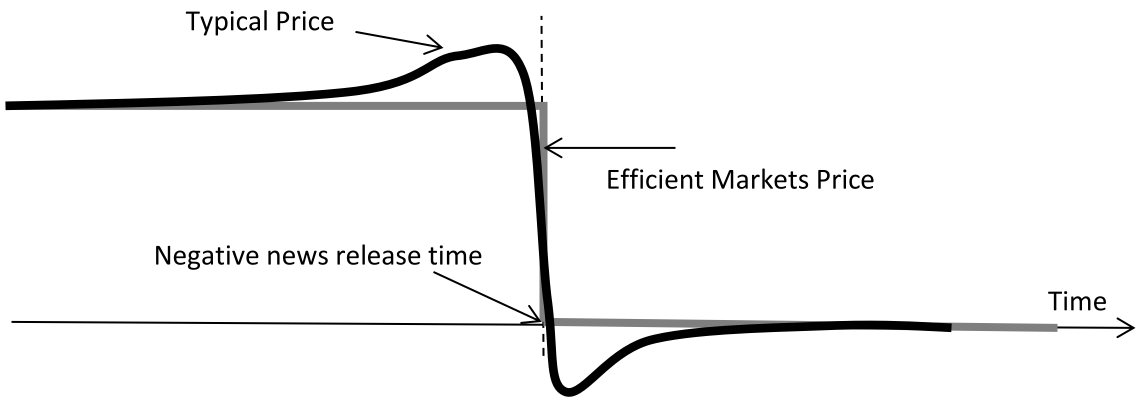


Figure 9. Actual price adjustment in response to negative news, according to behavioral studies.

Furthermore, the theory of rational expectations suggests that the upcoming news is priced in the markets long before the announcement. One way it may be priced in is by trading on the summary forecasts of a cohort of economists polled by Bloomberg or other forecasting services ahead of the announcement. The average of these estimates in considered to be a “consensus forecast.” While the consensus forecast may not be perfect, it can be fairly informative. For the ISM Manufacturing Index, for example, the consensus forecast predicted the correct direction of the index (increase or decrease from the prior month) 79% of time from 2010 through 2015, and 83% of time from 2013 through 2015.

As shown in Figures 3 and 4, market behavior of the Russell 3000 stocks had little to do with the market responses expected under the Efficient Markets and Rational Expectations Hypotheses. The average price of the Russell 3000 stocks began to rise 15 minutes prior to the news announcement, and barely moved after the news is released at 10:00 AM.

How can market behavior and that of aggressive HFT be explained in a sensible manner? Some market participants have blamed aggressive HFTs for obtaining news and acting upon it ahead of its release to the public. While the assumption of advanced knowledge is tenuous, it is not impossible due to an outdated concept of news embargo. News embargo emerged in the 1960s as a solution to the issue of news fairness raised by market participants. To ensure wide access to news, the figures were to undergo the fullest possible distribution, which at that time, equaled television, radio and print. To provide adequate time for television and radio broadcast preparation, the news sources embargoed the news content for 1 hour, allowing all the news outlets to broadcast in unison ensuring equal access to all investors. The embargo system, however, has always been voluntary, and no government penalties of any sort exist for cases where a reporter decides to inappropriately email the news to a hedge-fund or an HFT friend of his. Given all the financial incentives the often-starving reporters may violate the embargo and share the news with a hedge funds or trading desk that can trade on the embargoed news.

What can be done to ensure fairness in the financial markets? Perhaps catching up with the times and distributing news via social media may do the trick – after all, most traders today are capable of making fundamental stock pricing calls on the basis of the released news figures alone, and do not require a reporter's interpretation of the figures. Why not release the news via Twitter or other social media and eliminate the now-ancient embargo process?

Decades-old changes to the news distribution process, however, may take years to complete. In the meantime, investors of all stripes may choose to follow the markets dynamics and observe aggressive HFT behavior in an effort to extract the information about upcoming events directly from the markets. Thus, for example, observing elevated levels of aggressive HFT buyers prior to the 10:00 AM news on July 1, 2015, would suggest that the about-to-be-formally-released news is likely to be positive. With a 15-minute lag prior to the news announcement, such observations do not require high-speed technology, yet deliver powerful predictability and, as a result, profitability.

Data, Methodology and Hypotheses

Deploying event-study methodology on ISM Manufacturing Index announcements from January 2013 through October 2015, we analyze movements of price, volatility and aggressive HFT activity around the news release. The results are interesting and surprising, or not so much, depending on whom you ask:

1. The news is "leaking" into the markets well prior to the news announcement.
2. Aggressive HFTs do appear to be trading on the news pre-announcements. However,
    a. The aggressive HFTs comprise only a portion of observed trading activity, and

b. The aggressive HFT activity can be due to institutions using aggressive HFT strategies to trade. While aggressive high-frequency trading activity appears to contribute to pre-announcement news incorporation in the markets, it is not the overwhelming factor in the pre-announcement trading activity.

How do we know that the news is leaking into the markets well ahead of the proper news announcement time? Consider Figure 10 which shows the cumulative price move in minutes for ISM Manufacturing Index before and after the actual time the news is released, averaged over the following two dimensions:

1) All the ISM Manufacturing Index announcements from January 2013 through October 2015
2) All the stocks in the Russell 3000

Figure 10 shows three lines:

1. The average cumulative price across all the event announcements and all the Russell 3000 stocks
2. The average cumulative price across only those ISM Manufacturing Index news release dates where the announced ISM Manufacturing Index values were higher than those announced in the immediately preceding month (Avg Cum+).
3. The average cumulative price across only those ISM Manufacturing Index news release dates where the announced ISM Manufacturing Index values were strictly lower than those announced in the immediately preceding month (Avg Cum-).

As Figure 10 demonstrates, as expected, a rise in ISM Manufacturing Index leads to higher stock prices across the entire Russell 3000 set. However, the price increase in response to positive announcements is not at all as one expects (shown in Figures 6 and 8). Instead of the concentrated price response around the news announcement itself (time 0 in Figure 10), the prices begin to move right at the market open (9:30 AM). The market moves as much as ½ hour ahead of the news release. This analysis points to a news leak that is way ahead of the scheduled news release time. The observed “dip” in prices at time -15 in Figure 10 is likely due to the price response to a preceding news announcement occurring at 9:45 AM. As expected, on average, across all the announcements, the price changes little, as indicated by the AVG line.

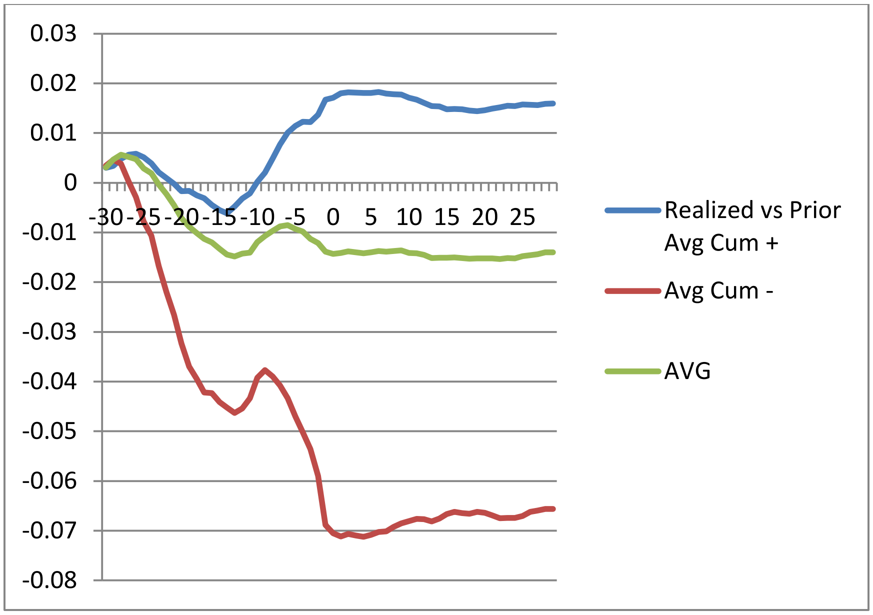


Figure 10. Average Price Response of the Russell 3000 Stocks to the ISM Manufacturing Index news from January 2013 through October 2015 (34 news announcements). The price impact is measured separately for cases when the value of the realized news is higher than the previous month's news, lower than the previous month's news and across all the cases.

How persistent are the observed price responses across various announcements? What if a move for a single announcement dominates the entire dynamic? Would the rest of the announcements generate a proper response? To answer this question, we look at the ratio of averages shown in Figure 10 to standard deviation of minute-by-minute price responses across different announcements across all the Russell 3000 stocks. Figure 11 shows the standard deviations, and Figure 12 presents the t-ratios: the averages of Figure 10 divided by the standard deviations of Figure 11.

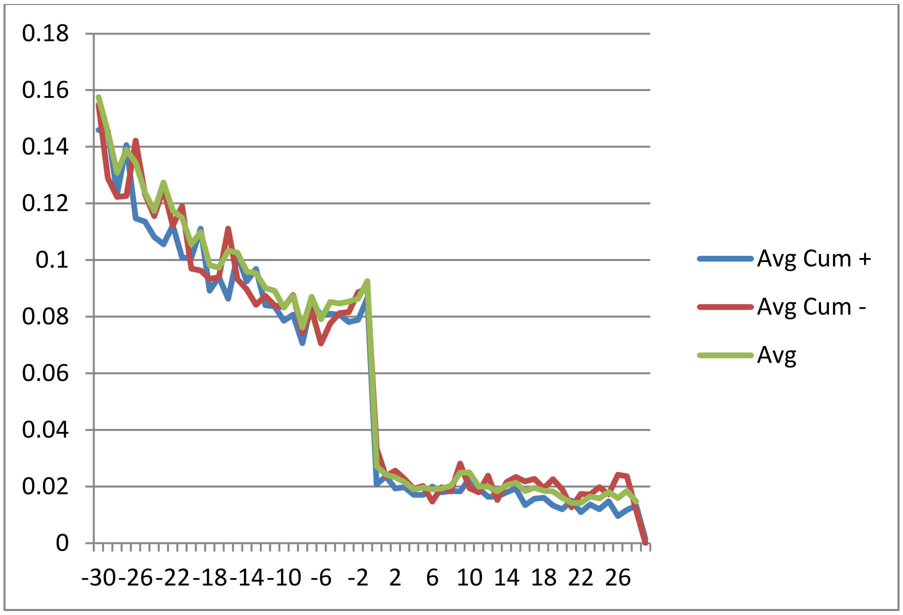


Figure 11. Standard deviation of average Russell 3000 cumulative price responses surrounding ISM Manufacturing Index announcements. Shown price volatility is measured for cases where the realized news was higher than the prior month's news, lower than the prior month's news and across all the cases.

As Figure 11 shows, the variation in price responses is the highest just before the scheduled news announcements, and the lowest following news announcements. However, the variation in the price response also happens to be low about 21 and 8-5 minutes *prior* to the proper news announcement time, 10 AM. The consistency of correct "guesses" of the impending news direction is so high that it is highly unlikely to be purely accidental.

Figure 12 displays the t-statistics of the cumulative price responses (averages of Figure 10 divided by the standard deviations of Figure 11). While, as shown in Figure 12, the response is much more statistically significant after the news announcement, it is still reaches 99.9% significance at least 10 minutes prior to the official news announcement time.

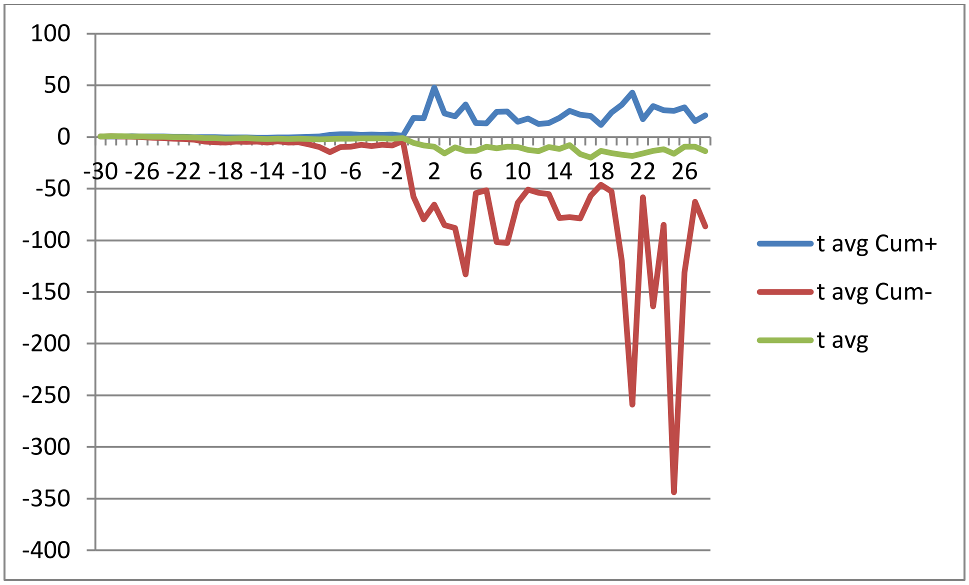


Figure 12. The t-ratios of the cumulative price responses of the Russell 3000 stocks around the ISM Manufacturing Index announcements.

What about the Construction Spending announcements that occur at the same times as the ISM Manufacturing Index? Figure 13 shows the average price to the realized vs. prior month change in the Construction Spending value. As Figure 13 shows, the response to Construction Spending is much more convoluted than it is to the ISM Manufacturing Index.

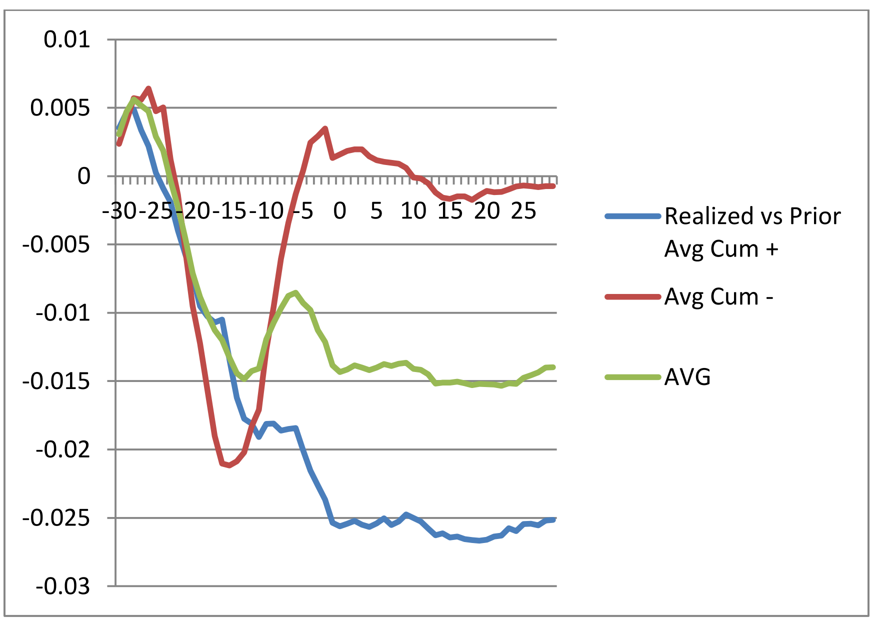


Figure 13. Average price response of the Russell 3000 stocks to the changes in Construction Spending relative to the prior month's announcements. Many times, the Construction Spending figures remained unchanged relative to their prior values.

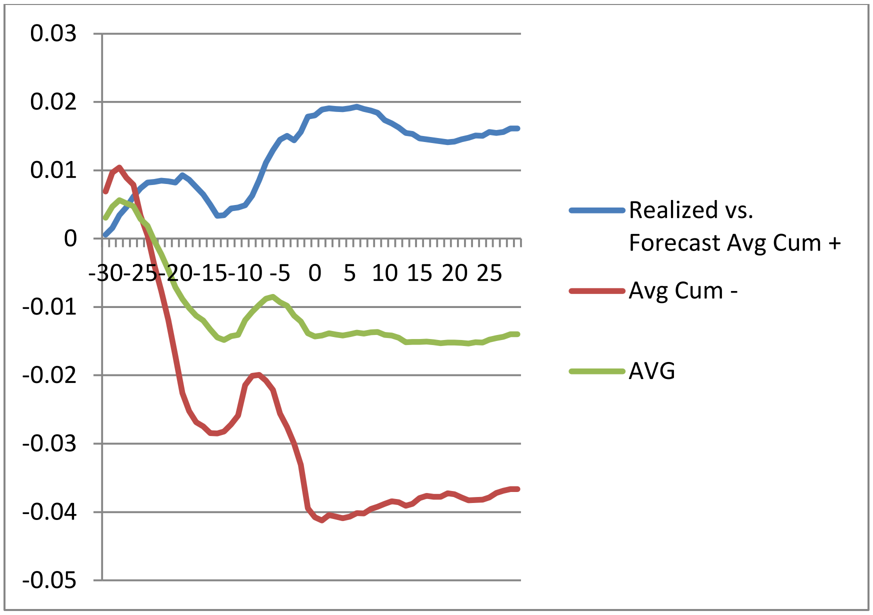


Figure 14. Average price response across the Russell 3000 stocks in response to 1) realized ISM Manufacturing Index spending exceeding consensus forecast ("Avg Cum+"), 2) realized ISM Manufacturing Index falling below the consensus forecast for that day ("Avg Cum-") and in response to all cases. Data covers January 2013 – October 2015.

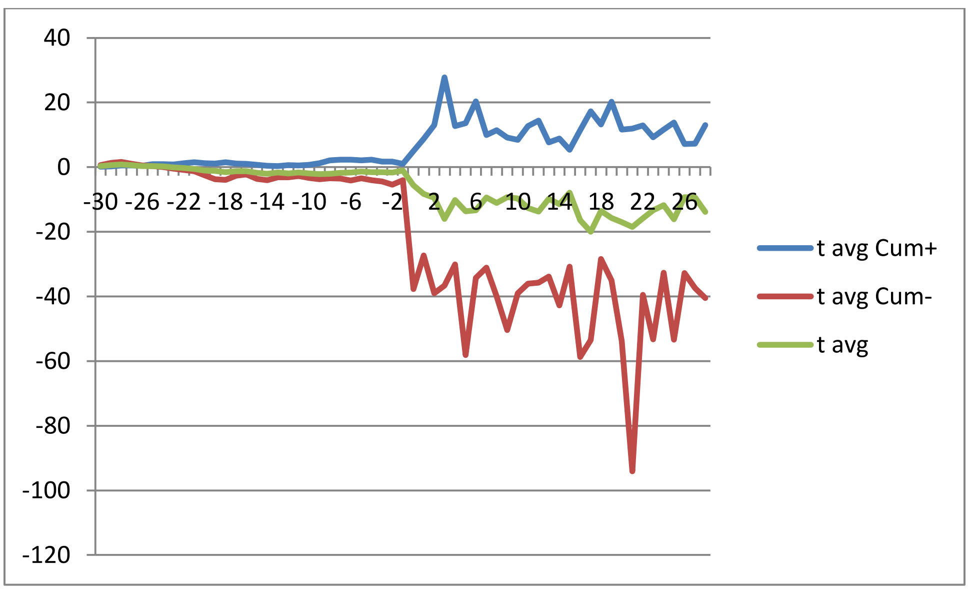


Figure 15. T-ratios of price response of the Russell 3000 stocks to the ISM Manufacturing Index announcements from January 2013 through October 2015 whenever the realized Manufacturing Index exceeded the forecast (t avg Cum+), underachieved the forecast (t avg Cum-), and all cases (t avg).

How can anyone possibly trade on the news announcements prior to the news announcements? How would one know what the news value is going to be? An intelligent forecast may certainly be one answer to this question. One set of such forecasts is compiled by Bloomberg.

How good is the consensus forecast for ISM Manufacturing Index compiled by Bloomberg? Research shows that it is not particularly good. From January 2010 to October 2015, the direction of the forecast coincided with the direction of the realized value just 32 out of 73 times. In other words, over 56 percent of time when the forecast said that the ISM Manufacturing Index was going to go up (down) the following month, the released figures actually went in the opposite direction: down (up). Since January 2013 through October 2015, that directionally-incorrect proportion of forecasts has decreased to 52 percent, with not-even-close forecasts outnumbering somewhat useful ones.

What about the forecasts for Construction Spending announcements? The latter are much better: since January 2010 through October 2015, over 71 percent of time when the forecast said that the Construction Spending was going to go up (down) the following month, the released figures actually went up (down). Since January 2013 through October 2015, that number has actually increased to 74 percent.

Aside from the directional successes and failures, both Construction and Manufacturing indexes exhibit high correlation with between differences in realized values and prior values and realized values and forecasts, as Table 1 shows. The difference between the realized construction values and their prior month values, for example, exhibits 72% correlation with the realized index value less its economic consensus forecast. Between the Construction Index and the Manufacturing Index, however, correlations are quite low, as is also shown in Table 1. As a result, the news announcements, while overlapping, leave distinct marks on prices at different times.

TABLE 1. Correlation of realized values of Construction Spending index (“Construction”) and ISM Manufacturing Index (“Manufacturing”) less prior month values and less forecasted values.

Correlation	Construction to forecast	Construction to prior	Manufacturing to forecast	Manufacturing to prior
Construction to forecast	1	0.721584	0.018799	-0.03117
Construction to prior		1	0.07238	0.017562
Manufacturing to forecast			1	0.88391
Manufacturing to prior				1

Is the consensus forecast of Construction Spending driving prices? This does not appear to be the case. Since the consensus forecast is typically released several days ahead of the announcement, the price change would have occurred at that time. Furthermore, no significant changes in prices would be observed in the ½ hour immediately preceding the news announcement. The latter is not at all the case. Figure 16 shows the average price response across all of the Russell 3000 stocks *preceding and following* a positive and negative announcement values vis-à-vis the consensus forecast values reported by Bloomberg. As Figure 16 shows, when realized Construction Spending is above the forecasted values, the average stock price across all the Russell 3000 stocks actually happens to fall ahead of the news release! On the other hand, when the announced Construction Spending figures are below the consensus forecast, the prices tend to rise ahead of the announcement. The prices stabilize immediately after the news is publically announced. Figure 17 shows the t-ratios of the averages documented in Figure 16. As Figure 17 illustrates, while the response is much more pronounced after the announcement time, the trading behavior consistent with the realized news release is prevalent as many as 20 minutes *before* the scheduled news release time. The evidence suggests that news is indeed leaked to selected traders before being made available to all.

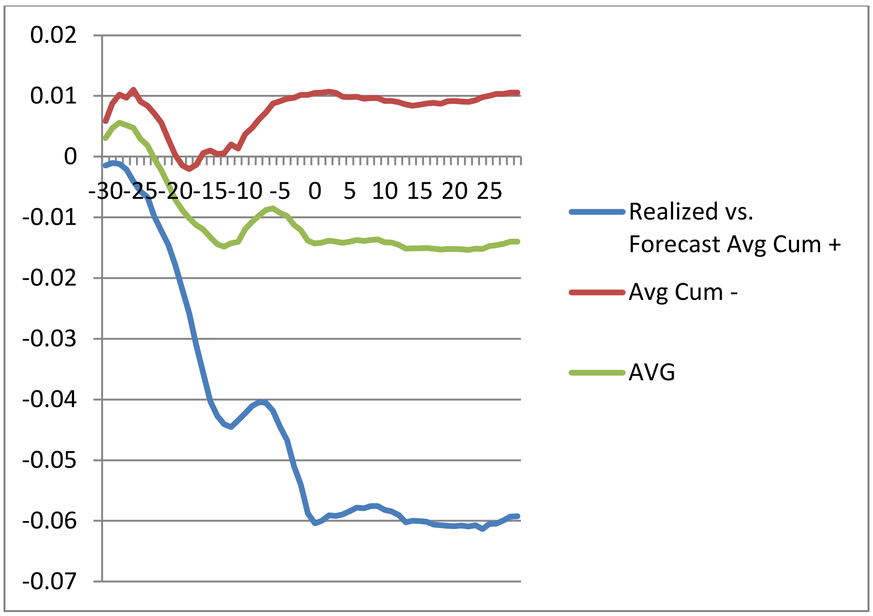


Figure 16. Cumulative Price Response of Russell 3000 stocks to the Construction Spending announcement when the realized construction spending exceeds the forecasted value (Avg Cum+), and falls short of the forecasted value (Avg Cum-).

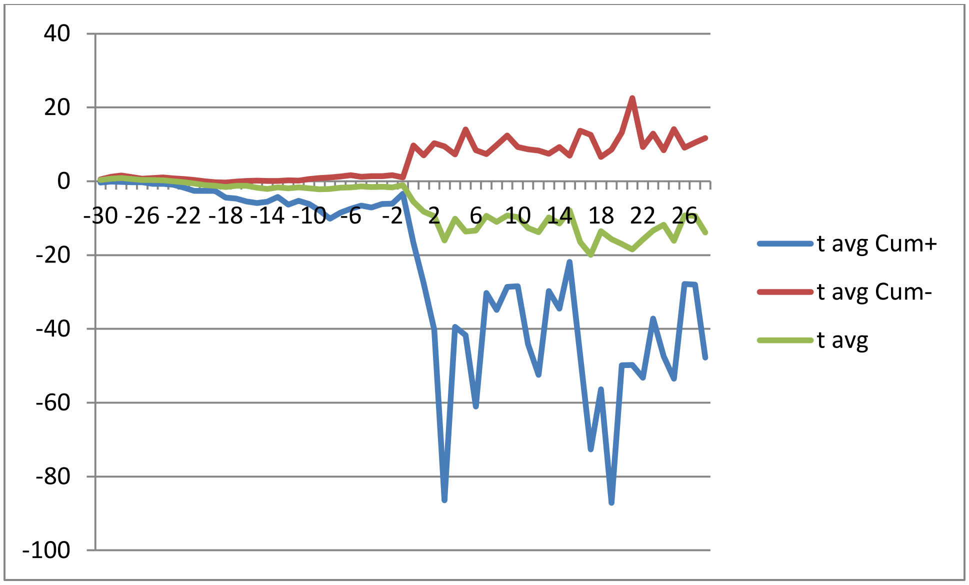


Figure 17. Statistical significance of cumulative price responses of Russell 3000 stocks measured around Construction Spending announcements when realized Construction Spending figures exceed forecasted values (t avg Cum +), fall short of the forecasted values (t avg Cum-) and all cases.

How much is this information worth? Suppose one is only trading on the ISM Manufacturing Index. As shown in Figure 10, if one were to receive the realized ISM Manufacturing Index value 30 minutes ahead of the announcement time and trade on that information, one would on average make 1.5 cents per share ($0.015) on better than last month announcements and 6.5 cent ($0.065) per share on worse than last month figures. Trading just 100 shares in each of the Russell 3000 stocks once ½ hour ahead of the news would thus produce on average in excess of $12,000 per announcement, not accounting for transaction costs. Trading the same on the Interactive Brokers, where each roundtrip trade costs $2.00, our embargoed-information trader would still clear $6,000 per announcement, trading just 100 shares ½ hour prior to the news scheduled release. Given the 1/2–hour window allowed for trading, the strategy can be easily scaled, to, say, at least 1,000 shares, easily beating a news-receiving journalist's salary in just one hour! And how many financial journalists know hedge fund managers willing to pay for this information ahead of embargo expiration?

Why is the news released on an embargoed schedule in the first place? The embargo-delay system harks back to the 1970s when the Efficient Markets Hypothesis was first developed and nothing close to today's social media existed. The only communication forms were phone and fax, and even orders could not be executed in an hour's time. In addition, the primary "near-real-time" organ of information release was radio. To ensure the widest possible distribution of the news, the news-releasing authority had to reach as many journalists and news channels as possible to level the playing field for investors to the maximum extent.

Fast forward to 2016, and the embargo system is no longer cutting it. One can trade faster than one generates a trading idea, the computers can process news data as soon as the news hits the embargoed news wires and the “level-playing-field” idea behind the original news embargo system no longer makes sense. If anything, the system allows trading on the news to the chosen few, chosen by their ability to procure the embargoed news ahead of the masses. How is this fair? Why, in today’s age of social media, can’t the news agencies release the news to all on Twitter, Dow Jones wire and other equally accessible and instantaneous channels?

Who is trading on the embargoed news? While it is hard for a bystander to point the finger at the exact trader in the anonymous markets, we can separate categories of traders active before and after the announcements. In particular, using the AbleMarkets Aggressive HFT Index, we are able to track the behavior of aggressive HFT around the news releases. Aggressive HFT is of particular interest as it has often been associated with advanced trading on news in the popular press.

Figures 18 and 19 document the behavior of aggressive HFT buyers and sellers, respectively, averaged across the Russel 3000 stocks and all ISM Manufacturing Index announcements from January 2013 through October 2015. As the figures show, behavior of aggressive HFT buyers and sellers is the same whether the realized figures are higher or lower than those of the prior month. The balanced nature of the aggressive HFT activity and higher volumes ahead of higher-than-previous announcements may explain this phenomenon. Aggressive HFTs hold positions for a very short term, and faced with the potentially high-than-normal flow ahead of positive announcements, the aggressive HFT activity goes up. In Construction Spending announcements, the separation of aggressive HFT buyers and sellers is much clearer. When the soon-to-be-released value of Construction Spending is higher (lower) than the forecast, the aggressive HFT Buyers (Sellers) are more prominent than when the realized value is lower (higher) than the forecast, as shown Figures 20 and 21. In other words, selected aggressive HFTs appear to receive and act upon advanced Construction Spending news, if not the ISM Manufacturing Index values. However, given that the cumulative price of Russell 3000 stocks moves opposite to the realized value ahead of the news release, the “in-the-know” aggressive HFTs appear to be trading to their disadvantage.

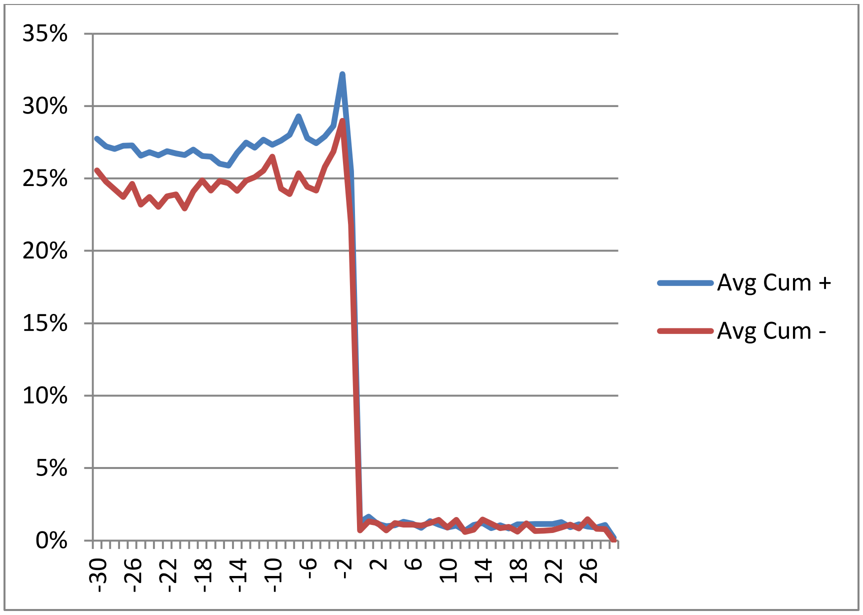


Figure 18. Behavior of aggressive HFT *buyers* around the ISM Manufacturing Index Announcements in instances when the realized news was higher (Avg Cum+) and lower (Avg Cum-) than the previous month' value.

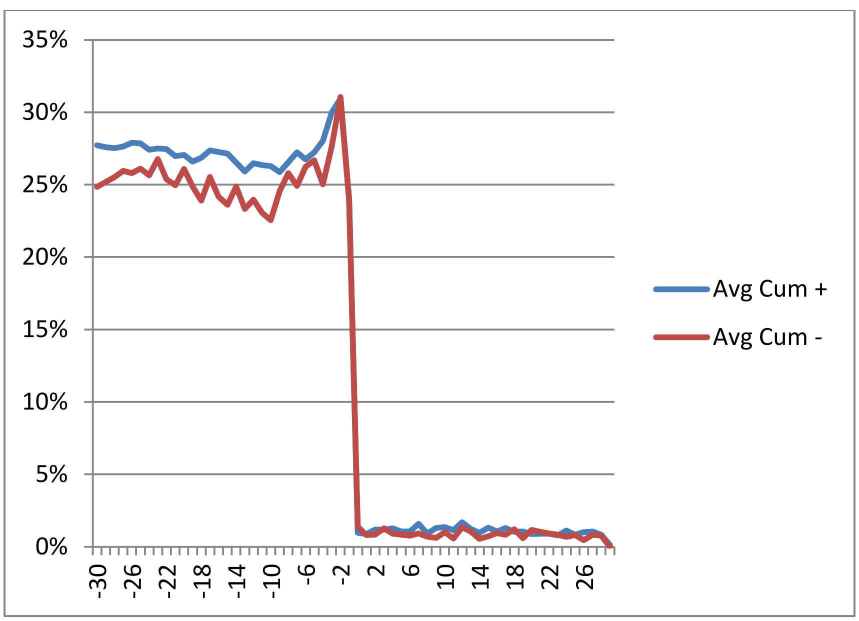


Figure 19. Behavior of aggressive HFT *sellers* around the ISM Manufacturing Index announcements in instances when the realized news was higher (Avg Cum+) and lower (Avg Cum-) than the previous month' value.

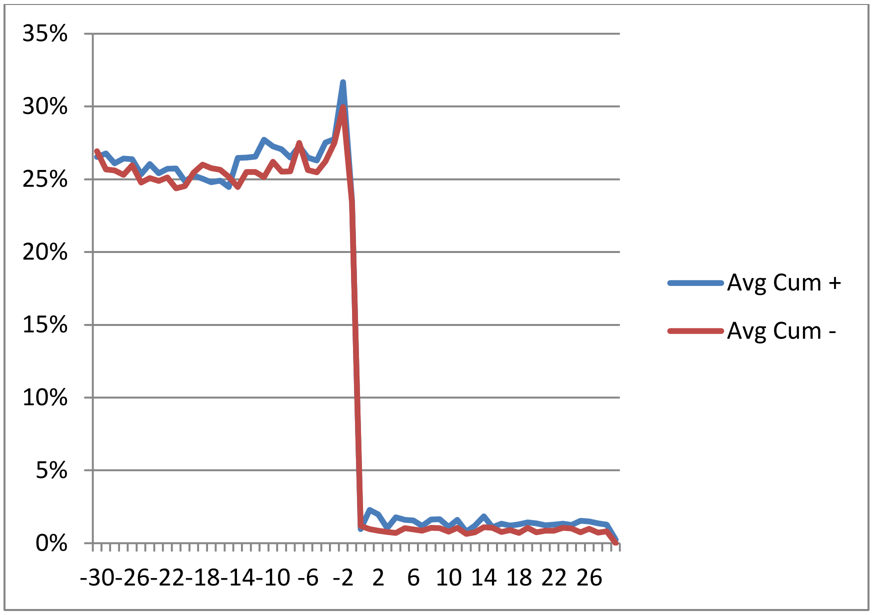


Figure 20. Participation of aggressive HFT *buyers* across Russell 3000 stocks around Construction Spending announcements when the realized value exceeds the forecast (Avg Cum +) and when the value announced at time 0 is lower than forecasted (Avg Cum-). Participation of aggressive HFT buyers as a percentage traded by volume is higher when the realized value is higher than the forecasted value.

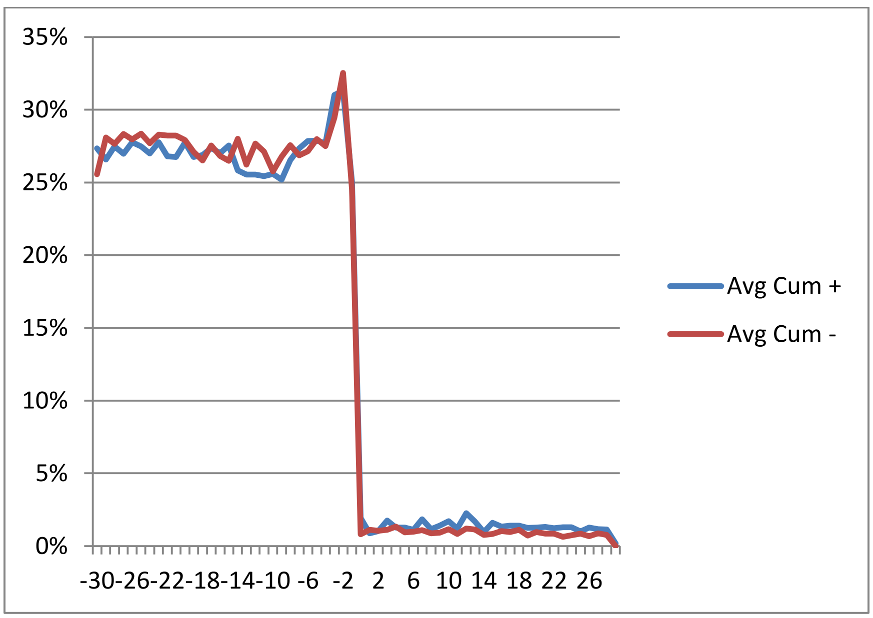


Figure 21. Participation of aggressive HFT *sellers* across Russell 3000 stocks around Construction Spending announcements when the realized value exceeds the forecast (Avg Cum +) and when the value announced at time 0 is lower than forecasted (Avg Cum-). Participation of aggressive HFT sellers as a percentage traded by volume is higher ahead of the announcement when the realized value is lower than the forecasted value.

Figure 20 shows aggressive HFT *buyer* participation around events where the realized value was higher than the forecast and lower than the forecast. As Figure 20 shows, in cases like this the aggressive HFT buyers are seen to account for a larger proportion of trading activity *after* the proper event announcement time. As seen in Figure 20, aggressive HFT accounts for about 1% more of trading activity after a higher-than-forecasted figures release than lower-than-forecasted figures release. Aggressive HFT buyers, however, account for a considerably *higher* participation before the announcement time when the announced news is higher than the forecast. This finding is consistent with the price movement ahead of news whereby the released figures are higher than the forecasted ones, shown in Figure 14. It appears that aggressive HFTs are at least partially responsible for the consistent price drop/rise ahead of news whereby the realized numbers differ from the forecast.

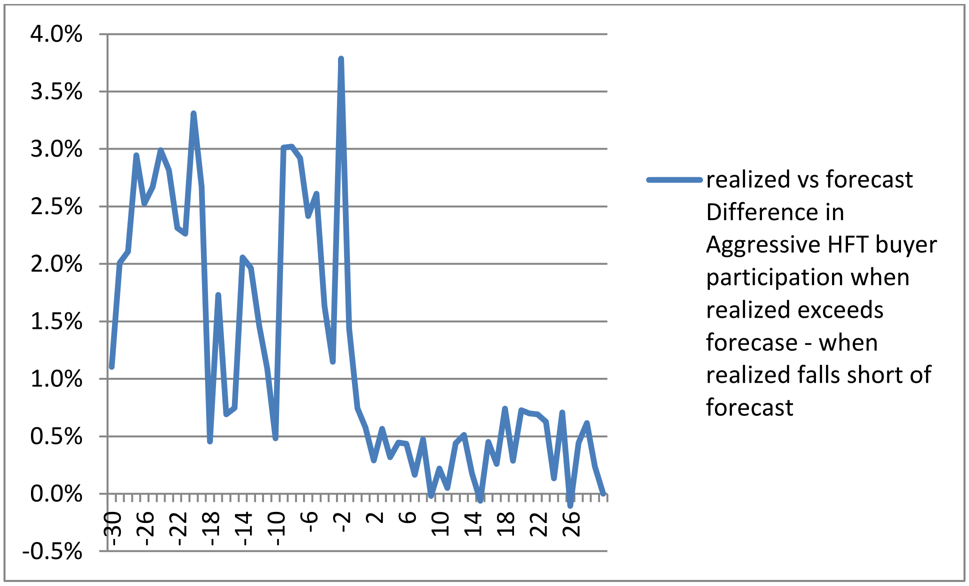


Figure 20. The difference between aggressive HFT buyer participation when the realized Construction Spending exceeds the forecast and that when the realized value falls short of the forecast.

How can this be the case? One hypothesis can be that the entities deploying aggressive HFT around the announcements prepare to maximize their profitability and volume traded on a given macro trade well ahead of the announcement. In the process, they assume that the forecast will come short of the realized value and over-accumulate stocks. Then, when the news is revealed to them, notably ahead of the announcement time, the aggressive HFT strategies sell off excess inventory to align their holdings with the expected post-announcement price, now easily quantifiable under the rational expectations hypothesis. The resulting strategy benefits the participating entities in two ways: a) maximizes traded capital, and b) helps avoid detection as the direction of pre-announcement trading is reversed vis-à-vis the expected price direction given the announcement.

What are the implications of the aggressive HFT activity for market-makers? Aggressive HFT flow is toxic and is best avoided from the market-making perspective. As a result, market-makers may significantly improve their profitability around news announcements by explicitly tracking aggressive HFT behavior.

The aggressive HFTs, however, are not the only entities receiving advanced news data. The price movement ahead of Construction Spending announcements is most pronounced in the difference between the realized and prior values, as shown in Figure 10. Participation of aggressive HFTs, however, cannot be differentiated between positive and negative news announcement values in that setting, implying that non-HFT entities are trading on the leaked news ahead of the news announcements. Furthermore, those non-HFT entities appear to completely disregard the forecasts, going against all modern sophisticated theories, such as the Rational Expectations. It is further likely that those entities are not particularly sophisticated, since Bloomberg consensus forecasts do predict correct directionality to the news at least 70 percent of the time – a considerable improvement on the coin flip. Then again, who needs forecasts when you can recieve the actual values ½ hour ahead of everyone else?

Detailed Analysis

To formally study the price action around news announcements, we apply the event study methodology to the price changes of the stocks comprising the Russell 3000. We then include other factors traditionally thought to affect prices as control variables. The analysis allows us to distill responses to macro announcements across various categories of stocks comprising the Russell 3000 index: large-cap and medium-cap, growth and value, different industries.

The event data, comprising of the event date, time, name , consensus and realized values, is from Bloomberg. Appendix contains the list of the events. The tick data, used to measure the intraday price changes surrounding the news announcements, is from BATS. The price changes are computed as percentage changes of the realized price (last price) vis-à-vis the trade price a specified number of minutes prior. The last trade value include trades initiated by market orders and marketable limit orders and executed against resting limit orders as well as hidden (iceberg) orders.

In our analysis, we seek to determine the very short-term impact of the news content on the returns of the entire Russell 3000 index. Given the short-term nature of our study, we can assume that the returns are normally distributed, allowing us to deploy Ordinary Least Squares (OLS) methodology for estimation. And while Huber (1973) and Yohai (1987) show that OLS is sensitive to the outliers, the breadth of our observations, namely the entire Russell 3000 set of equities, considerably dampen the problem of outliers. In addition, studies like Starks (1994) and Mucklow (1994) have shown that OLS studies on intraday data allow for more precise and meaningful inferences than the daily studies.

Our study is the first to our knowledge to document the leakage of news into the markets *ahead* of the news announcements. Studies like Andersen and Bollerslev (1998), Andersen, Bollerslev, Diebold and

Vega (2007), Hotchkiss and Ronen (2002) and Busse and Greene (2002) document the impact of announcement on the intraday data, but after the event, and not before the news release.

Our null hypothesis is that news events do not move the markets, particularly ahead of the announcements, as one would expect if the news embargoes were observed. The alternative hypothesis is that trading indeed occurs ahead of the announcement. Following Sorokina, Booth and Thornton (2013) and Mamun, Hassan and Lai (2004), we estimate the news announcement impact on prices using the model shown in equation (1). Due to the high correlation of realized-to-forecasted and realized-to-prior values of indexes shown in Table 1, and since the forecasted values are expected to be priced in at the time of the event study following the rational expectations theory, we study the impact of the news events relative to their forecasted values only. The model (1) estimates the changes in return, α, at the news release time:

$$R_{i,j} = \alpha_i + \alpha'_i D' + \theta_i M_j + \theta'_i D' M_j + \gamma_i C_j + \gamma'_i D' C_j + \varepsilon_{i,j} \quad (1)$$

where:

$R_{i,j}$ is the return on the ith security comprising the Russell 3000 index before or after the announcement on day *j*

α_i is the average stock return during the event announcement window (+/- 30 minutes from 10 AM on the day of each announcement)

α'_i is the average difference in the stock return before and after the news was announced

D' is the dummy indicator of whether the given return belongs to the before or after the news announcement period (0 = before, 1 = after)

θ_i is the impact of the ISM Manufacturing index on returns

M_j is the realized-to-forecasted change in the ISM Manufacturing index on date *j*

θ'_i is the difference in the stock returns due to the ISM Manufacturing index announcement before and after the news announcement

γ_i is the impact of the Construction Spending index on returns of stock *i*

C_j is the realized-to-forecasted change in the construction spending index on day *j*

γ'_i is the difference in the ith stock returns due to the Construction Spending index announcement before and after the news announcement

Table 2 presents the results of the OLS regression in equation (1) for the entire Russell 3000 index, Apple (AAPL) and Stanley Black & Decker (SWK). The Apple stock and that of Black and Decker were randomly selected as examples of commonly held (AAPL) and less commonly held (SWK) to showcase the impact of the news announcements on individual stocks. As Table 2 shows, the results are consistent with the visualizations of Figures 10-20. Specifically, across all the Russell 3000 stocks, the ISM Manufacturing Index and the Construction Spending announcements are incorporated into prices prior to the news announcement, as evident by the statistical significance of γ_i and θ_i relative to the post-news change coefficients, γ'_i and θ'_i. An increase in the manufacturing index results in an increase of Russell 3000 prices 99.99% of time from 9:30 AM to 10:00 AM on the days of the index announcements. However, not all of the stocks respond to the announcements in the uniform fashion. For example, the price of AAPL changes with the rest of the Russell 3000 in response to the ISM Manufacturing index, but barely registers the Construction Spending news announcements, while the price of SWK moves along with the Russell 3000.

As Table 2 shows, in response to the news announcements, the post-announcement change in the price of the stocks is far less significant than the price movement from 9:30 AM to 10:00 AM. In other words, most of the news is incorporated into prices of the Russell 3000 index ahead of the news announcement. Given the "gentleman's agreement" nature of the news embargo, the pre-announcement trading on the news is technically legal. The fairness of the arrangement, however, is potentially something begging for a discussion.

TABLE 2. Estimation of the ISM Manufacturing Index and Construction Spending Index announcements' impact on returns of the Russell 3000 stocks during the 30 minutes preceding and the 30 minutes following the announcement.

	Entire Russell 3000	**AAPL**	**SWK**
$\boldsymbol{\alpha}$	**-0.02133 (-8.15)**	-1.17124 (-1.728)	-0.04835 (-0.425)
$\boldsymbol{\alpha'}$	**0.028385 (7.67)**	0.393285 (0.410)	0.026597 (0.165)
$\boldsymbol{\gamma}$	**0.017439 (9.91)**	0.233161 (0.517)	0.119142 (1.577)
$\boldsymbol{\gamma'}$	-0.00134 (0.54)	-0.20769 (-0.326)	-0.10047 (-0.940)
$\boldsymbol{\theta}$	**-0.02024 (-8.15)**	0.29832 (0.466)	-0.12505 (-1.167)
$\boldsymbol{\theta'}$	**0.016758 (4.77)**	-0.31334 (-0.346)	0.116229 (0.767)
$\boldsymbol{Adj.R^2}$	0.2%	-9.3%	-2.1%

Who is trading on the news announcements? Some investment managers have proposed that high-frequency traders are squarely responsible for the news leakage and the apparent "front-running" of the general investing public. The logic behind the idea that only high-frequency traders were capable of taking advantage of the news was based largely on the fact that no prior study has ever documented the extent and significance of pre-announcement trading. Indeed, if the news were leaked out some 20 milliseconds ahead of the announcement because a high-frequency trader happened to have a faster connection to Reuters than his regular-antennaed brethren, then of course the HFT's nano-second execution speed would be helpful in taking advantage of the news disparity. However, when the news is legally obtained by the selected few at least ½ hour ahead of the announcement, who cares about speedy execution? In today's world, with that much lead time, one can even phone in his buy or sell orders from a yacht in the middle of nowhere.

To ascertain who is behind the price movement prior to the news announcement, we analyze the behavior of aggressive high-frequency traders, computed and distributed by AbleMarkets (AbleMarkets.com). The AbleMarkets Aggressive HFT index covers the Russell 3000 stocks and estimates the participation of aggressive HFT in every stock's flow as a percentage of volume separated by buyer-initiated and seller-initiated trades. The aggressive HFT, as opposed to passive HFT, tend to use market orders in a bid to take advantage of rapidly-decaying information. Passive HFT, on the other hand, comprise market-makers and other "patient" strategies where the trade horizon is not immediate. Unlike the passive HFT, aggressive HFT cannot afford to take the chances on the time and the uncertainty of execution embedded in trading using limit orders, also known as passive orders.

To examine the interaction of aggressive HFT and construction and manufacturing news, we deploy the model of equation (2):

$$R_{i,j} = \alpha_i + \alpha'_i D' + \nu_i AHFT_{ij,Buy} + \nu'_i D' AHFT_{ij,Buy} + \xi_i AHFT_{ij,Sell} + \xi'_i D' AHFT_{ij,Sell} + \theta_i M_j + \theta'_i D' M_j + \gamma_i C_j + \gamma'_i D' C_j + \varepsilon_{i,j} \qquad (2)$$

where

$R_{i,j}$ is the return on the ith security comprising the Russell 3000 index before or after the announcement on day *j*

α_i is the average stock return during the event announcement window (+/- 30 minutes from 10 AM on the day of each announcement)

α'_i is the average difference in the stock return before and after the news was announced

D' is the dummy indicator of whether the given return belongs to the before or after the news announcement period (0 = before, 1 = after)

ν_i is the impact of aggressive HFT buyers on returns

$AHFT_{ij,Buy}$ is the 30-minute average of the AbleMarkets aggressive HFT index measuring the proportion of aggressive HFT buyers by volume traded, valued 0-100. The index is measured before and after the news announcement (9:30 AM to 10:00 AM and, separately, 10:00 AM to 10:30 AM).

ν'_i is the difference in the stock return changes due to aggressive HFT buyers before and after the announcement

ξ_i is the impact of aggressive HFT sellers on returns

$AHFT_{ij,Sell}$ is the 30-minute average of the AbleMarkets aggressive HFT index measuring the proportion of aggressive HFT sellers in stock *i* by volume traded, valued 0-100. The index is measured before and after the news announcement (9:30 AM to 10:00 AM and, separately, 10:00 AM to 10:30 AM) on the announcement day *j*

  irene@ablemarkets.com - 2/5/2016

ξ'_i is the difference in the stock return changes due to aggressive HFT sellers before and after the announcement

θ_i is the impact of the ISM Manufacturing index on returns

M_j is the realized-to-forecasted change in the ISM Manufacturing index on date *j*

θ'_i is the difference in the stock returns due to the ISM Manufacturing index announcement before and after the news announcement

γ_i is the impact of the Construction Spending index on returns of stock *i*

C_j is the realized-to-forecasted change in the construction spending index on day *j*

γ'_i is the difference in the ith stock returns due to the Construction Spending index announcement before and after the news announcement

TABLE 3. Estimation of pre- and post-announcement price changes of Russell 3000 as a function of the news content and aggressive HFT behavior, following the model of equation (3) during the 30 minutes preceding and the 30 minutes following the announcement.

	Russell 3000	AAPL	SWK
$\boldsymbol{\alpha}$	-0.00249 (-0.594)	0.257946 (0.046)	1.071755 (0.636)
$\boldsymbol{\alpha'}$	-0.01099 (-1.910)	-0.14843 (-0.023)	-1.44995 (-0.809)
$\boldsymbol{\nu}$	**0.005384 (124.597)**	0.020427 (1.933)	0.003567 (1.010)
$\boldsymbol{\nu'}$	**-0.00308 (-67.968)**	-0.01402 (-1.316)	-0.001131 (-0.315)
$\boldsymbol{\xi}$	**-0.00539 (-125.04)**	-0.02168 (-2.624)	-0.00732 (-2.049)
$\boldsymbol{\xi'}$	**0.003108 (68.629)**	0.015152 (1.813)	0.005015 (1.387)
$\boldsymbol{\gamma}$	0.003272 (2.127)	0.234974 (0.746)	0.058254 (0.879)
$\boldsymbol{\gamma'}$	**0.009849 (4.532)**	-0.24277 (-0.545)	-0.07356 (-0.814)
$\boldsymbol{\theta}$	**-0.00657 (-3.029)**	0.657118 (1.353)	-0.02007 (-0.210)
$\boldsymbol{\theta'}$	0.00366 (1.194)	-0.87425 (-1.289)	0.022278 (0.170)
$\boldsymbol{Adj.R^2}$	24.3%	47.2%	33.5%

As results of the estimation of equation (2) presented in Table 3 show, the aggressive HFT accounts for a significant price movement both before and after the news announcement. A prevalence of aggressive HFT buyers, as measured by AbleMarkets aggressive HFT index, results in higher Russell 3000 returns, as evidenced by the coefficients ν, ν', ξ and ξ'. An increase in aggressive HFT sellers drives the stock prices down.

The significance of returns as a function of the news content decreases when the aggressive HFT metrics are included in the model. Comparing the results in Table 3 with those in Table 2, we observe that the prices before the positive ISM Manufacturing index still rise with aggressive HFT in the model, but with lower statistical significance than when aggressive HFT are not included in the model. As shown by the coefficient γ, when the aggressive HFTs are not accounted for, the price rise following the announcement increases by 1.7% for every point increase in the ISM Manufacturing index. In contrast, accounting for the aggressive HFT participation, brings γ down to 0.32% of average price increase for every 1 point rise in the ISM Manufacturing Index. This implies that as much as 1.38% increase in the average price of the Russell 3000 index is due to the aggressive HFTs trading on the embargoed news ahead of the ISM Manufacturing Index announcement. As θ coefficient difference between Tables 2 and 3 demonstrates, the aggressive HFTs appear to be responsible for 1.4% of price change per every 1 point change in Construction Spending ahead of the Construction Spending Index announcement. Interestingly, the post-announcement impact of the ISM Manufacturing index, slightly negative when the aggressive HFT is excluded, becomes positive and highly significant when the impact of aggressive HFT is abstracted, suggesting that 1) many non-HFT market participants trade on the ISM Manufacturing news after the news announcement, and 2) it is mostly non-HFT market participants that are responsible for directional price changes following news announcements.

Conclusions

Macroeconomic news is leaked out to the markets at least ½ hour ahead of the scheduled public news release time. This outcome is likely a result of the way much of the macroeconomic news has been distributed for the past half century. Journalists and other selected parties are given an-hour-ahead news releases with the hope that the stories they write in one hour will promote the news to the largest distribution possible. The embargo process is strictly honor-based. Coupled with the supersonic speed of trading today, the advanced news recipients have all the incentives to either trade upon or even sell the advanced news to other trading parties. A reconsideration of the news embargo system may be a sound action on behalf of agencies charged with protecting modern markets, such as the U.S. Securities and Exchange Commission (SEC), the Commodity Futures Trading Commission (CFTC) and the U.K. Financial Services Authority (FSA).

Surprisingly, many market participants ignore economic forecasts regarding upcoming events. Aside from those receiving the news ahead of time (really, who needs economic forecasts in this case!), the post-event price of Russell 3000 stocks moves more in tandem with the realized values relative to the prior month's values rather than relative to the forecasted values, despite the forecasts' considerable directional correctness.

What should investors do to minimize the impact of the news on their portfolios without the same access to the preferentially-distributed embargoed information to? Tracking aggressive HFT may help make informed portfolio and market-making decisions when trading around macroeconomic news.

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Biased forecasts or biased earnings? The role of reported earnings in explaining apparent bias and over/underreaction in analysts' earnings forecasts ☆

Jeffery Abarbanell[a], Reuven Lehavy[b,*]

[a] Kenan-Flagler Business School, University of North Carolina at Chapel Hill, Chapel Hill, NC 27599-3490, USA
[b] University of Michigan Business School, 701 Tappan Street, Ann Arbor, MI 48109-1234, USA

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Abstract

The extensive literature that investigates whether analysts' earnings forecasts are biased and/or inefficient has produced conflicting evidence and no definitive answers to either question. This paper shows how two relatively small but statistically influential asymmetries in the tail and the middle of distributions of analysts' forecast errors can exaggerate or obscure evidence consistent with analyst bias and inefficiency, leading to inconsistent inferences. We identify an empirical link between firms' recognition of unexpected accruals and the presence of the two asymmetries in distributions of forecast errors that suggests that firm reporting choices play an important role in determining analysts' forecast errors.

JEL classification: G10; G14; M41

Keywords: Analysts' forecasts; Earnings management; Bias; Inefficiency

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*Corresponding author. Tel.: +1-734-763-1508; fax: +1-734-936-0282.
E-mail address: rlehavy@umich.edu (R. Lehavy).

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1. Introduction

Four decades of research have produced an array of empirical evidence and a set of behavioral and incentive-based theories that address two fundamental questions: Are analysts' forecasts biased? And Do analysts underreact or overreact to information in prior realizations of economic variables? This empirical literature has long offered conflicting conclusions and is not converging to a definitive answer to either question. On the one hand, theories that predict optimism in forecasts are consistent with the persistent statistical finding in the literature of cross-sectional negative (i.e., bad news) mean forecast errors as well as negative intercepts from regressions of forecasts on reported earnings. On the other hand, such theories are inconsistent both with the finding that median forecast errors are most often zero and with the fact that the percentage of apparently pessimistic errors is greater than the percentage of apparently optimistic errors in the cross-section. A similar inconsistency is found in the literature on analyst over/underreaction to prior realizations of economic variables, including prior stock returns, prior earnings changes, and prior analyst forecast errors. Here, again, empirical evidence supports conflicting conclusions that analysts overreact to prior news, underreact to prior news, and both underreact and overreact as a function of the sign of prior economic news. Further reflecting the lack of consensus in the literature, a handful of studies fail to reject unbiasedness and efficiency in analyst forecasts after "correcting" methodological flaws or assuming nonstandard analyst loss functions.[1]

The accumulation of often inconsistent results concerning analyst rationality and incentives makes it difficult for researchers, practitioners, and policy makers to understand what this literature tells us. This motivates us to reexamine the body of evidence with the goal of identifying the extent to which particular theories for apparent errors in analysts' forecasts are supported by the data. Such an exercise is both appropriate and necessary at this juncture as it can, among other things, lead to modified theories that will be tested using the new and unique hypotheses they generate.

We extend our analysis beyond a synthesis and summary of the findings in the literature by identifying the role of two relatively small asymmetries in the cross-sectional distributions of analysts' forecast errors in generating conflicting statistical evidence. We note that the majority of conclusions concerning analyst-forecast rationality in the literature are directly or indirectly drawn from analyses of these distributions. The first asymmetry is a larger number and a greater magnitude of observations that fall in the extreme negative relative to the extreme positive tail of the forecast error distributions (hereafter, the *tail asymmetry*). The second asymmetry is a higher incidence of small positive relative to small negative forecast errors in cross-sectional distributions (hereafter, *the middle asymmetry*). The individual and combined impact of these asymmetries on statistical tests leads to three important observations. First, differences in the manner in which researchers

[1] A representative selection of evidence and theory relevant to both the bias and over/underreaction literatures is discussed in the body of the paper.

implicitly or explicitly weight observations that fall into these asymmetries contribute to inconsistent conclusions concerning analyst bias and inefficiency. Second, a variety of econometric techniques and data adjustments fail to eliminate inconsistencies in inferences across different statistical indicators and conditioning variables. Such techniques include using indicator variables or data partitions in parametric tests, applying nonparametric methods, and performing data truncations and transformations. Third, econometric approaches that choose loss functions that yield consistent inferences—essentially by attenuating the statistical impact of observations that comprise the asymmetries—will not provide definitive answers to the question of whether analysts' forecasts are biased and inefficient. This is because at this stage in the literature too little is known about analysts' actual loss functions, and such methods thus leave unresolved the question of why the asymmetries in forecast error distributions are present.

We present statistical evidence that demonstrates how the two asymmetries in forecast error distributions can indicate analyst optimism, pessimism, or unbiasedness. We also show how observations that comprise the asymmetries can contribute to, as well as obscure, a finding of apparent analyst inefficiency with respect to prior news variables, including prior returns, prior earnings changes, and prior forecast errors. For example, our empirical evidence explains why prior research that relies on parametric statistics always finds evidence of optimistic bias as well as apparent analyst underreaction to prior bad news for all alternative variables chosen to represent prior news. It also explains why evidence of apparent misreaction to good news is *not* robust across parametric statistics or across prior news variables, and why the degree of misreaction to prior bad news is always greater than the degree of misreaction to prior good news, regardless of the statistical approach adopted or the prior information variable examined.

Finally, while our analysis does not lead to an immediately obvious solution to problems of inferences in the literature, it does reveal a link between the reported earnings typically employed to benchmark forecasts and the presence of the two asymmetries in distributions of forecast errors. Specifically, we find that extreme negative unexpected accruals included in reported earnings go hand in hand with observations in the cross-section that generate the tail asymmetry. We also find that the middle asymmetry in distributions of forecast error is eliminated when the reported earnings component of the earnings surprise is stripped of unexpected accruals. This evidence suggests benefits to refining extant cognitive- and incentive-based theories of analyst forecast bias and inefficiency so that they can account for an endogenous relation between forecast errors and manipulation of earnings reports by firms. The evidence also highlights the importance of future research into the question of whether reported earnings are, in fact, the correct benchmark for assessing analyst bias and inefficiency. This is because common motivations for manipulating earnings can give rise to the appearance of analyst forecast errors of exactly the type that comprise the two asymmetries if unbiased and efficient forecasts are benchmarked against manipulated earnings. Thus, it is possible that some evidence previously deemed to reflect the impact of analysts' incentives and cognitive tendencies on forecasts is, after all, attributable to the fact that analysts do not have the motivation or ability to completely anticipate earnings management by firms in their forecasts.

This paper's emphasis is on fleshing out salient characteristics of forecast error distributions with an eye toward ultimately explaining how they arise. The analysis highlights the importance of new research that explains the actual properties of forecast error data and cautions against the application of econometric fixes that either fit the data to specific empirical models or fit specific empirical models to the data without strong a priori grounds for doing so. Our findings also represent a step toward understanding what analysts really aim for when they forecast, which is useful for developing more appropriate null hypotheses in tests of analysts' forecast rationality, and sounder statistical test specifications, as well as the identification of first-order effects that may require control when testing hypotheses that predict analyst forecast errors.

In the next section we describe our data and present evidence of the sensitivity of statistical inferences concerning analyst optimism and pessimism to relatively small numbers of observations that comprise the tail and middle asymmetries. Section 3 extends the analysis to demonstrate the impact of the two forecast error asymmetries on inferences concerning analyst over/underreaction conditional on prior realizations of stock returns and earnings changes, as well as on serial correlation in consecutive-quarter forecast errors. Section 4 presents evidence of a link between biases in reported earnings and the two asymmetries and discusses possible explanations for this link as well as the implications for interpreting evidence from the literature and for the conduct of future research. A summary and conclusions are provided in Section 5.

2. Properties of typical distributions of analysts' forecast errors and inferences concerning analysts' optimism, pessimism, and unbiasedness

2.1. Data

The empirical evidence in this paper is drawn from a large database of consensus quarterly earnings forecasts provided by Zacks Investment Research. The Zacks earnings forecast database contains approximately 180,000 consensus quarterly forecasts for the period 1985–1998. For each firm quarter we calculate forecast errors as the actual earnings per share (as reported in Zacks) minus the consensus earnings forecast outstanding prior to announcement of quarterly earnings, scaled by the stock price at the beginning of the quarter and multiplied by 100. Our results are insensitive to alternative definitions of forecasts such as the last available forecast or average of the last three forecasts issued prior to quarter-end. Inspection of the data revealed a handful of observations that upon further review indicated data errors. These observations had no impact on the basic features of cross-sectional distributions of errors that we describe, but they were nevertheless removed before carrying out the statistical tests reported in this paper. Empirical results obtained after removing these observations were virtually identical to those obtained when the distributions of quarterly forecast errors were winsorized at the 1st and 99th percentiles, a common practice for mitigating the possible effects of data errors followed in the literature. (To enhance comparability with the majority of studies cited below, all test results reported in the paper are based on the winsorized data.)

Lack of available price data reduced the sample size to 123,822 quarterly forecast errors. The data requirements for estimating quarterly accruals further reduced the sample on which our tabled results are based to 33,548 observations.[2] For the sake of brevity we present only results for this reduced sample. We stress, however, that the middle and tail symmetries we document below are present in the full sample of forecast errors and that the proportion of observations that comprise these asymmetries is roughly the same as that for the reduced sample. Moreover, the descriptive evidence and statistical findings relevant to apparent bias and inefficiency in analyst forecasts presented in this section and the next are qualitatively similar when we do not impose the requirement that data be available to calculate unexpected accruals.[3]

2.2. *The impact of asymmetries in the distribution of forecast errors on inferences concerning bias*

One of the most widely held beliefs among accounting and finance academics is that incentives and/or cognitive biases induce analysts to produce generally optimistic forecasts (see, e.g., reviews by Brown (1993) and Kothari, 2001). This view is repeatedly reinforced when studies that employ analysts' forecasts as a measure of expected earnings present descriptive statistics and refer casually to negative mean forecast errors as evidence of the purportedly "well-documented" phenomenon of optimism in analyst forecasts.[4] The belief is even more common among regulators (see, e.g., Becker, 2001) and the business press (see, e.g., Taylor, 2002). In spite of the prevalent view of analyst forecast optimism, summary statistics associated with forecast error distributions reported in Panel A of Table 1 raise doubts about this conclusion.

[2] As described in Section 4, we use a quarterly version of the modified Jones model to estimate accruals. For the purposes of sensitivity tests, we also examine a measure of unexpected accruals that excludes nonrecurring and special items (see, Hribar and Collins, 2002), and use this adjusted measure in conjunction with *Zacks*' consensus forecast estimates and actual reported earnings, which also exclude such items. All the results involving unexpected accruals reported in the paper are qualitatively unaltered using this alternative measure.

[3] The results are also qualitatively similar when data from alternative forecast providers (I/B/E/S and First Call) are employed, indicating that the findings we revisit in this study are not idiosyncratic to a particular data source (see, Abarbanell and Lehavy, 2002).

[4] The perception is also strengthened in a number of studies that place analyst forecasts and reported earnings numbers (i.e., the two elements that comprise the forecast error) on opposite sides of a regression equation. These studies uniformly find significant intercepts and either casually refer to them as consistent with analyst optimism or emphasize them in supporting their prediction of analyst bias. Evidence presented below, however, indicates a nonlinear relation between forecasts and earnings, which contributes to nonzero intercepts in OLS regressions.

Table 1
Descriptive statistics on quarterly distributions of forecast errors (Panel A), the tail asymmetry (Panel B), and the middle asymmetry (Panel C), 1985–1998

Panel A: Statistics on forecast error distributions	
Number of observations	33,548
Mean	−0.126
Median	0.000
% Positive	48%
% Negative	40%
% Zero	12%
Panel B: Statistics on the "tail asymmetry" in forecast error distributions	
P5	−1.333
P10	−0.653
P25	−0.149
P75	0.137
P90	0.393
P95	0.684

Panel C: Statistics on the "middle asymmetry" in forecast error distributions

Range of forecast errors (1)	Ratio of positive to negative forecast errors (2)	% of total number of observations (3)
Overall	1.19	100
Forecast errors = 0		12
[−0.1, 0) & (0, 0.1]	1.63*	29
[−0.2, −0.1) & (0.1, 0.2]	1.54*	18
[−0.3, −0.2) & (0.2, 0.3]	1.31*	10
[−0.4, −0.3) & (0.3, 0.4]	1.22*	7
[−0.5, −0.4) & (0.4, 0.5]	1.00	5
[−1, −0.5) & (0.5, 1]	0.83*	11
[Min, −1) & (1, Max]	0.40*	9

This table provides descriptive statistics on quarterly distributions of forecast errors for the period of 1985–1998. Analyst earnings forecasts and actual realized earnings are provided by *Zacks Investment Research*. Panel A provides the mean, median, and frequencies of quarterly forecast errors. Panel B provides percentile values of forecast error distributions. Panel C reports the ratio of positive to negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors. For example, the forecast error range of [−0.1, 0) & (0, 0.1] includes all observations that are greater than or equal to −0.1 and (strictly) less than zero and observations that are greater than zero and less than or equal to 0.1. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price.

* A test of the difference in the frequency of positive to negative forecast errors is statistically significant at or below a 1% level.

As can be seen in Panel A, the only statistical indication that supports the argument for analyst optimism is a fairly large negative mean forecast error of −0.126. In contrast, the median error is zero, suggesting unbiased forecasts, while the percentage of positive errors is significantly greater than the percentage of negative errors (48% vs. 40%), suggesting apparent analyst pessimism.

To better understand the causes of this inconsistency in the evidence of analyst biases among the summary statistics, we take a closer look at the distribution of forecast errors. Panel A of Fig. 1 presents a plot of the 1st through the 100th percentiles of the pooled quarterly distributions of forecast errors over the sample period. Moving from left to right, forecast errors range from the most negative to the most positive.

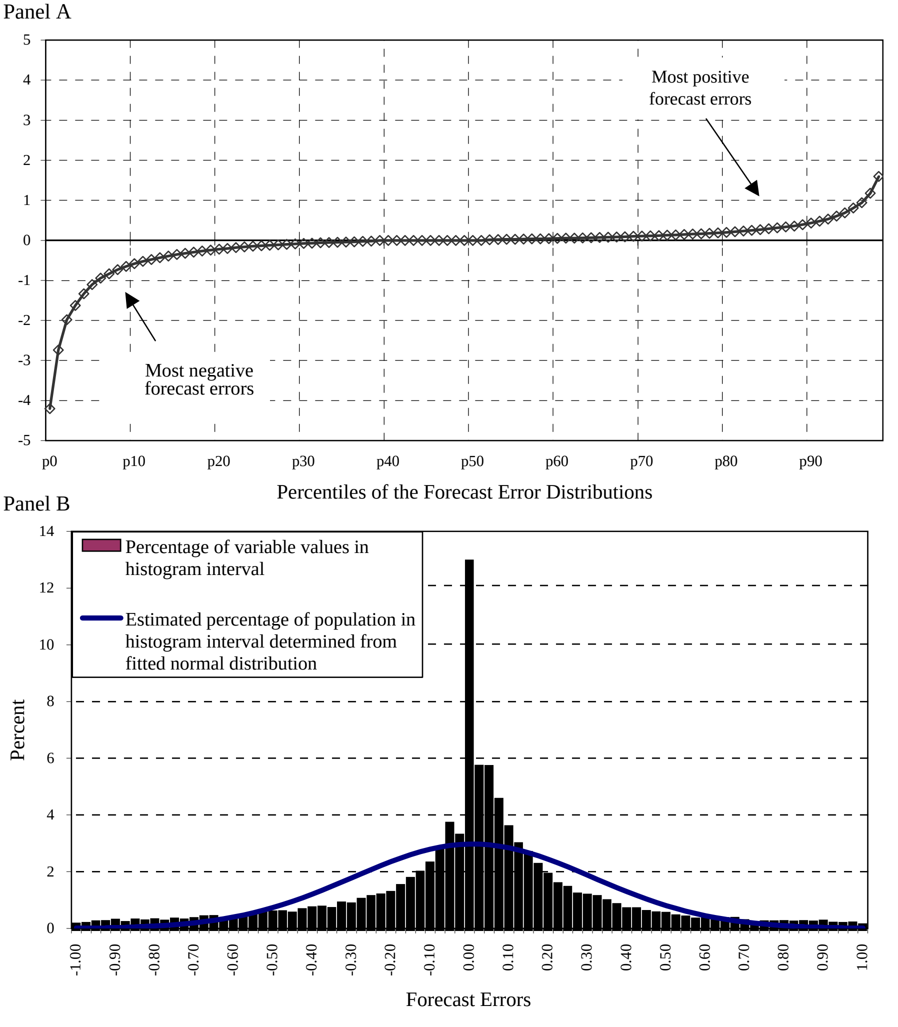

Fig. 1. Percentile values of quarterly distributions of analyst forecast errors (Panel A) and histogram of forecast errors for observations within forecast errors of -1 to $+1$ (Panel B). Panel A depicts percentile values of quarterly distributions of analyst forecast errors. Panel B presents percentage of forecast error values in histogram intervals for observations within a forecast error of -1% to $+1\%$ of the beginning-of-period stock price. Forecast error equals reported earnings minus the consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price ($N = 33,548$).

One distinctive feature of the distribution is that the left tail (ex-post bad news) is longer and fatter than the right tail, i.e., far more extreme forecast errors of greater absolute magnitude are observed in the ex-post "optimistic" tail of the distribution than in the "pessimistic" tail. We refer to this characteristic of the distribution as the *tail asymmetry*. Although Fig. 1 summarizes the distribution of observations over the entire sample period, unreported results indicate that a tail asymmetry is present in each quarter represented in the sample. To get a sense of the magnitude of the asymmetry, we return to Panel B of Table 1, where the 5th percentile (extreme negative forecast errors) is nearly twice the size observed for the 95th percentile (-1.333 vs. 0.684). Alternatively, we find that 13% of the observations fall below a negative forecast error of -0.5, while only 7% fall above a positive error of an equal magnitude (not reported in the table).

Closer visual inspection of the data reveals a second feature of the distribution depicted in Panel B of Fig. 1—a higher frequency of small positive forecast errors versus small negative errors. Specifically, the figure presents the frequencies of forecast errors that fall in fixed subintervals of 0.025 within the range of -1 to $+1$. Clearly, the *incidence* of small positive relative to small negative errors increases as forecast errors become smaller in absolute magnitude. We refer to this property of the distribution as the *middle asymmetry*.[5] Statistics on the magnitude of the middle asymmetry are reported in Panel C of Table 1. This panel presents the ratio of positive (i.e., apparently pessimistic) errors to negative errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors. Consistent with the visual evidence in Panel B of Fig. 1, this ratio increases for smaller, symmetric intervals of forecast errors, reaching 1.63 in the smallest interval examined (significantly different from 1, as well as significantly different from the ratios calculated for the larger intervals).[6] Another distinguishing feature of the distribution seen in Panel C of Table 1 and evident in both Panels A and B of Fig. 1 is the large number of exactly zero observations (12%). Depending on one's previous exposure to the data or instincts about the task of forecasting, the magnitude of the clustering at exactly zero may not seem

[5] The visual evidence in Panel B of Fig. 1 is consistent with specific circumstances in which analysts have incentives to produce forecasts that fall slightly short of reported earnings (see, e.g., Degeorge et al., 1999; Matsumoto, 2002; Brown, 2001; Burgstahler and Eames, 2002; Bartov et al., 2000; Dechow et al., 2003; Abarbanell and Lehavy, 2003a, b). However, prior studies have not considered the impact of observations that comprise the middle asymmetry on inferences concerning the *general* tendency of analysts to produce biased and/or inefficient forecasts.

[6] An analysis of unscaled forecast errors confirms that rounding down a greater number of negative than positive forecast errors to a value of zero when errors are scaled by price does not systematically induce the middle asymmetry (see, Degeorge et al., 1999). Similarly, there is no obvious link between the presence of the middle asymmetry and round-off errors induced by the application of stock-split factors to consensus forecast errors discussed in Baber and Kang (2002) and Payne and Thomas (2002). Abarbanell and Lehavy (2002) present evidence confirming the presence of the middle asymmetry in samples confined to firms with stock-split factors of less than 1.

surprising. Nevertheless, the large number of forecasts of exactly zero has important impacts on statistical inferences.[7]

The statistics presented above indicate that the tail asymmetry pulls the mean forecast error toward a negative value, supporting the case for analyst optimism. But, as shown in Panel C of Table 1, the excess of *small* positive over *small* negative errors associated with the middle asymmetry is largely responsible for a significantly higher overall incidence of positive to negative forecast errors in the distribution, thus supporting the case for analyst pessimism. Finally, a zero median forecast error, which supports an inference of analyst unbiasedness, reflects the countervailing effects of the middle asymmetry and tail asymmetries. A rough calculation pertaining to the nonzero forecast errors in the interval between [−0.1, 0) and (0, 0.1] gives a sense of these effects. There are 9662 observations in this region. If nonzero forecast errors were random, we would expect 4831 forecasts to be positive, when in fact 5928 are positive, indicating that small errors in the distribution of absolute magnitude less than or equal to 0.1 contribute 1097 more observations to the right of zero than would be expected if the distribution was symmetric. This region of the forecast error distribution contains 29% of all observations but contributes more than 42% of the total number of pessimistic errors in excess of optimistic errors and represents roughly 3.3% of the entire distribution. Their impact offsets, all else being equal, the contribution of approximately 2.5% of negative observations in excess of what would be expected if the distribution of errors were symmetric, arising from the tail asymmetry (relative to the extreme decile cutoffs of a fitted normal distribution). Because 12% of the forecast error sample has a value of exactly zero, the relative sizes of the tail and middle asymmetries are each sufficiently small (and offsetting) to ensure that the median error remains at zero.

The evidence in Table 1 and Fig. 1 yields two important implications for drawing inferences about the nature and extent of analyst bias. First, depending on which summary statistic the researcher chooses to emphasize, support can found for analyst optimism, pessimism, and even unbiasedness. Second, if a researcher relies on a given summary statistic to draw an inference about analyst bias, a relatively small percentage of observations in the distribution of forecast errors will be responsible for his or her conclusion. This is troublesome because extant hypotheses that predict analyst optimism or pessimism typically do not indicate how often the phenomenon will occur in the cross-section and often convey the impression that

[7] Because many factors can affect the process that generates the typical distribution of forecast errors, there is no reason to expect them to be normally or even symmetrically distributed. Supplemental analyses unreported in the tables reject normality on the basis of skewness and kurtosis. It is interesting to note, however, that kurtosis in the forecast error distribution does not align with the typical descriptions of leptokurtosis (high peak and fat tails) or platykurtosis (flat center and/or shoulders). Relative to decile cutoffs of the fitted normal distribution, we find that the most extreme negative decile of the actual distribution contains only 5% of the observations and the most extreme positive decile contains only 2.5% of the observations. Thus, even though the extreme negative tail is roughly twice the size of the extreme pessimistic tail, extreme observations are actually *underrepresented* in the distribution relative to a normal, especially in the positive tail. The thinner tails and shoulders of the distribution highlight the role of peakedness as a source of deviation from normality, a fact that is relevant to assessing the appropriateness of statistics used by researchers to draw inferences about analyst forecast bias.

bias will be pervasive in the distribution (see, studies suggesting that analysts are hard-wired or motivated to produce optimistic forecasts, e.g., Affleck-Graves et al. (1990), Francis and Philbrick (1993), and Kim and Lustgarten (1998), or that selection biases lead to hubris in analysts' earnings forecasts, e.g., McNichols and O'Brien, 1997).[8]

Some studies have explicitly recognized the disproportional impact of extreme negative forecast errors on conclusions drawn in the literature, but for the most part they have had little influence on general perceptions. For example, Degeorge et al. (1999) predict a tendency for pessimistic errors to occur but recognize the common perception that analyst forecasts are optimistic; they note in passing that extreme negative forecast errors are responsible for an optimistic mean forecast in their sample. Some studies also tend to deal with this feature of the data in an ad hoc manner. Keane and Runkle (1998), for example, recognize the impact of extreme negative forecast errors on statistical inferences concerning analyst forecast rationality and thus eliminate observations from their sample based on whether reported earnings contain large negative special items. However, Abarbanell and Lehavy (2002) show that there is a very high correlation between observations found in the extreme negative tail of forecast error distributions and firms that report large negative special items, even when special items are excluded from the reported earnings benchmark used to calculate the forecast error. Thus, by imposing rules that eliminate observations from their sample based on the size of negative special items, Keane and Runkle (1998) effectively truncate the extreme negative tail of forecast error distributions, and in so doing nearly eliminate evidence of mean optimism in their sample.

Some researchers are less explicit in justifying the removal of observations from the distribution of forecast errors when testing for forecast rationality, or are unaware that they have done so in a manner that results in sample distributions that deviate substantially from the population distribution. For example, many studies implicitly limit observations in their samples to those that are less extreme by choosing ostensibly symmetric rules for eliminating them, such as winsorization or truncations of values greater than a given absolute magnitude.[9] It should be evident from Panel A of Fig. 1 that such rules inherently mitigate the statistical impact of the

[8] A notable exception is the attribution of optimism in analysts' earnings forecasts to incentives to attract and maintain investment banking relationships (see, e.g., Lin and McNichols, 1998; Dugar and Nathan, 1995). Evidence consistent with this argument is based on fairly small samples of firms issuing equity. We emphasize that all the qualitative results in this paper are unaltered after eliminating observations for which an IPO or a seasoned equity offering took place within 1 year of the date of a forecast. Furthermore, the number of observations removed from the sample for this reason represents a very small percentage of those in each of the quarters in our sample period.

[9] For example, Kothari (2001) reports that Lim (2001) excludes absolute forecast errors of \$10 per share or more, Degeorge et al. (1999) delete absolute forecast errors greater than 25 cents per share, Richardson et al. (1999) delete price-deflated forecast errors that exceed 10% in absolute value, and Brown (2001) winsorizes absolute forecast errors greater than 25 cents per share (which implies a much larger tail winsorization than typically undertaken to remove possible data errors). While none of these procedures, when applied to our data, completely eliminates the tail asymmetry, all of them substantially attenuate to varying degrees its statistical impact on our tests.

tail asymmetry and arbitrarily transform the distribution, frequently without a theoretical or institutional reason for doing so.[10]

One might justify truncating data on the grounds that the disproportional impact of the extreme tail makes it difficult detect general tendencies, or that such "errors" may not accurately reflect factors relevant to analysts' objective functions (see, e.g., Abarbanell and Lehavy, 2003b; Gu and Wu, 2003; Keane and Runkle, 1998). However, it is possible for researchers to "throw the baby out with the bathwater" if they assume that these observations do not reflect the effects of incentives or cognitive biases, albeit in a more noisy fashion than other observations in the distribution. Another concern that arises from transforming the distribution of errors without justification is that it may suppress one feature of the data (e.g., the tail asymmetry), leaving another unusual but more subtle feature of the distribution (e.g., the middle asymmetry) to dominate an inference that forecasts are generally biased or to offset the other and yield an inference that forecasts are generally unbiased. This is an important issue because there has been a tendency in the literature on forecast rationality for new hypotheses to crop up motivated solely by the goal of explaining "new" empirical results. For example, after truncating large absolute values of forecast errors, Brown (2001) finds that the mean and median forecasts in recent years indicate a shift away from analyst optimism and toward analyst pessimism. Increasing pessimism as a function of market sentiment as reflected in changes in price level or changes in analyst incentives has also been a subject of growing interest in the behavioral finance literature. Clearly, when data inclusion rules that systematically reduce the tail asymmetry are applied, empirical evidence in support of increasing or time-varying analyst pessimism will be affected by the size and magnitude of the remaining middle asymmetry.

Perhaps the most unsatisfying aspect of the evidence presented in Table 1 is the fact that general incentive and behavioral theories of analyst forecast errors are not sufficiently developed at this stage to predict that when forecast errors are extreme they are more likely to be *optimistic* and when forecast errors are small they are more likely to be *pessimistic*. That is, individual behavioral and incentive theories for analyst forecast errors do not account for the simultaneous presence of the two asymmetries that play such an important role in generating evidence consistent with analyst bias and, as we show in the next section, analyst forecast inefficiency with respect to prior information (see Abarbanell and Lehavy, 2003a, for an exception).

3. The effect of the two asymmetries on evidence of apparent analyst misreaction to prior stock returns, prior earnings changes, and prior forecast errors

In this section, we demonstrate how observations that comprise the tail and middle asymmetries in forecast error distributions *conditional on prior realizations of*

[10] For example, in our data an arbitrary symmetric truncation of the distribution at the 10th and the 90th percentiles reduces the measure of skewness in the remainder of the distribution to a level that does not reject normality and results in a mean forecast error near zero among the remaining observations. A similar effect occurs with an arbitrary one-sided truncation of the negative tail at a value as low as the 3rd percentile.

economic variables contribute to inconsistent inferences concerning the efficiency of analysts' forecasts. One important message of the ensuing analysis is that the likelihood that a forecast error observation falls into one or the other asymmetry varies by the sign and magnitude of the prior news. This feature of the data links the empirical literature on analyst inefficiency to the heretofore separate literature on analyst bias. This is because observations that comprise the two asymmetries and lead—depending on the statistic relied on—to inconsistent inferences concerning analyst bias also contribute to conflicting inferences concerning whether analysts underreact, overreact, or react efficiently to prior news.

We consider realizations of three economic variables: prior period stock returns, prior period earnings changes, and prior period analyst forecast errors. These three variables are those most often identified in previous studies of analyst forecast efficiency.[11] Consistent with the previous literature, we define prior abnormal returns (*PrAR*) as equal to the return between 10 days after the last quarterly earnings announcement to 10 days prior to the current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period.[12] Prior earnings changes (*PrEC*) are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the price at the beginning of the period, and prior forecast errors (*PrFE*) are the prior quarter's forecast error.

The remainder of this section proceeds as follows: we first present evidence on the existence of the tail and middle asymmetries in distributions of forecast errors conditional on the sign of prior news variables. We then analyze the role of the asymmetries in producing indications of analyst inefficiency in both summary statistics and regression coefficients and discuss the robustness of these findings. Next, we show the disproportionate impact of observations that comprise the asymmetries in generating evidence of serial correlation in analyst forecast errors. Finally, we discuss the shortcomings of econometric "fixes" that intentionally or unintentionally ameliorate the impact of one or both asymmetries on inferences concerning analyst forecast rationality.

3.1. The tail and middle asymmetries in forecast error distributions conditional on prior news variables

Tests of analyst forecast efficiency typically partition distributions of forecast errors based on the sign of the prior news to capture potential differences in analyst reactions to prior good versus prior bad news. Accordingly, before we review the

[11] Studies that examine the issue of current period forecast efficiency with respect to prior period realization of returns or earnings (e.g., Abarbanell, 1991; Easterwood and Nutt, 1999) commonly frame the question in terms of whether analysts over- or underreact to prior news. In contrast, studies that examine the issue of current period forecast efficiency with respect to analysts' own past forecast errors are generally limited to the question of whether there is significant serial correlation in lagged forecast errors, without regard to how the sign and magnitude of prior forecast errors affect that correlation.

[12] All reported results are qualitatively similar when prior abnormal returns are measured between 10 days after the last quarterly earnings announcement to either 30 days prior or 1 day prior to the current quarter earnings announcement.

statistical evidence, we first examine the features of forecast error distributions conditional on the sign of prior news variables. Panels A–C of Fig. 2, which depict the percentiles of the distributions of forecast errors conditional on the sign of each of the three prior news variables, show that prior bad news partitions are characterized by larger tail asymmetries than prior good news partitions for all prior news variables.

Panels A–C of Fig. 3—which depict the frequencies of forecast errors that fall in fixed subintervals of 0.025 within the range of -0.5 to $+0.5$ for *PrAR*, *PrEC*, and *PrFE*, respectively—show that prior good news partitions are characterized by larger middle asymmetries than prior bad news partitions for all three prior news variables.[13]

Together, Figs. 2 and 3 suggest that distributions of forecast errors conditional on the sign of prior news retain the characteristic asymmetries found in the unconditional distributions in Section 2. However, the likelihood of a subsequent forecast error falling into the middle asymmetry is greater following prior good news, while the likelihood of a forecast error falling into the tail asymmetry is greater following prior bad news.[14] Below we investigate the impact of the variation in the size of the asymmetries in distributions of forecast errors conditional on the sign of news on inferences about analyst inefficiency that are drawn from summary statistics (Section 3.1.1) and regression coefficients (Section 3.1.2).

3.1.1. Inferences about analyst efficiency from summary statistics

Panel A of Table 2 shows how the two asymmetries impact summary statistics, including means, medians, and the percentages of negative to positive forecast errors in distributions of forecast errors conditional on the sign of prior news. We begin with the case of prior bad news. Prior bad news partitions for all three variables produce significantly negative mean forecast errors (-0.195 for *PrAR*, -0.291 for *PrEC*, and -0.305 for *PrFE*), supporting an inference of analyst underreaction (i.e., the mean forecast is too high following bad news). The higher percentages of negative than positive forecast errors in the bad news partitions of each variable (e.g., 50% vs. 40% for negative *PrEC*) are also consistent with a tendency for analysts to underreact to prior bad news. The charts in Figs. 2 and 3 foreshadow these results. The relatively larger tail asymmetry in prior bad news partitions drives parametric means to large negative values. Similarly, the larger negative relative to

[13] The concentration of small (extreme) errors among positive (negative) prior returns news is not induced by scaling by prices that are systematically higher (lower) following a period of abnormal positive (negative) returns, since the middle and tail asymmetries are still present in distributions of unscaled forecast errors and errors deflated by forecasts.

[14] Abarbanell and Lehavy (2003a) report the same patterns in forecast error distributions conditional on classification of ranked values of stock recommendations, P/E ratio, and market-to-book ratios into high and low categories. It is certainly possible that some form of irrationality or incentive effect leads to different forecast error regimes on either side of a demarcation point of zero, and therefore coincidentally sorts the two asymmetries that are located on either side of a zero. However, the continued presence of relatively small but statistically influential asymmetries in the conditional distributions may overwhelm the researcher's ability to detect these incentive or behavioral factors, or may give the false impression that such a factor is pervasive in the distribution when it is not.

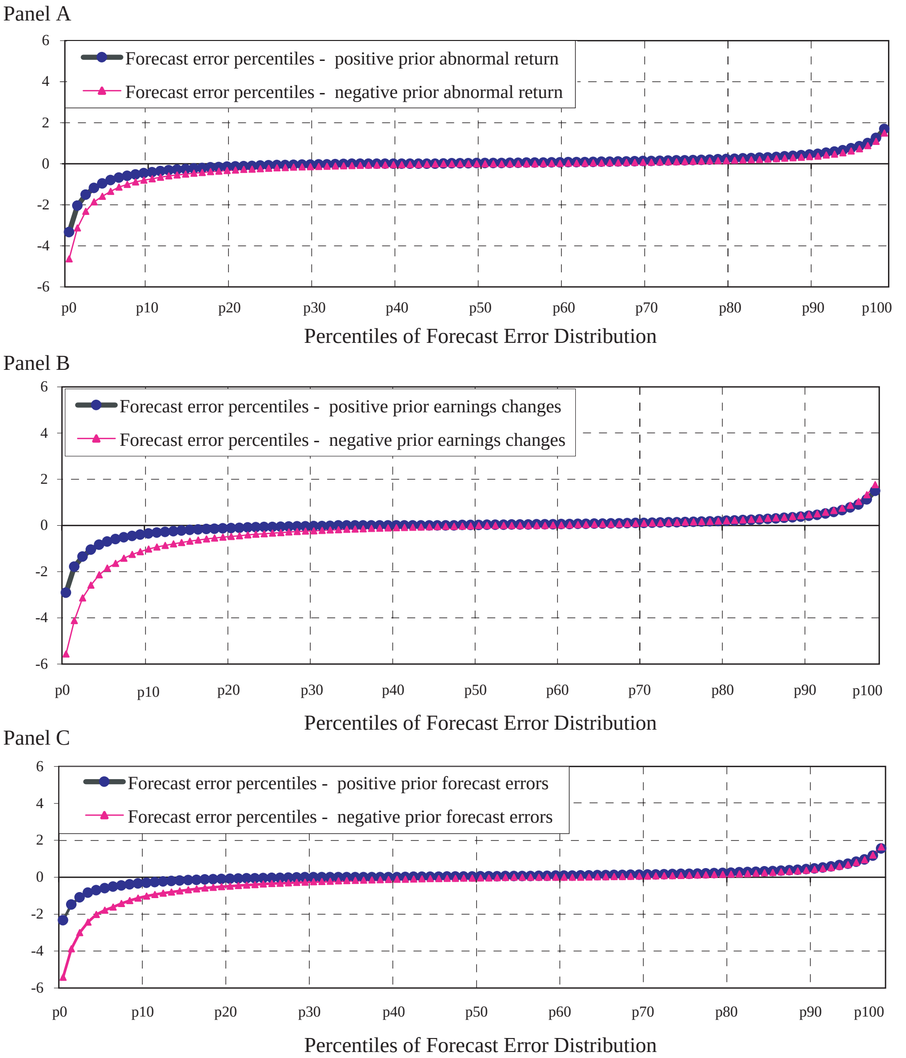

Fig. 2. Forecast error equals reported earnings minus consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Prior market-adjusted return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price.

positive tails account for greater overall frequencies of negative than positive errors, consistent with underreaction to bad news for all three variables. This is so even though prior bad news distributions of forecast errors for *PrAR* and *PrEC* are characterized by middle asymmetries, which, all else equal, tend to push the ratio of positive to negative errors toward values greater than 1.

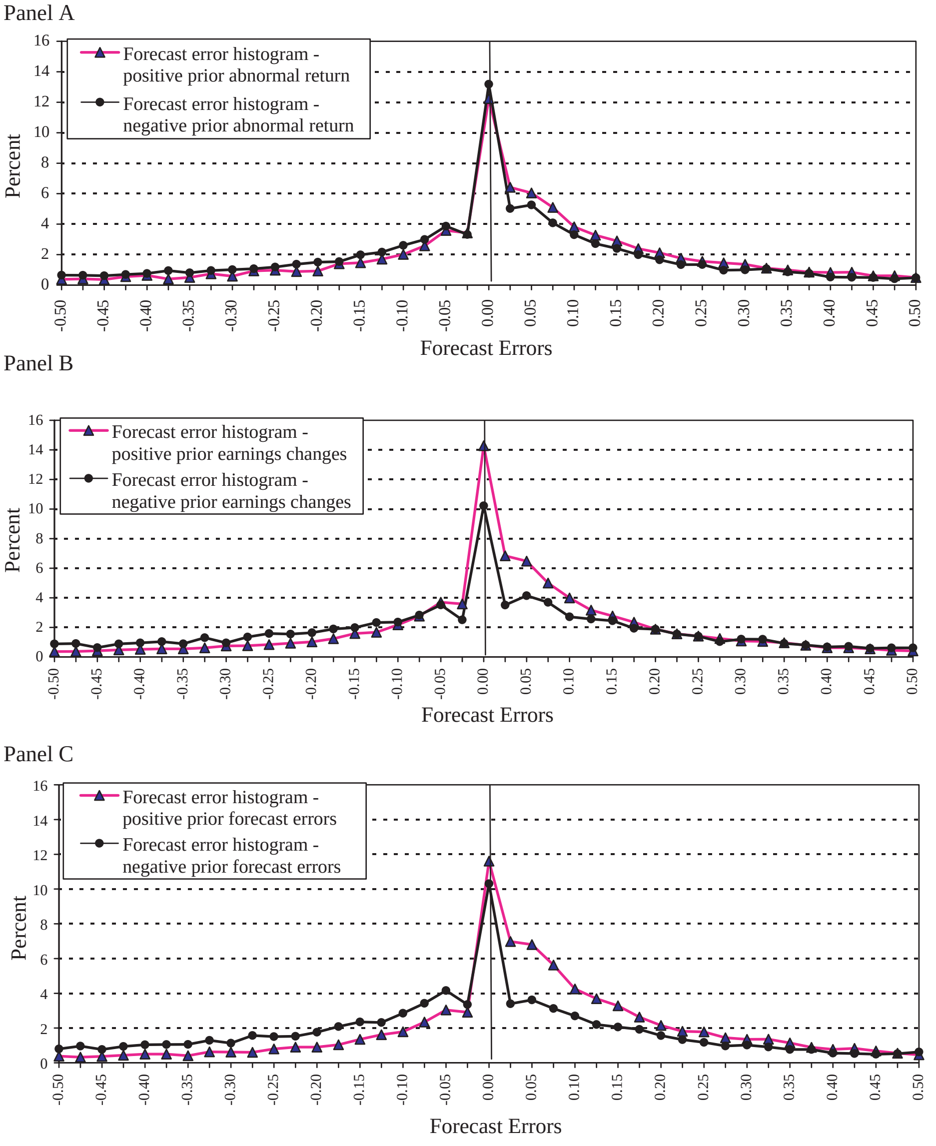

Fig. 3. Histogram of forecast errors by sign of prior abnormal returns (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). This figure presents the percentage of forecast error values in histogram intervals for observations within forecast error of -0.5 to $+0.5$ by sign of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price.

Table 2
Mean, median, and frequency of forecast errors (Panel A), and ratio of positive to negative forecast errors in symmetric regions for bad (Panel B) and good (Panel C) prior news variables

Panel A: Mean, median, and frequency of forecast errors by sign of prior news variables

Statistic	Sign of prior abnormal return		Sign of prior earnings changes		Sign of prior forecast errors	
	Negative (1)	Positive (2)	Negative (3)	Positive (4)	Negative (5)	Positive (6)
Mean	−0.195*	−0.041*,#	−0.291*	−0.036*,#	−0.305*	0.017*,#
Median	0.000	0.028	−0.015	0.020	−0.043	0.042
% Zero forecast errors	13%	12%	10%	14%	10%	11%
% Positive forecast errors	42%	54%	40%	52%	36%	59%
% Negative forecast errors	45%	34%	50%	34%	54%	30%
N	16,940	13,833	11,526	21,062	12,999	15,415

Panel B: Ratio of positive to negative forecast errors for negative *realizations of prior news*

Range of forecast errors	Negative prior abnormal return		Negative prior earnings changes		Negative prior forecast errors	
	Ratio of positive to negative FE (1)	% of total (2)	Ratio of positive to negative FE (3)	% of total (4)	Ratio of positive to negative FE (5)	% of total (6)
Overall	0.94	100	0.81	100	0.66	100
Forecast errors = 0		13		10		10
[−0.1, 0) & (0, 0.1]	1.39	27	1.26	21	0.94	23
[−0.2, −0.1) & (0.1, 0.2]	1.27	17	1.15	17	0.94	17
[−0.3, −0.2) & (0.2, 0.3]	0.99	10	0.93	11	0.75	10
[−0.4, −0.3) & (0.3, 0.4]	0.96	7	0.93	8	0.72	7
[−0.5, −0.4) & (0.4, 0.5]	0.73	5	0.74	6	0.59	5
[−1, −0.5) & (0.5, 1]	0.60	11	0.56	14	0.52	14
[Min, −1) & (1, Max]	0.29	10	0.28	14	0.24	14

Panel C: Ratio of positive to negative forecast errors for positive *realizations of prior news*

Range of forecast errors	Positive prior abnormal return		Positive prior earnings changes		Positive prior forecast errors	
	Ratio of positive to negative FE (1)	% of total (2)	Ratio of positive to negative FE (3)	% of total (4)	Ratio of positive to negative FE (5)	% of total (6)
Overall	1.58	100	1.53	100	1.99	100
Forecast errors = 0		12		14		11
[−0.1, 0) & (0, 0.1]	1.86	31	1.82	33	2.33	33
[−0.2, −0.1) & (0.1, 0.2]	1.89	18	1.85	18	2.42	19
[−0.3, −0.2) & (0.2, 0.3]	1.85	10	1.66	9	2.22	10
[−0.4, −0.3) & (0.3, 0.4]	1.70	6	1.49	6	2.03	7
[−0.5, −0.4) & (0.4, 0.5]	1.52	5	1.28	4	1.70	4
[−1, −0.5) & (0.5, 1]	1.25	10	1.17	9	1.44	10
[Min, −1) & (1, Max]	0.62	8	0.58	7	0.83	6

Panel A provides statistics on forecast errors (FE) by sign of prior abnormal return, prior earnings changes, and prior forecast errors. Panel B (Panel C) reports the ratio of positive to negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors for negative (positive) prior abnormal returns, prior earnings changes, and prior forecast errors. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

*Significantly different than zero at a 1% level or better.

#Mean forecast error for positive prior news variables is significantly different than mean forecast error for negative prior news variables at a 1% level or better.

The impact of the tail asymmetry on the inference of underreaction to prior bad news can be seen in Panel B of Table 2, which presents the number of observations in increasingly larger nonoverlapping symmetric intervals starting from zero for the three prior bad news partitions. Even though large errors in the intervals [min, −1) and (1, max] make up a relatively small percentage of the observations in the bad news distributions of *PrAR*, *PrEC*, and *PrFE* (10%, 14%, and 14%, respectively), errors of these absolute magnitudes comprise 3.45 (=1/0.29) 3.57 (=1/0.28), and 4.17 (=1/0.24) bad news observations for every good news observation, respectively.

Apparent consistency across summary statistical indicators of analyst underreaction to prior bad news does not carry over to the case of prior good news. The mean error for the good news partitions of *PrAR* and *PrEC* reported in columns 2 and 4 of Panel A of Table 2 are negative, consistent with analyst *overreaction* (i.e., the mean forecast is too high following good news), but is positive in the case of good news *PrFE*, suggesting *underreaction*. These mixed parametric results are attributable to the fact that tail asymmetries, although relatively small compared to their bad news counterparts, are still sufficiently large to produce negative mean errors for both prior good news partitions of *PrAR* and *PrEC* (see Fig. 2). However, they are not large enough to generate a negative median for these variables because, as seen in Panel C of Table 2, there is an even greater *frequency* of small positive errors associated with middle asymmetries in the good news partitions than for unconditional distributions (e.g., the ratio of positive errors to negative errors is 1.86 in the interval [−0.1, 0), (0, 0.1] of the *PrAR* partition but only 1.63 in that same interval of the unconditional distribution). The middle asymmetries are thus sufficiently large to offset relatively small tail asymmetries in these good news partitions, leading to indications of underreaction to good news in nonparametric statistics.[15]

3.1.2. *Inferences about analyst efficiency from regression analysis*

While means, medians, and ratios of positive to negative forecast errors are viable statistics from which to draw inferences of analyst inefficiency, most studies rely on slopes of regressions of forecast errors on prior news variables. The most persistent findings from such regressions are significant positive slope coefficients that are consistent with overall analyst *underreaction* to prior news realizations. To examine

[15] In this study, as in any study that partitions prior news variables by sign, we treat all prior variables as if they were interchangeable for the purposes of drawing inferences concerning a general tendency toward analyst inefficiency. Clearly, partitioning on the sign of news is likely to lead to misclassification in the case of prior earnings news, since the average firm is *not* likely to have an expected change of zero. Moreover, both prior earnings changes and prior forecast errors entail the use of an earnings benchmark, which, as discussed in the next section, introduces another potential problem of classification associated with potential time-series correlations induced by earnings management. These are interesting issues worthy of further consideration. However, they do not preclude an analysis of how the tail and middle asymmetries in forecast error distributions have combined to generate inconsistent indications of analyst inefficiency in the existing literature. If anything, these issues further strengthen the case for adopting the approach of identifying salient features of distributions of forecast errors in an effort to develop more precise hypotheses and design more appropriate empirical tests.

Table 3
Slope coefficients from OLS and rank regressions of forecast errors on prior news variables

	Explanatory variable					
	Prior abnormal return		Prior earnings changes		Prior forecast errors	
	OLS	Ranked	OLS	Ranked	OLS	Ranked
Overall	0.744	0.162	0.819	0.160	0.238	0.253
	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Prior bad news	1.602	0.213	2.306	0.130	0.231	0.265
	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Prior good news	0.089	0.199	−0.835	0.157	0.045	0.170
	0.28	<0.01	0.01	<0.01	0.11	<0.01

This table reports slope coefficient estimates from OLS and rank regressions of forecast errors on prior abnormal return, prior earnings changes, and prior forecast errors with the White-corrected p-values. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

the effect of the two asymmetries on this inference, we first estimate the slope coefficients for separate OLS and rank regressions of forecast errors on *PrAR*, *PrEC*, and *PrFE*. After applying White corrections suggested by the regression diagnostics, the estimates, as shown in the first row of Table 3, confirm that the typical finding reported in the prior literature of overall underreaction holds for all three prior news variables in our sample, inasmuch as all three coefficients are positive and reliably different from zero. Similarly, rank regressions produce significant positive slope coefficients in the case of all three prior news variables.

Next, we compare the inferences from regression slope coefficients estimated by the sign of prior news to assess their consistency with the parametric and nonparametric evidence presented in Panel A of Table 2 and the preceding regression results for the overall samples. These results are presented in Table 3. Consistent with regression results for the overall sample, prior bad news partitions of all three variables produce OLS and rank slope coefficients that are significantly positive, indicating once again analyst underreaction to prior bad news. These results are consistent with indications of underreaction in both the parametric and nonparametric summary statistics associated with all three bad news partitions reported in Panel A of Table 2. In sharp contrast, however, regression results for the prior good news partitions generate inconsistent indications across both OLS and rank regression slope coefficients and across prior news variables. The OLS slope coefficient is positive but insignificant in the case of good news *PrAR* and *PrFE*, resulting in a failure to reject efficiency in these cases, but it is reliably negative for the good news *PrEC* variable, consistent with analyst *overreaction* to prior good earnings news. That is, OLS performed on the prior good news partitions of forecast errors produces *no* evidence of apparent analyst underreaction observed both in the overall samples and in the prior bad news partitions. In contrast, and adding to the ambiguity, rank regressions do produce reliably positive slope coefficients consistent with underreaction for all three prior good news variables. This finding is also consistent with the rank regression results for both the overall samples and the prior bad news partitions for all three prior news variables that suggest analyst underreaction.

It is evident from the foregoing collection of parametric and nonparametric results that it is difficult to draw a clear inference regarding the existence and nature of analyst inefficiency with respect to prior news. These results are a microcosm of similar inconsistencies found in the literature on analyst efficiency with respect to prior news, examples of which are discussed below. In keeping with our goal of assessing the extent, to which theories that predict systematic errors in analysts forecasts are supported by the evidence, we next delve further into the robustness of specific findings concerning analyst-forecast efficiency. As in the case of inferences on bias in analysts' forecasts, we find inconsistencies and a lack of robustness of evidence, which are linked to the relative size of the two asymmetries present in forecast error distributions.

3.2. How robust is evidence of analyst underreaction to bad news?

To further isolate the disproportional influence of the asymmetries on statistics, we examine the relation between forecast errors and prior news variables in finer partitions of the prior news variables. Our goal is to demonstrate that while the statistical indications of analyst underreaction to prior bad news are largely consistent in Tables 2 and 3, the phenomenon is not robust in the distribution of forecast errors. Fig. 4 depicts the percentiles of the distributions of forecast errors for the lowest, highest, and the combined distribution of the 2nd through the 9th decile of each prior news variable. One pattern evident in all of the panels is that the most extreme prior bad news decile is always associated with the most extreme negative forecast errors.

The effect of this association is evident in Fig. 5, which summarizes the mean and median forecast errors by decile of prior news for all three variables: The largest negative mean error by far is produced in the 1st decile of all prior news variables. This finding helps explain why overall bad news partitions of prior news yield parametric means that are always consistent with analyst underreaction.[16]

To gauge the effect of observations in the lowest prior news decile (which, as seen in Fig. 4, are associated with extreme negative forecast errors), we reestimate the

[16] Furthermore, in unreported results we find that OLS regressions by individual deciles produce significant positive coefficients in *only* the 1st decile among all deciles associated with prior bad news for all three prior variables. The combination of greater (lower) variation in the independent variable and a strong linear (nonlinear) relation between prior news and forecast errors in the first decile (other deciles) contribute to these results, as we discuss later.

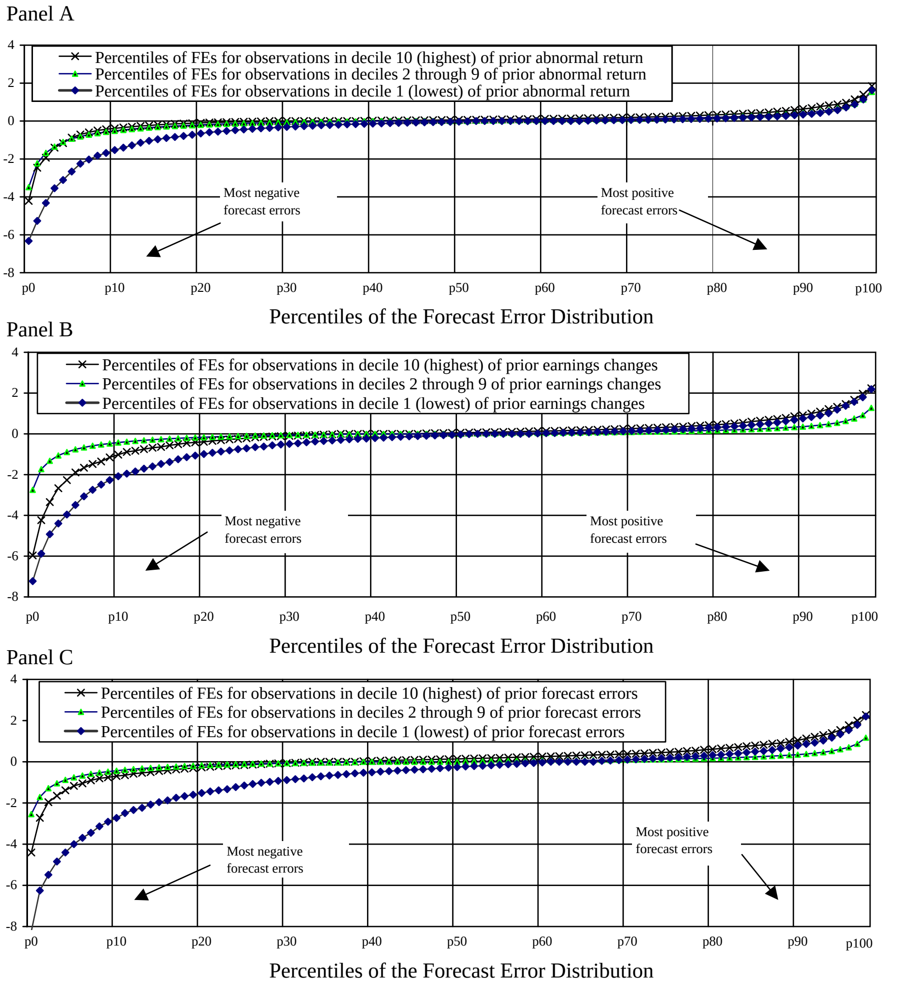

Fig. 4. The tail asymmetry in forecast errors within selected deciles of prior news variables. This figure depicts percentiles of quarterly distributions of analysts' forecast errors that fall in selected deciles (lowest, highest, and the combined distribution of the 2nd through the 9th decile) of prior abnormal returns (Panel A) prior earnings changes (Panel B) and prior forecast errors (Panel C). Forecast error equals reported earnings minus consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Prior market-adjusted return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price.

OLS regressions for the overall sample after excluding observations in this decile (unreported in the tables). We find that removing the 1st decile of prior news results in declines in the overall coefficients from values of 0.744, 0.819, and 0.238, to values

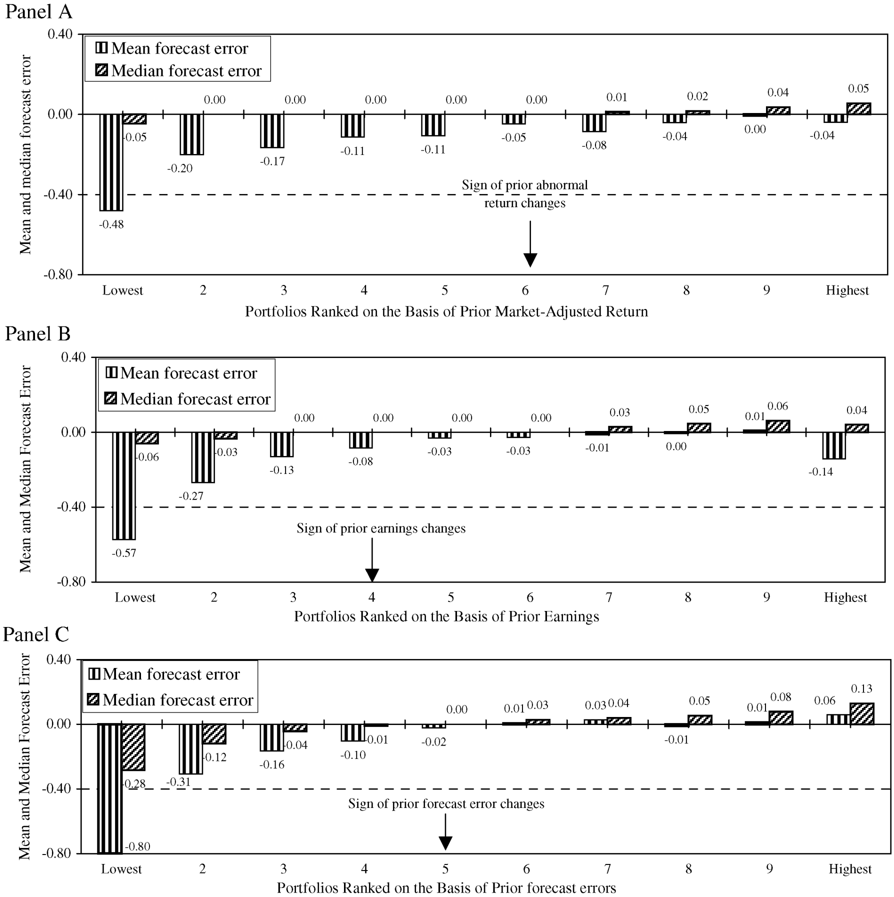

Fig. 5. Mean and median forecast errors by decile ranking of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). This figure depicts mean and median forecast errors for portfolios ranked on the basis of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast errors (Panel C). Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

of 0.380, −0.559, and 0.194, for *PrAR*, *PrEC*, and *PrFE*, respectively, and *t*-statistics are significantly reduced in each case. Removal of individual deciles 2–9 before reestimating the regressions leads to virtually no change in the coefficients for all three prior news variables, whereas removal of the 10th decile actually leads to increases in the coefficients for all three variables. Notably, the disproportionate influence of extreme forecast error observations associated with extreme prior news is an effect that is not specifically predicted by extant behavioral or incentive-based theories of analyst inefficiency.[17]

The middle asymmetry also contributes, albeit more subtly than the tail asymmetry, to producing OLS regression coefficients that are consistent with underreaction to bad news. As seen in the first row of Panels A–C of Table 4 ("Overall"), which presents the ratio of positive to negative forecast errors by deciles of all three prior news variables, the percentage of positive errors increases as prior news improves. Consider, for example, in Panel A, the evidence for the first 5 deciles of *PrAR*, which only pertain to prior bad news realizations. The steadily increasing rate of small positive errors as *PrAR* improves will contribute to a positive slope coefficient in OLS regressions of forecast errors on prior bad news, reinforcing an inference of underreaction from this statistic. The concern raised by evidence in the remaining rows of Panel A of Table 4 is that less extreme prior bad news generates increasingly higher incidences of small positive versus small negative forecast errors—that is, observations that represent exactly the opposite of analyst underreaction.

Finally, recall that nonparametric statistics, including percentages of negative errors, rank regression slopes, and medians, also provide consistent indications of analyst underreaction to bad news. The nonparametric evidence in Panel A of Table 4 suggests however that this finding is also not as robust as it first appears. In the case of *PrAR*, for example, only the two most extreme negative deciles are associated with a reliably higher frequency of negative errors, which would not be expected if analyst underreaction to bad news was a pervasive phenomenon. In fact, there is a monotonic increase in the rate of positive to negative errors in the deciles that contain bad news realizations, with the 3rd decile containing a statistically equal number of each, and deciles 4–6 containing a reliably *greater* number of positive than negative errors.[18] Thus, observations that form the tail asymmetry, which is most pronounced in extreme bad news *PrAR*, even have a disproportional impact on some nonparametric evidence of underreaction to bad news, including indications from medians, percentages of negative errors, and rank regressions.[19]

[17] It is not well recognized that the inference of underreaction to prior bad news generated by the parametric tests favored in the literature is common to all prior news variables and is always driven by the concentration of extreme negative errors associated with extreme prior bad news. This conclusion can be drawn from studies investigating over/underreaction to prior returns (see, e.g., Brown et al., 1985; Klein, 1990; Lys and Sohn, 1990; Abarbanell, 1991; Elgers and Murray, 1992; Abarbanell and Bernard, 1992; Chan et al., 1996) and studies investigating over/underreaction to prior earnings changes (see, e.g., De Bondt and Thaler, 1990; Abarbanell and Bernard, 1992; Easterwood and Nutt, 1999).

[18] The 6th decile of *PrAR* includes small negative, small positive, and a limited number of zero observations. The demarcation point of zero occurs in the 4th decile of *PrEC*, reflecting a greater likelihood of positive earnings changes than negative earnings changes. The demarcation occurs in the 5th decile of *PrFE*, reflecting both a high percentage of zero prior forecast errors as well as the higher incidence overall of positive versus negative errors associated with the middle asymmetry. As suggested in footnote 15, simply partitioning prior news at the value of zero (as is done in the literature) may not lead to appropriate comparisons with respect to analyst efficiency across prior news variables in all situations.

[19] Recall that rank regressions of forecast errors and prior news produce large positive and significant slope coefficients, consistent with underreaction to bad news prior returns even though the incidence of positive errors is equal to or greater than the incidence of negative forecast errors in all but the most

Table 4
Ratio of small positive to small negative forecast errors in symmetric regions by decile ranking of prior abnormal return (Panel A), prior earnings changes (Panel B), and prior forecast error (Panel C)

Range of forecast errors	Lowest	2	3	4	5	6	7	8	9	Highest
Panel A: Ratio of small positive to small negative forecast errors and percentage of total decile observations within deciles of prior abnormal return										
Overall	0.66	0.78	0.97	1.08	1.17	1.27	1.33	1.39	1.76	2.12
[−0.1, 0) & (0, 0.1]	1.39	1.12	1.35	1.51	1.53	1.61	1.66	1.75	1.84	2.43
	24%	30%	32%	34%	35%	36%	38%	36%	34%	31%
[−0.2, −0.1) & (0.1, 0.2]	1.11	1.16	1.26	1.24	1.49	1.53	1.46	1.54	2.41	2.60
	18%	19%	21%	19%	20%	21%	20%	20%	21%	21%
[−0.3, −0.2) & (0.2, 0.3]	0.75	0.83	0.99	1.15	1.14	1.31	1.72	1.56	2.02	2.64
	10%	11%	11%	11%	12%	12%	11%	12%	12%	11%
Panel B: Ratio of small positive to small negative forecast errors and percentage of total decile observations within deciles of prior earnings changes										
Overall	0.75	0.77	0.86	0.91	1.16	1.53	1.83	1.87	1.83	1.45
[−0.1, 0) & (0, 0.1]	1.52	1.30	1.18	1.14	1.38	2.10	2.36	2.07	2.00	1.98
	16%	21%	28%	41%	56%	54%	45%	33%	25%	18%
[−0.2, −0.1) & (0.1, 0.2]	1.25	1.15	1.11	1.08	1.29	1.57	2.24	2.54	2.20	1.91
	13%	19%	21%	23%	19%	20%	24%	25%	22%	15%
[−0.3, −0.2) & (0.2, 0.3]	0.97	0.98	0.91	0.79	0.93	1.19	2.03	2.17	1.98	2.19
	9%	12%	13%	12%	7%	9%	11%	13%	13%	11%
Panel C: Ratio of small positive to small negative forecast errors and percentage of total decile observations within deciles of prior forecast errors										
Overall	0.53	0.58	0.70	0.74	1.32	2.25	2.06	1.91	1.95	1.82
[−0.1, 0) & (0, 0.1]	1.10	0.90	0.91	0.87	1.50	3.02	2.22	2.05	2.09	1.65
	8%	15%	24%	37%	65%	58%	46%	33%	24%	13%
[−0.2, −0.1) & (0.1, 0.2]	1.27	0.94	0.88	0.90	1.16	2.17	2.68	2.59	2.75	1.99
	10%	17%	23%	25%	18%	21%	24%	25%	23%	16%
[−0.3, −0.2) & (0.2, 0.3]	0.90	0.71	0.69	0.64	1.28	1.69	2.16	2.66	2.20	2.32
	9%	12%	14%	11%	7%	8%	10%	14%	15%	13%

This table reports the ratio of small positive to small negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors and the percentage of observations that fall in these intervals of the total nonzero forecast errors in that decile. Prior abnormal return is the return between 10 days after the last quarterly earnings announcement to 10 days prior to current quarterly earnings announcement minus the return on the value-weighted market portfolio for the same period. Prior earnings changes are defined as the prior quarter seasonal earnings change (from quarter $t-5$ to quarter $t-1$) scaled by the beginning-of-period price. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by price.

(*footnote continued*)
extreme deciles of bad news *PrAR*. This occurs because the most negative ranks of *PrAR* are paired with the most negative forecast errors, which when combined with the increasing incidence of pessimistic errors as bad news becomes less extreme (in principle, overreaction), accounts for an overall positive association in the rank slope coefficient that is consistent with apparent underreaction.

3.3. How robust is the evidence of misreaction to prior good news?

As seen in Tables 2 and 3, evidence can be found for either analyst underreaction or overreaction to prior good news, depending on the statistical approach and/or prior variable on which the researcher focuses. Our goal in this section is to examine the robustness of parametric evidence of analyst overreaction and nonparametric evidence of analyst underreaction to good news.

In Panel A of Fig. 4, the most extreme prior good news decile in the case of *PrAR* does not display a tail asymmetry substantially different from the combined deciles 2–9. In contrast, in the case of *PrEC* (in Panel B) the most extreme positive decile actually exhibits the second largest degree of tail asymmetry inasmuch the combined inner decile distribution (deciles 2–9) has a considerably smaller tail asymmetry. In the case of *PrFE*, depicted in Panel C, the most extreme positive decile displays a slightly greater degree of tail asymmetry than the combined deciles 2–9. Thus, although the tail asymmetry is always present in extreme prior good news deciles, there is considerable variation in the degree of tail asymmetry across extreme good news realizations of prior news variables—a phenomenon that once again is not contemplated by general incentive and behavioral theories.

The statistical impact of variation in the degree of tail asymmetries in extreme good news deciles across prior variables is reflected in the mean forecast errors by decile presented in Fig. 5. Notably, as seen in Panel B, the relatively large tail asymmetry associated with extreme good news *PrEC* leads to a negative mean error in the 10th decile (i.e., overreaction), which aligns with the large tail asymmetry observed in Panel B of Fig. 4. In contrast, mean forecast errors for the good news *PrEC* deciles 5–9 are small and in many cases significantly positive (i.e., consistent with underreaction) because the tail asymmetry associated with these observations is small. The disproportional influence of the 10th decile of *PrEC* is also evident in regression results. In addition to being responsible for the only overall prior good news partition that produces a significant OLS slope coefficient, it is the only individual decile comprising good news for any variable that produces a significant slope coefficient (unreported in the tables). We note that removal of the 10th decile from the overall regression of forecast errors on *PrEC* leads to an increase in the slope coefficient from a value of 0.819 to 3.17, with a corresponding increase in the t-statistic. That is, the strong negative association between forecast errors and prior good news in this decile, which contributes disproportionately to the finding of overreaction to good news, also introduces severe nonlinearity in the overall regression.[20]

[20] The increasing rate of small positive errors as good news becomes more extreme contributes to positive slope coefficients in OLS regressions of forecast errors on prior good news. This is analogous to the impact of increasing rates of positive errors as bad news becomes less extreme, an effect more evident when the most extreme decile of good news is removed. The concern here, however, is that more extreme prior news leads to higher incidences of less extreme positive forecast errors—a phenomenon that is not only counterintuitive but is not predicted by extant incentive and behavioral theories of analyst inefficiency.

The most extreme good news *PrEC* decile is, therefore, largely responsible for the negative slope coefficient and the negative mean observed for good news *PrEC* partitions, suggesting the dominant influence of a small number of observations from the left tail of the distribution of forecast errors in producing parametric evidence of overreaction to good news prior earnings changes. Easterwood and Nutt (1999) refer to regression results that indicate a combination of underreaction to bad news and overreaction to good news as *generalized optimism*. From the evidence presented thus far it is clear that a small number of extreme negative forecast error observations associated with both extreme bad and extreme good news *PrEC* realizations are largely responsible for this finding. The question of the robustness of the finding of generalized optimism is magnified in the case of statistical indications of overreaction to good news because, as was reported in Table 2, good news *PrAR* and *PrFE* do not generate consistent parametric evidence of generalized optimism, even in the extreme deciles. This lends a "razor's edge" quality to the result that hinges on whether there is a sufficiently large number of extreme bad and good news realizations associated with extremely negative forecasts.[21] Furthermore, ambiguity in interpreting the evidence is introduced because there is no extant behavioral or incentive theory of analyst inefficiency that predicts that, when overreaction occurs, it will be concentrated among extreme prior news and come in the form of extreme analyst overreaction.

Finally, just as in the case of prior bad news, the presence of asymmetries also raises questions about the robustness of nonparametric evidence of analyst misreaction to prior good news. Recall from Section 3.1.1 that, in contrast to parametric statistics, nonparametric statistics suggested analyst *underreaction* to prior good news for all three prior news variables. The evidence in Tables 2 and 4 indicates that large middle asymmetries reinforce nonparametric indications of underreaction—in particular, the increasing relation between the magnitude of good news and the likelihood of small positive forecast errors, a relation that is monotonic in the case of *PrAR* and *PrFE*. Thus, the middle asymmetry, and its variation with the magnitude of prior good news, has a disproportionate impact on the inference of underreaction to good news from nonparametric statistics, including indications from medians, percentages of negative errors, and rank regressions. Notably, the percentage of positive forecast errors is substantially larger than the percentage of negative errors even in the most extreme *PrEC* decile. That is, the decile largely responsible for producing the only statistical evidence that analysts overreact to good news displays a strong tendency for errors that are consistent with underreaction.

3.4. The tail and middle asymmetries and serial correlation in analysts' forecasts

The preceding results indicate that regression evidence of underreaction is disproportionately influenced by apparent extreme underreaction to extreme bad

[21] Easterwood and Nutt (1999) eliminate the middle third of the prior earnings news distribution before estimating OLS slope coefficients, which provide the statistical support for their conclusion that analysts underreact to bad news and overreact to good news. Clearly, this test design gives even greater weight to observations that comprise the tail asymmetry.

prior news and is also impacted by the increase in the middle asymmetry as prior news improves. The asymmetries have important impacts on alternative (to regression) tests of analyst inefficiency in the literature. For example, as mentioned earlier, the analysis of the relation between current and prior forecast errors is typically not couched in terms of over- or underreaction to signed prior news, but rather in terms of overall serial correlation in lagged analyst forecast errors (see, e.g., Brown and Rozeff, 1979; Mendenhall, 1991; Abarbanell and Bernard, 1992; Ali et al., 1992; Shane and Brous, 2001; Alford and Berger, 1999). These studies focus almost exclusively on parametric measures of serial correlation and primarily on the first lag, or consecutive period errors.

Table 5 presents the Pearson and Spearman correlation between consecutive quarterly forecast errors for the overall sample and within each of the deciles of current forecast errors. The mean correlations for the entire sample are statistically significant, with yearly averages of 0.15 and 0.22, respectively. Note that the first decile, which includes the observations in the extreme left tail that are associated with the tail asymmetry, produces the greatest Pearson and Spearman correlations of 0.17 and 0.19, respectively. In contrast, the correlations in all other deciles are much smaller and most often statistically insignificant in the case of the Pearson measure. It is interesting to note that if distributions of forecast errors were symmetric, then forming deciles on the basis of current forecast errors (a procedure only followed in Table 5) would be expected to attenuate, relative to the overall sample serial correlation, the estimated correlation in every decile. However, the facts that correlation is not attenuated in the most extreme negative forecast error decile (in fact, it is larger than the overall correlation) and that the Pearson correlation is insignificant in the most extreme positive forecast error decile are additional indications of the important role the tail asymmetry plays in the findings of serial correlation. We note that when the deciles are formed based on *prior* forecast errors (that is they are sorted on the independent variable, as is done in all other tests performed in the paper) we still find that Pearson correlations are highest in the most extreme negative forecast error decile.[22]

Finally, we note that the strongest Spearman correlations in the table, other than the most extreme negative decile of current forecast errors, are found in deciles 6 and 7, i.e., those with a high concentration of current and prior small pessimistic forecast errors. The evidence is also inconsistent with what would be expected based on forming deciles on current forecast errors, where correlation in the middle deciles would be driven to zero. The higher correlations in deciles 6 and 7 are found whether deciles are formed on current or prior forecast errors. The evidence suggests the need for further exploration into the role of observations in the middle asymmetry in producing estimated serial correlation consistent with apparent analyst underreaction to their own forecast errors.

[22] It is also interesting to note from columns 4 and 5 that the first decile is not only associated with the largest mean values for current forecast errors, but is also associated with the largest mean value among the prior (i.e., lagged) forecast error deciles.

Table 5
Serial correlation in consecutive-period forecast errors

Decile ranking of forecast errors (1)	Pearson correlation in consecutive forecast errors (2)	Spearman correlation in consecutive forecast errors (3)	Mean forecast errors (4)	Mean prior quarter forecast errors (5)
Lowest	0.17#	0.19#	−2.08	−0.79
2	0.04&	0.07#	−0.44	−0.26
3	0.03	0.06#	−0.17	−0.12
4	0.06#	0.05&	−0.06	−0.04
5	0.06#	0.03&	0.00	−0.07
6	−0.01	0.09#	0.03	0.04
7	0.01	0.08#	0.08	0.04
8	−0.02	0.04&	0.15	−0.01
9	0.00	0.04&	0.29	0.02
Highest	0.00	0.04&	0.90	−0.12
Overall	0.15#	0.22#	−0.13	−0.13

This table reports the Pearson and Spearman correlation coefficients and means of current and prior quarter forecast errors *within* deciles of the ranked (current) forecast error distribution. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by beginning-of-period price.
#(&) Represents a statistically significant correlation at a 1% (5%) level.

3.5. Summary and implications of the tail and middle asymmetries on inferences of analyst efficiency

An important conclusion from the analysis of conditional forecast error distributions is that the sign of prior news variables sorts observations from the tail and middle asymmetries in a manner that (1) reinforces the inference of underreaction found in parametric statistics for all prior *bad* news partitions, an inference that is largely the result of the dominant impact of the tail asymmetry; and (2) can create offsetting or reinforcing effects that contribute to producing conflicting signs of means and regression slope coefficients within and across different prior *good* news partitions of the variables. Thus, the presence of middle and tail asymmetries in conditional distributions of forecast errors helps explain why evidence of underreaction to bad news appears to be so robust in the literature while evidence of under- and overreaction to good news is not. Attenuation of means and slope coefficients due to the relatively greater impact of the middle asymmetry in good news distributions of forecast errors also helps explain why, in every study to date that employs parametric tests and concludes that analysts' forecasts are inefficient, the magnitude of misreaction to bad news is always found to be greater than the magnitude of misreaction to good news.

It is tempting to infer from the insignificance of slope coefficients pertaining to regressions of forecast errors on prior news generated for some good news partitions reported in Table 3 and in all inner deciles of distributions of all prior news variables that, apart from cases of extreme prior news, analysts produce efficient forecasts (see, footnote 16). However, the sensitivity of statistical findings in prior good news partitions documented above suggests that we exercise caution in reaching this conclusion. Results in Fig. 4 and Table 4, along with unreported results, verify that all decile partitions of *PrAR* and *PrEC* are characterized by both middle and tail asymmetries, and that every good (bad) news decile of *PrFE* is characterized by a middle (tail) asymmetry. While it is possible that failure to reject zero slope coefficients in the inner deciles is the result of a general tendency for analyst forecasts to be efficient when prior news is not extreme, we must concede the possibility that the lower variation in the independent variable and small numbers of observations associated with tail and middle asymmetries *within deciles* combine to produce nonlinearities and lower power in a manner that obscures evidence of analyst inefficiency. That is, slicing up the data into greater numbers of partitions does not appear to eliminate the potential impact of both asymmetries in influencing inferences concerning the existence and nature of analyst inefficiency in parametric tests.[23]

The evidence in this section reveals how asymmetries can produce and potentially obscure indications of analyst inefficiency, depending on the statistical approach adopted by the researcher. Next, we describe examples of procedures that (perhaps unintentionally) mitigate the impact of observations that comprise the asymmetries, but may not necessarily shed new light on the question of whether analysts' forecasts are efficient.

3.6. Data transformations, nonlinear statistical methods, and alternative loss functions

Apart from partitioning forecast errors in parametric tests and applying nonparametric tests, some studies implicitly or explicitly adjust the underlying data in order to attenuate the disproportional impacts and nonlinearities induced by the tail asymmetry. Two such approaches are truncating and winsorizing forecast errors. As in the case of inferences concerning bias discussed in Section 2, the effects of arbitrary truncations on inferences concerning analyst under- and overreaction can be significant. Keane and Runkle (1998), for example, argue that evidence of misreaction to prior earnings news is overstated as a result of uncontrolled cross-correlation in forecast errors. However, they explicitly state that their finding of efficiency—after applying GMM to control for bias in standard errors induced by cross-correlation—rests on having first imposed a

[23] Severe heteroscedasticity in the decile regression residuals are consistent with this argument. In addition, while we do not advocate arbitrary truncations of the data to mitigate the impact of the asymmetries we find that small symmetric truncations of tail observations within decile distributions similar to those described in the previous section for the unconditional distribution of forecast errors result in significant slope coefficients in many of the inner deciles of prior returns and prior earnings changes. Because small truncations of extreme observations reduce the number of observations in each decile and further reduce variation in the independent variable, it is possible that the statistical significance of the coefficients after truncation in these cases reflects the presence of analyst inefficiency and/or the elimination of the offsetting impact of the tail asymmetry in a manner that allows the middle asymmetry to dominate an inference of inefficiency.

sample selection criterion that results in the truncation of large forecast error observations in the extreme negative tail of the distribution. Their argument for doing so is that the Compustat reported earnings used to benchmark forecasts for such observations includes large negative transitory items that analysts do not forecast. Abarbanell and Lehavy (2002) show that tail asymmetries also characterize distributions of forecast errors based on the earnings reported by commercial forecast data sources such as I/B/E/S, Zacks, and First Call, which are, in principle, free of such special items. They also report a high correlation between the observations that fall into the extreme negative tail of the distribution of forecast errors calculated with Compustat-reported earnings and those that fall into the extreme negative tail of distributions calculated with earnings provided by forecast data services. Thus, it remains to be seen whether the finding of analyst forecast rationality continues to hold when GMM procedures are applied to untruncated distributions of forecast error based on "cleaned" reported earnings numbers rather than truncated distributions of forecast errors based on Compustat earnings.[24]

An alternative to arbitrarily truncating a subset of observations is to transform the entire distribution of forecasts, a common procedure used to eliminate nonlinearities, stabilize variances, or induce a normal distribution of forecast errors to avoid violating the assumptions of the standard linear model. For example, log and power transformations mitigate skewness and the disproportionate impact of extreme observations when the dependent variable is forecast errors. However, each type of transformation alters the structure of the data in a unique way, and it is possible for different transformations to yield different inferences concerning analyst inefficiency. That is, transformations of distributions of forecast error are not likely to lead to greater consensus in the literature unless strong a priori grounds for preferring one transformation to another can be agreed upon. Such grounds can only be found by gaining a better understanding of what factors are responsible for creating relevant features of the untransformed data—an understanding that in turn would require more exacting theories than have thus far been produced as well as more institutional research into the analysts' actual forecasting task.

Finally, instead of adapting the data to fit the model the researcher may choose to adapt the model to fit the data. Disproportionate variation in the degree of tail asymmetry as a function of the sign and magnitude of prior news suggests, at a minimum, that parametric tests of analyst inefficiency should be adapted to allow for the nonlinear relationship between forecast errors and prior news. For example, after Basu and Markov (2003) replaced the quadratic assumption in their standard OLS regression with a linear loss function assuming that analysts minimize absolute forecast errors, they found little evidence to support analyst inefficiency. Imposing this loss function has an effect similar to truncating extreme observations, since such

[24] We note that although arbitrarily truncating the dependent variable (e.g., Keane and Runkle, 1998) may seem to be a more egregious form of biasing a test, the evidence presented earlier suggests that arbitrarily truncating observations in the middle of the distribution of the prior earnings news (e.g., Easterwood and Nutt, 1999) can also create problems when researchers draw inferences about the tendency for analysts to misreact to prior news, inasmuch as this procedure can further accentuate the already disproportionate impact of the tail asymmetry.

observations are given less weight in the regression (as opposed to being removed outright from the distribution).[25]

Clearly there is something to be learned from examining how inferences change under different assumed loss functions. However, at this stage in the literature, the approach will have limited benefits for a number of reasons. First, while a logical case can be made for one loss function that leads to the failure to reject unbiasedness and efficiency, an equally strong case for a loss function that leads to a rejection of unbiasedness and efficiency can also be made, without either assumption being inconsistent with existing empirical evidence of how analysts are compensated. In such cases, the conclusion about whether analyst forecasts are rational will hinge on which assumption best describes analysts' true loss function—a subject about which we know surprisingly little.[26] Second, it is possible that some errors are actually partially explained by cognitive or incentive factors that are coincidental with or are exacerbated by other factors that give rise to the same errors the researcher underweights by assuming a given loss function. Finally, although assuming a given loss function—like the choice of alternative test statistics or data truncations—may lead to a statistical inference consistent with rationality, such an approach ignores the empirical fact that the two notable asymmetries are present in the distribution. Given their influence on inferences, providing compelling reasons for these asymmetries is a prerequisite for judging whether and in what circumstances incentives or cognitive biases induce analyst forecast errors.

In the next section we take a step toward understanding how the asymmetries in forecast error distributions arise by identifying a link between the presence of observations that comprise the two asymmetries and unexpected accruals included in the reported earnings used to benchmark forecasts. This link suggest the possibility that some "errors" in the distribution of forecast errors may arise only because the forecast was inappropriately benchmarked with *reported* earnings, when in fact the analyst had targeted a different earnings number.

4. Linking bias in reported earnings to apparent bias and inefficiency in analyst forecasts

4.1. Accounting conservatism and unexpected accruals

Abarbanell and Lehavy (2003a) argue that an important factor affecting the recognition of accounting accruals is the conservative bent of GAAP. Because

[25] Note that, as discussed earlier, there may be greater difficulty detecting irrationality (alternatively, a greater likelihood of failing to reject efficiency) using regression analysis once procedures that attenuate the impact of left tail observations are introduced because the middle asymmetry is still present.

[26] The fact that the evidence of misreaction to even extreme good news is mixed for different definitions of prior news and different parametric statistics presents a challenge to adapting behavioral theories to better fit the data. Unless we can identify a common cognitive factor that explains why differences in apparent misreaction depend on the extremeness of prior news, the empirical case for any form of generalized bias or inefficiency will hinge on a relatively small number of observations comprising the tail and middle asymmetries that are not predicted by the theory.

conservative accounting principles facilitate the immediate recognition of economic losses but restrict the recognition of economic gains, the maximum amount of possible income-decreasing accruals that a typical firm can recognize in a given accounting period will be larger than the maximum amount of income-increasing accruals (see, e.g., Watts, 2003). Table 6 provides evidence that supports this intuition.

The table presents selected summary statistics associated with cross-sectional distributions of firms' quarterly unexpected accruals over the sample period.[27] The mean unexpected accrual over the sample period is −0.217. While the distribution is negatively skewed, the median is 0.023 and the percentage of positive and negative unexpected accruals is nearly equal. It is evident from Table 6 that, while the unexpected accrual distribution is relatively symmetric in the middle, it is characterized by a longer negative than positive tail. For example, the magnitude of the average values at the 25th and 75th percentiles is nearly identical. However, symmetric counterpart percentiles outside these values begin to diverge by relatively large amounts, beginning with a comparison of the values at the 10th and 90th percentiles. The differences become progressively larger with comparisons of counterpart percentiles farther out in the tails. For example, the average 5th and 3rd percentile values are approximately 1.17 times larger than the average 95th and 97th percentiles, and the average value of the 1st percentile is 1.30 times larger than the average value of the 99th percentile. We stress that, although the percentile values of unexpected accruals vary from quarter to quarter, the basic shape of the distribution is similar in every quarter.

4.2. *Linking unexpected accruals to asymmetry in tails of forecast error distributions*

The measure of unexpected accruals we employ is based on historical relations known prior to the quarter for which earnings are forecast. Although the term "unexpected" is used, it is possible—in fact likely—that analysts will acquire new information about changes in the relations between sales and accruals that occurred during the quarter before they issue their last forecast for a quarter. Nevertheless, we can use the measure of unexpected accruals to identify, ex-post, cases in which significant changes in accrual relations did take place, and then assess whether the evidence is consistent with analysts' issuing a final forecast of earnings for the quarter either unaware of some of these changes or unmotivated to forecast them.

If analysts' forecasts do not account for the fact that some firms will recognize accruals placing them in the extreme negative tails of the distribution of unexpected accruals, then there will be a direct link between the negative tail of this distribution and the extreme negative tail of the forecast error distribution. The conjectured link

[27] Unexpected accruals reported in the tables are the measure produced by the modified Jones model applied to quarterly data (see Appendix A for calculations). To facilitate comparison with our forecast error measure, we express unexpected accruals on a per share basis scaled by price and multiplied by 100. As indicated earlier, the qualitative results are unaltered when we employ the unmodified Jones model and other estimation techniques found in the literature, including one that excludes nonrecurring and special items.

Table 6
Descriptive statistics on quarterly distributions of unexpected accrual, 1985–1998

Unexpected accrual	
Number of observations	33,548
Mean	−0.217
Median	0.023
Standard deviation	5.600
Skewness	−1.399
Kurtosis	16.454
% Positive	50.8
% Negative	49.2
% Zero	0.0
P1	−20.820
P3	−11.547
P5	−8.386
P10	−4.574
P25	−1.349
P75	1.350
P90	4.185
P95	7.148
P97	9.891
P99	15.945

This table reports descriptive statistics on quarterly distributions of unexpected accruals. Unexpected accruals are calculated using the modified Jones model as described in the appendix (expressed as unexpected accrual per share scaled by price and multiplied by 100).

is depicted in Fig. 6. The figure shows mean forecast errors in intervals of (+/−) 0.5% centered on the percentiles of unexpected accruals. For example, the mean forecast error corresponding to the Xth percentile of unexpected accruals is computed using observations that fall in the interval of $X-0.5$ to $X+0.5$ percentiles of the unexpected accruals distribution.

It is clear from Fig. 6 that extreme negative forecast errors are associated with extreme negative unexpected accruals. That is, the evidence suggests a direct connection between the tail asymmetry in the forecast error distribution (documented in earlier sections) and an asymmetry in tails of the unexpected accrual measure.[28] This link continues to be observed even when we employ consensus earnings estimates and reported earnings that are, in principle, stripped of

[28] Another example of this link relates to the evidence on serial correlation in forecast errors presented earlier. Recall from Table 5 that the most extreme prior forecast error decile is also associated with the most negative mean current forecast errors. In unreported results we find that this decile is also characterized by the largest negative lagged and current unexpected accruals observed for these deciles (whether forecast error deciles are formed on the current or prior forecast errors). Thus, consecutive quarters of large, negative unexpected accruals go hand-in-hand with consecutive quarters of extreme negative forecast error observations that, in turn, are associated with high levels of estimated serial correlation.

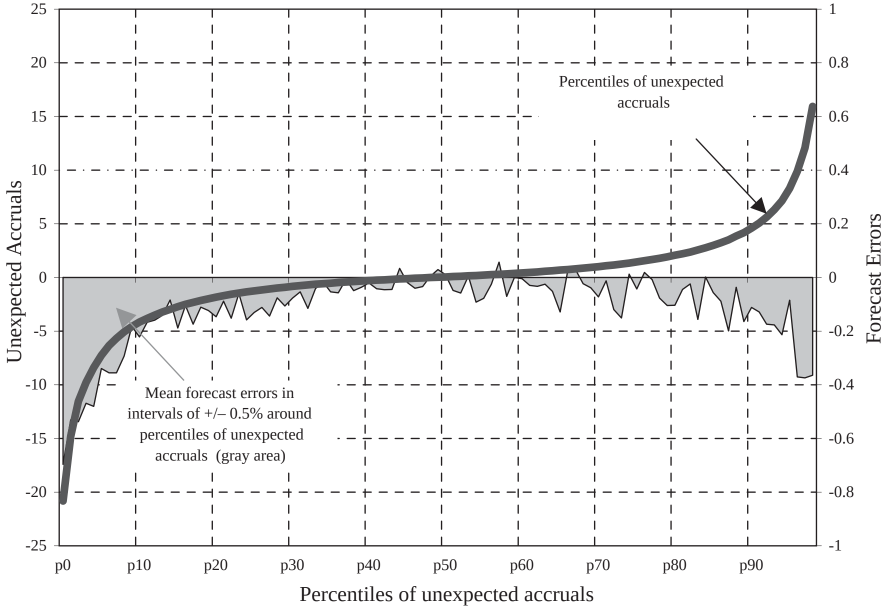

Fig. 6. Linking unexpected accruals and the asymmetry in tails of forecast error distributions. This figure depicts percentiles of unexpected accruals and mean forecast errors (gray area) in intervals of (+/−) 0.5% around unexpected accruals percentiles. For example, the mean forecast errors corresponding to the Xth percentile of unexpected accruals is computed using observations that fall in the interval of $X-0.5$ to $X+0.5$ percentiles of the unexpected accruals distribution. Forecast error equals reported earnings minus consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Unexpected accruals are the measure produced by the modified Jones model as described in the appendix (expressed as percentage of unexpected accrual per share scaled by price and multiplied by 100).

nonrecurring items and special charges (because Zacks indicates that analysts do not attempt to forecast these items), and a measure of unexpected accruals that also strips such items (see, Hribar and Collins, 2002). This suggests that an association exists between extreme negative accruals deemed ‘‘special or nonrecurring’’ and extreme negative accruals that do not fit this description. One possible reason for this association is that firms take an ‘‘unforecasted earnings bath,’’ recognizing operating expenses larger than justified by the firm’s actual performance for the period at the same time as they recognize large discretionary or nondiscretionary negative transitory operating and nonoperating items (see, Abarbanell and Lehavy, 2003b).

A second explanation for the association between large negative unexpected accruals and large negative forecast errors is that all the models of unexpected accruals examined in this study are prone to misclassifying nondiscretionary accruals as discretionary in periods when firms are recognizing large, negative transitory items. Combining the misclassification argument with a cognitive based argument that analysts react too slowly to extreme current performance would account for the observed link between unexpected accruals and forecast errors. While a more detailed analysis is beyond the scope of this paper, the evidence in Fig. 6 sheds additional light on the question of misclassification. It is seen in the figure that the largest percentiles of *positive* unexpected accruals are actually associated with fairly large negative mean forecast errors. The upside down U-shape that characterizes mean forecast errors over the range of unexpected accruals is inconsistent with a straightforward misclassification argument.[29] This is because if extreme positive unexpected accruals reflected misclassification in the case of firms that experience strong current performance, these would be the same cases in which analysts' forecasts would tend to underreact to extreme current good news and issue forecasts that fall short of reported earnings. The association between firm recognition of large negative transitory items and large negative operating items and the association between forecast errors and unexpected accruals are empirical phenomena that clearly deserve further exploration.

4.3. Linking unexpected accruals and the asymmetry in the middle of forecast error distributions

Table 7 provides evidence suggesting that unexpected accruals are also associated with the middle asymmetry in forecast error distributions. Column 2 presents a comparison of the ratio of positive to negative errors in narrow intervals centered on a zero forecast error (as reported in Panel B of Table 1) to the analogous ratio when forecast errors are based on reported earnings after "backing out" the realization of unexpected accruals for the quarter. In sharp contrast to the results reported in Table 1, the results in Table 7 indicate that after controlling for unexpected accruals, the number of small positive forecast errors *never* exceeds the number of small negative forecast errors in any interval. For example, the ratio of good to bad earnings surprises in the interval between [−0.1, 0) and (0, 0.1] is 1.63 (a value reliably different from 1) when errors are computed using earnings as reported by the firm, compared to 0.95 (statistically indistinguishable from 1) when errors are based on reported earnings adjusted for unexpected accruals. Thus, as in the case of the tail asymmetry, there is an empirical link between firms' recognition of unexpected accruals and the middle asymmetry. Given the impact of the tail and middle asymmetries on inferences concerning analyst bias and inefficiency described in Sections 2 and 3, researchers should take into account the role of unexpected accruals in the reported earnings typically used to benchmark forecast.

[29] The plot of *median* forecast errors around unexpected accrual percentiles also displays an upside down U-shape. However, as one might expect from the summary statistics describing the forecast error distributions in Table 1, the magnitude of these median errors is much smaller than mean errors, and large negative median forecast errors are only found in the most extreme positive and negative unexpected accrual percentiles.

Table 7
Linking unexpected accruals and the asymmetry in the middle of forecast error distributions

Range of forecast errors (1)	Ratio of positive to negative forecast errors based on *reported* earnings (2)	Ratio of positive to negative forecast errors based on earnings adjusted for unexpected accruals (3)
Overall	1.19*	0.96*
[−0.1, 0) & (0, 0.1]	1.63*	0.95
[−0.2, −0.1) & (0.1, 0.2]	1.54*	0.97
[−0.3, −0.2) & (0.2, 0.3]	1.31*	1.09
[−0.4, −0.3) & (0.3, 0.4]	1.22*	0.97
[−0.5, −0.4) & (0.4, 0.5]	1.00	0.99
[−1, −0.5) & (0.5, 1]	0.83*	0.95*
[Min, −1) & (1, Max]	0.40*	0.95*

This table provides the ratio of positive to negative forecast errors for observations that fall into increasingly larger and nonoverlapping symmetric intervals moving out from zero forecast errors. For example, the forecast error range of [−0.1, 0) & (0, 0.1] includes all observations that are greater than or equal to −0.1 and (strictly) less than zero and observations that are greater than zero and less than or equal to 0.1. Forecast error is reported earnings minus the last consensus forecast of quarterly earnings issued prior to earnings announcement scaled by the beginning-of-period price. Earnings before unexpected accruals (used to compute the forecast error ratios in column 3) are calculated as the difference between reported earnings and the empirical measure of unexpected accruals.
*A test of the difference in the frequency of positive to negative forecast errors is statistically significant at or below a 1% level.

4.4. *Explanations for a link between asymmetries in forecast error distributions and unexpected accruals*

One general explanation for the link between unexpected accruals and the presence of asymmetries in forecast error distributions is that incentive or judgment factors that affect analysts' forecasts are exacerbated when estimates of unexpected accruals are likely to be unusual. For example, it is possible that cases of underreaction that appear to be concentrated among firms with the most extreme bad news reflect situations in which analysts have the weakest (strongest) incentives to lower (inflate) forecasts or suffer from cognitive obstacles that prevent them from revising their forecasts downward. At the same time, it has been argued in the accounting literature that unexpected accrual models produce biased downward estimates in exactly the same circumstances, i.e., when firms are experiencing extremely poor performance (see, e.g., Dechow et al., 1995).[30] This combination of

[30] The controversy over bias in unexpected accrual estimates relates to the issue of whether they truly reflect the exercise of discretion on the part of management. The conclusion that such measures are flawed is generally based on results from misclassification tests in which the maintained assumption is that historical data have not been affected by earnings management. This assumption can be challenged on logical grounds and, somewhat circularly, on the grounds that no evidence in the empirical literature supports this assumption.

potentially unrelated factors could account for the fact that extreme negative unexpected accruals accompany analysts' final forecasts for quarters characterized by prior bad news. Analogously, a higher incidence of small positive versus small negative errors as news improves is consistent with a greater likelihood of a *fixed* amount of judgment-related underreaction or incentive-based inflation of forecasts the better the prior news. The fact that unexpected accruals also appear to be related to the presence of the middle asymmetry may be coincidental to a slight tendency for unexpected accrual estimates to be positive in cases of firms experiencing high growth and positive returns (see, e.g., McNichols, 2000).[31]

Clearly there is a long list of possible combinations of unrelated factors that can simultaneously give rise to the two asymmetries in forecast error distributions and their apparent link to unusual unexpected accruals, which makes it difficult to pinpoint their source. Nevertheless, researchers still have good reason to consider these empirical facts when developing empirical test designs, choosing test statistics, and formulating and refining analytical models. One important reason is that if analysts' incentives or errors in judgment are responsible for systematic errors, it should be recognized that these factors appear to frequently produce very specific kinds of errors; i.e., small positive and extreme negative errors. To date, however, individual incentive and cognitive-based theories do not identify the economic conditions, such as extreme good and bad prior performance, that would be more likely to trigger or exacerbate incentive or judgment issues in a manner leading to exactly these types of errors. These explanations are also not easily reconciled with an apparent schizophrenia displayed by analysts who tend to slightly underreact to extreme good prior news with great regularity, but overreact extremely in a limited number of extreme good news cases. Finally, current behavioral and incentive-based theories do not account for actions undertaken by *firms* that produce reported earnings associated with forecast errors of the type found in the tail and middle asymmetries. Until such theories begin to address these issues it is not clear how observations that fall into the observed asymmetries should be treated in statistical tests of general forms of analyst irrationality. The identification of specific types of influential errors and their link to unexpected accruals documented in this paper provides a basis or expanding and refining behavioral and incentive theories of forecast errors.

A second reason for focusing on the empirical properties of forecast error distributions and their link to unexpected accruals is because it supports an alternative perspective on the cause of apparent forecast errors; i.e., the possibility that analysts either lack the ability or motivation to forecast discretionary biases in reported earnings. If so, then earnings manipulations undertaken to beat forecasts or to create reserves (e.g., earnings baths) that *are not* anticipated in analysts' forecasts

[31] McNichols (2000) argues that a positive association between unexpected accruals and growth reflects a bias in unexpected accrual models, but she does not perform tests to distinguish between this hypothesis and the alternative that high-growth firms are more likely to recognize a positive discretionary accrual to meet an earnings target, as argued in Abarbanell and Lehavy (2003a). We note that the presence of the middle asymmetry among firms with prior bad news returns and earnings changes is inconsistent with the misclassification argument.

may in part account for concentrations of small positive and large negative observations in distributions of forecast errors.[32] This suggests that evidence previously inferred to indicate systematic errors in analysts' forecasts might actually reflect the inappropriate benchmarking of forecasts.[33] An important implication of this possibility is that researchers may be formulating and testing new incentive and cognitive theories or turning to more advanced statistical methods and data transformations in order to explain forecast errors that are apparent, not real.

5. Summary and conclusions

In this paper we reexamine the evidence in the literature on analyst-forecast rationality and incentives and assess the extent to which extant theories for analysts' forecast errors are supported by the accumulated empirical evidence. We identify two relatively small asymmetries in cross-sectional distributions of forecast error observations and demonstrate the important role they play in generating statistical results that lack robustness or lead to conflicting conclusions concerning the existence and nature of analyst bias and inefficiency with respect to prior news. We describe how inferences in the literature have been affected, but these examples by no means enumerate all of the potential problems faced by the researcher using earnings surprise data. Our examples do demonstrate how some widely held beliefs about analysts' proclivity to commit systematic errors (e.g., the common belief that analysts generally produce optimistic forecasts) are not well supported by a broader analysis of the distribution of forecast errors. After four decades of research on the rationality of analysts' forecasts it is somewhat disconcerting that the most definitive statements observers and critics of earnings forecasters appear willing to agree on are ones for which there is only tenuous empirical support.

We stress that the evidence presented in this paper is not inconsistent with forecast errors due to analysts' errors in judgment and/or the effects of incentives. However, it does suggest that refinements to extant incentive and cognitive-based theories of systematic errors in analysts' forecasts may be necessary to account for the *joint* existence of both a tail asymmetry and a middle asymmetry in cross-sectional

[32] Abarbanell and Lehavy (2003b) offer theoretical, empirical, and anecdotal support for the assumption that analysts may not be motivated to account for or capable of anticipating earnings management in their forecasts. Based on this assumption they develop a framework in which analysts always forecast unmanaged earnings and firms undertake extreme income-decreasing actions or manipulations that leave reported earnings slightly above outstanding forecasts to inform investors of their private information. They describe a setting in which neither analysts nor managers behave opportunistically and investors are rational, where the two documented asymmetries in forecast error distributions arise and are foreshadowed by the sign and magnitude of stock returns before the announcement of earnings. In their setting, prior news predicts biases in the reported earnings benchmark, not biases in analysts' forecasts.

[33] Gu and Wu (2003) offer a variation on this argument suggesting that the analysts forecast the median earnings of the firm's ex-ante distribution, which also suggests that for some firms ultimate reported earnings (reports that differ from median earnings) are not the correct benchmark to use to assess whether analysts' forecasts are biased.

distributions of forecast errors. At the very least, researchers attempting to assess the descriptiveness of such theories should be mindful of the disproportionate impact of relatively small numbers of observations in the cross-section on statistical inferences.[34]

The evidence we present also highlights an empirical link between unexpected accruals embedded in the reported earnings benchmark to forecasts and the presence of the tail and middle asymmetries in forecast error distributions. Such biases in reported earnings benchmarks may point the way toward expanding and refining incentive and cognitive-based theories of analyst errors in the future. However, these results also raise questions about whether analysts are expected or motivated to forecast discretionary manipulations of reported earnings by firms. Thus, these results also highlight the fact that research to clarify the true target at which analyst forecasts are aimed is a prerequisite to making a compelling case for or against analyst rationality. Organizing our thinking around the salient properties of forecast error distributions and how they arise has the potential to improve the chaotic state of our current understanding of analyst forecasting and the errors analysts may or may not systematically commit.

Appendix A. The calculation of unexpected accruals

Our proxy for firms' earnings management, quarterly unexpected accruals, is calculated using the modified Jones (1991) model (Dechow et al., 1995); see Weiss (1999) and Han and Wang (1998) for recent applications of the Jones model to estimate quarterly unexpected accruals. All required data (as well as earnings realizations) are taken from the 1999 Compustat Industrial, Full Coverage, and Research files.

According to this model, unexpected accruals (scaled by lagged total assets) equal the difference between the predicted value of the scaled expected accruals ($NDAP$) and scaled total accruals (TA). Total accruals are defined as

$$TA_t = (\Delta CA_t - \Delta CL_t - \Delta Cash_t + \Delta STD_t - DEP_t)/A_{t-1},$$

where ΔCA_t is the change in current assets between current and prior quarter, ΔCL_t the change in current liabilities between current and prior quarter, $\Delta Cash_t$ the change in cash and cash equivalents between current and prior quarter, ΔSTD_t the change in debt included in current liabilities between current and prior quarter, DEP_t the current-quarter depreciation and amortization expense, and A_t the total assets.

[34] For example, given the recent attention in the literature to incentive factors that give rise to small, apparently pessimistic forecast errors (see footnote 5), it is important that researchers testing general behavioral theories understand that the middle asymmetry has the ability to produce evidence consistent with cognitive failures or, potentially, to obscure it. Similarly, the tail asymmetry has played a role in producing both parametric and nonparametric evidence that supports incentive-based theories of bias and inefficiency. However, such theories identify no role for extreme news or extreme forecast errors in generating predictions and do not acknowledge or recognize their crucial role in providing support for hypotheses.

The predicted value of expected accruals is calculated as

$$NDAP_t = \alpha_1(1/A_{t-1}) + \alpha_2(\Delta REV_t - \Delta REC_t) + \alpha_3 PPE_t,$$

where ΔREV_t is the change in revenues between current and prior quarter scaled by prior quarter total assets, ΔREC_t the change in net receivables between current and prior quarter scaled by prior quarter total assets, and PPE_t the gross property plant and equipment scaled by prior quarter total assets.

We estimate the firm-specific parameters, α_1, α_2, and α_3, from the following regression using firms that have at least ten quarters of data:

$$TA_{t-1} = a_1(1/A_{t-2}) + a_2\Delta REV_{t-1} + a_3 PPE_{t-1} + \varepsilon_{t-1}.$$

The modified Jones model resulted in 35,535 firm-quarter measures of quarterly unexpected accruals with available forecast errors on the Zacks database.

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Analyst Conflicts and Research Quality*

Anup Agrawal
University of Alabama

Mark A. Chen
Georgia State University

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*Agrawal: Culverhouse College of Business, Tuscaloosa, AL 35487-0224, Tel: (205) 348-8970, aagrawal@cba.ua.edu, http://www.cba.ua.edu/personnel/AnupAgrawal.html. Chen: Robinson College of Business, Department of Finance, Atlanta, GA 30303-3083, Tel: (404) 413-7339, machen@gsu.edu. We thank Dan Bernhardt, Utpal Bhattacharya, Jonathan Clarke, Doug Cook, Rob Hansen, Paul Irvine, Jeff Jaffe, Prem Jain, Chuck Knoeber, Junsoo Lee, Kai Li, Felicia Marston, Erik Peek, Gordon Phillips, Mike Rebello, David Reeb, Jay Ritter, seminar participants at Indiana University, Tulane University, University of Alabama, University of New Orleans, the 2004 EFA-Maastricht meetings, the 2005 AFA meetings, and the 2006 ALEA-UC Berkeley meetings for helpful comments and suggestions. Special thanks are due to Fernando Zapatero, the editor. We also thank Thomson Financial for providing analyst forecast data via the Institutional Brokers Estimates System (I/B/E/S). Agrawal acknowledges financial support from the William A. Powell, Jr. Chair in Finance and Banking.

Analyst Conflicts and Research Quality

Abstract

This paper examines whether the quality of stock analysts' forecasts is related to conflicts of interest from their employers' investment banking (IB) and brokerage businesses. We consider four aspects of forecast quality: accuracy, bias, and revision frequency of quarterly earnings per share (EPS) forecasts and relative optimism in long-term earnings growth (LTG) forecasts. Using a unique dataset that contains the annual revenue breakdown of analysts' employers among IB, brokerage, and other businesses, we uncover two main findings. First, accuracy and bias in quarterly EPS forecasts appear to be unrelated to conflict magnitudes, after controlling for forecast age, firm resources and analyst characteristics. Second, relative optimism in LTG forecasts and the revision frequency of quarterly EPS forecasts are positively related to the importance of brokerage business to analysts' employers. Additional tests suggest that the frequency of quarterly forecast revisions is positively related to analysts' trade generation incentives. Our findings suggest that reputation concerns keep analysts honest with respect to short-term earnings forecasts but not long-term growth forecasts. In addition, conflicts from brokerage appear to play a more important role in shaping analysts' forecasting behavior than has been previously recognized.

Keywords: Stock analysts, Security analysts, Analyst conflicts, Analyst forecasts, Investment banking, Brokerage commissions, Conflicts of interest

JEL Classifications: G24, G28, G34, G38, K22, M41

Analyst Conflicts and Research Quality

1. Introduction

In April 2003, ten of the largest Wall Street firms reached a landmark settlement with the New York State Attorney General, the U.S. Securities and Exchange Commission (SEC), and other federal and state securities regulators on the issue of conflicts of interest faced by sell-side analysts. The firms agreed to pay a record $1.4 billion in penalties to settle government charges that their analysts had routinely issued optimistic stock research in order to win investment banking (IB) business from the companies they covered. Regulators cited the behavior of analysts such as Jack Grubman, perhaps the most influential telecom stock analyst during the late 1990s stock market boom. In November 1999, Grubman, then an analyst with Salomon Smith Barney, raised his rating on AT&T stock from a 'hold' to a 'strong buy' in an apparent bid to court AT&T's large IB business (see Gasparino (2002)).[1]

The settlement forced the participating securities firms to make structural changes in the production and dissemination of equity research (see Smith, Craig and Solomon (2003)). For example, analysts are no longer allowed to accompany investment bankers in making sales presentations, and securities firms are required to maintain separate reporting and supervisory structures for their research and IB operations. Firms must tie an analyst's pay to the quality and accuracy of his research rather than to the amount of IB business the research generates. In addition, an analyst's written report on a company must disclose whether his firm conducts IB business with the researched company.[2] Of the total settlement amount, $430 million is earmarked for providing investors with stock research from independent research firms.

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[1]Other instances of alleged conflicts of interest were commonplace. One example involved Phua Young, a Merrill Lynch analyst who followed Tyco International, Ltd. Merrill reportedly hired Young in September 1999 at the suggestion of Dennis Kozlowski, Tyco's then-CEO. Whereas the previous Merrill analyst had been highly critical of Tyco, Young embraced his role as a cheerleader for the company. See Maremont and Bray (2004).

[2]Throughout the paper, we refer to an analyst's employer as a 'firm' and a company followed by an analyst as a 'company'.

The settlement was fundamentally grounded on the premise that analysts who are free from potential conflicts of interest produce superior, unbiased stock research. In this paper, we provide empirical evidence on whether the quality of analysts' research is related to the magnitude of their conflicts of interest. We focus on an important product of analyst research: forecasts of corporate earnings per share (EPS) and earnings growth. We address four questions. First, how is the accuracy of analysts' quarterly EPS forecasts related to the magnitude of conflicts with IB or brokerage business? Second, are conflicts related to the bias in quarterly forecasts? Third, how are conflicts related to the revision frequency of quarterly forecasts? And finally, what is the relation between analyst conflicts and the relative optimism in long-term earnings growth (LTG) forecasts?

Answers to these questions are important not only to regulators and academics, but also to a broad range of stock market participants. Retail and institutional investors alike use analyst reports to form expectations about the future prospects of a company. In fact, institutional investors seem to rely so much on analysts' opinions that they generally avoid investing in stocks without analyst coverage (see, e.g., O'Brien and Bhushan (1990)). Prior academic studies have found that analysts' earnings forecasts and stock recommendations have investment value (see, e.g., Givoly and Lakonishok (1979), Stickel (1991), Womack (1996), Barber, Lehavy, McNichols and Trueman (2001), Jegadeesh, Kim, Krische and Lee (2004), and Loh and Mian (2006)). Moreover, analysts are widely quoted in the news media on major corporate events, and their pronouncements on television can lead stock prices to respond within seconds (see Busse and Green (2002)).

To conduct our empirical analysis, we assemble a unique dataset that contains the revenue breakdown for analyst employers (most of which are private firms not subject to the usual disclosure requirements for publicly-traded companies) into revenues from IB, brokerage, and other businesses. This information allows us to examine in detail the relation between the quality of analyst research and potential conflicts arising from IB and brokerage businesses. We perform univariate and panel regression analyses using a sample of more than 170,000 quarterly EPS forecasts and more than 38,000 LTG forecasts for about 7,400 U.S. public companies during the January 1994 to March 2003 time period. These forecasts were issued by about 3,000 analysts employed by 39 publicly-traded securities firms and 124 private securities firms.

Prior academic research has focused on conflicts faced by analysts in the context of pre-existing underwriting relationships.[3] For instance, Lin and McNichols (1998) and Michaely and Womack (1999) find that analysts employed by underwriters in security offerings tend to be more optimistic than other analysts about the prospects of the issuing company. Kadan, Madureira, Wang, and Zach (2009) document that recommendations of analysts whose employers have underwriting relationships with the covered companies are less optimistic and more informative following the enactment of recent U.S. conflict-of-interest regulations. Our paper contributes to this line of research in several ways. First, our approach takes into account both actual as well as potential conflicts from IB activities. As long as an analyst's employer has an IB business, even if the employer does not *currently* do business with the followed company, it might aspire to do so in the future. Second, we examine the conflict of interest arising from IB in general, rather than solely from security offerings. In addition to offering underwriting services, an investment bank can offer advisory services on mergers and corporate restructuring. Third, while prior academic research, the news media, and regulators have generally focused on conflicts from IB business, our data allow us to examine conflicts from brokerage business as well. As discussed in Section 2 below, IB and brokerage operations are two distinct sources of potential conflicts of interest, and they may influence analyst behavior in different ways.

Fourth, the prior empirical finding that underwriter analysts tend to be more optimistic than other analysts is consistent with two alternative interpretations: (a) underwriter analysts issue optimistic reports on companies to reward them for past IB business or to curry favor to win future IB business, and (b) companies select underwriters whose analysts already have favorable views of their stocks to begin with. The second interpretation recognizes that underwriter choice is endogenous and that underwriter analyst optimism by itself does not necessarily imply a conflict of interest. We sidestep this issue of endogeneity by broadening the focus beyond the existence of

[3] See Ramnath, Rock, and Shane (2006) and Mehran and Stulz (2007) for excellent reviews of the literature on analyst conflicts.

underwriting relations between analyst employers and followed companies. Specifically, we capture the overall importance of IB and brokerage businesses to analyst employers by measuring the percentages of total annual revenues derived from these businesses. Unlike measures based on underwriting relations between analysts' employers and followed companies, the percentages of total revenues from IB or brokerage businesses are arguably exogenous in that they would be largely unaffected by an individual analyst's forecasting behavior. Finally, our approach yields substantially larger sample sizes than those used in prior research, leading to greater statistical reliability of the results.

Several papers study analyst conflicts using methods that are somewhat related to our approach. For example, Barber, Lehavy, and Trueman (2007) find that recommendation upgrades (downgrades) by brokerage houses that have IB business under-perform (outperform) similar recommendations by non-IB brokerages and independent research firms. Cowen, Groysberg and Healy (2006) find that full-service securities firms, which have both IB and brokerage businesses, issue less optimistic forecasts and recommendations than do non-IB brokerage houses. Finally, Jacob, Rock and Weber (2008) find that short-term earnings forecasts made by investment bank analysts are more accurate and less optimistic than those made by analysts at independent research firms. We extend this line of research by quantifying the reliance of a securities firm on IB and brokerage businesses. This is an important feature of our paper for at least two reasons. First, given that many securities firms operate in multiple lines of business, it can be difficult to unambiguously classify them according to business lines. By separately measuring the magnitudes of both IB and brokerage conflicts in each firm, our approach avoids the need to rely on a classification scheme. Second, since the focus of this research is on the consequences of analysts' conflicts, measuring the magnitude of conflict, and not simply its existence, is important. Our conclusions sometimes differ from classification-based studies.

Our main findings can be summarized as follows. We find no evidence that the accuracy or bias in individual analysts' quarterly EPS forecasts is related to the magnitude of their IB or brokerage conflicts, after controlling for forecast age, firm resources, analyst experience and analyst workloads. This result also holds for technology stocks and during the late-1990s stock market boom, settings in which analysts may have faced particularly severe conflicts. The result holds for both publicly-traded and private analyst employers, and it is robust to the use of alternate measures of conflict magnitude. However, we find that the importance of brokerage conflicts is positively related to both the level of LTG forecasts and the revision frequency of quarterly EPS forecasts. In further tests, we find that greater brokerage conflicts make it less likely that forecast revisions are intended to provide investors with timely and accurate information. That is, trade-generation motives appear to drive forecast revisions to a greater degree as brokerage conflicts increase.

Our findings provide two important insights into the forecasting behavior of analysts who face potential conflicts of interest. First, while analysts do not appear to systematically respond to conflicts by biasing short-term (quarterly EPS) forecasts, they do appear to succumb to conflicts when making long-term earnings growth forecasts. This difference may be because analysts are more concerned about a possible loss of reputation from issuing easily-refuted short-term forecasts than from issuing long-term growth forecasts. Second, despite obvious instances of abuse that have been reported in the media, we find no systematic relationship between the magnitude of IB conflicts and several aspects of analysts' forecasting behavior. Brokerage conflicts, on the other hand, appear to play a more important role in shaping analysts' forecasting behavior than has been previously recognized.[4]

The remainder of the paper is organized as follows. Section 2 discusses the potential effects of conflicts of interest on analyst forecasts. Section 3 describes our sample and data. Section 4 presents our main empirical results. Section 5 examines two alternative explanations of our results on forecast revision frequency. Section 6 presents

[4] In a companion paper (Agrawal and Chen (2008)), we find that analysts with greater IB and brokerage conflicts issue more positive stock recommendations, particularly during the late-1990s stock bubble. But the reactions of stock prices and trading volumes to recommendation revisions suggest that investors adjust for these biases by discounting the opinions of more conflicted analysts, even during the bubble. Furthermore, the one-year investment performance of recommendation revisions is unrelated to conflict magnitudes, suggesting that the marginal investor is not systematically misled by analyst advice. In related research, Malmendier and Shanthikumar (2007) show that while small investors appear to naively follow optimistic recommendations by underwriter analysts, institutions appear to rationally discount recommendations for underwriting bias.

additional results from two partitions of the sample: the technology sector versus other industry sectors; and the late 1990s versus other time periods. Section 7 concludes.

2. Potential effects of conflicts of interest

This section discusses the potential effects of conflicts of interest on four aspects of analysts' behavior and performance: accuracy, bias, and revision frequency of quarterly EPS forecasts, and optimism in long-term earnings growth projections. Section 2.1 deals with IB conflicts, and Section 2.2 deals with brokerage conflicts.

2.1 Investment banking conflicts

The most widely-discussed type of analyst conflict arises from the fact that securities firms can use optimistic research to try to win or keep lucrative underwriting business.[5] Several academic studies have reported evidence of analyst optimism in the context of existing underwriting relationships. For example, Dugar and Nathan (1995) and Lin and McNichols (1998) find that analysts whose employers have underwritten seasoned equity offerings issue more favorable earnings forecasts and stock recommendations about clients than do non-underwriter analysts. Dechow, Hutton, and Sloan (2000) document a positive bias in underwriter analysts' long-term growth (LTG) forecasts for firms conducting seasoned equity offerings. Michaely and Womack (1999) find that underwriter analysts in initial public offerings are generally more optimistic in recommending a client firm's stock than are non-underwriter analysts, but underwriter recommendations exhibit particularly poor long-run stock performance. And O'Brien, McNichols and Lin (2005) find that underwriter analysts in equity offerings are slower to downgrade stocks - but faster to upgrade them - than non-underwriter analysts.

Securities firms seek not only to maintain the goodwill of existing IB clients, but also to attract new corporate clients. Corporate managers may award underwriting or merger advisory mandates to securities firms that issue consistently optimistic earnings forecasts. This incentive implies that EPS forecasts of analysts subject to pressure from

[5]Ljungqvist, Marston and Wilhelm (2006, 2009) find that while optimistic recommendations do not help the analyst's firm win the lead underwriter or co-manager positions in general, they do help the firm win the co-manager position in deals where the lead underwriter is a commercial bank.

IB should exhibit a positive bias relative to forecasts of analysts at independent firms. Likewise, the long-term (three to five year) earnings growth estimates of analysts at IB firms should be rosier than the growth projections of independent analysts.

Alternatively, pressure from IB business can lead to a *pessimistic* bias in analyst forecasts. A widely-held belief among market participants is that corporations often seek to meet or beat analysts' quarterly estimates, regardless of the absolute level of performance. Whether or not a company meets its quarterly estimates can serve as a rule of thumb by which boards of directors and investors evaluate managers (see, e.g., Degeorge, Patel, and Zeckhauser (1999) and Farrell and Whidbee (2003)). Indeed, Bartov, Givoly, and Hayn (2002) find that companies that exceed the threshold set by analyst estimates subsequently experience higher abnormal stock returns. Chan, Karceski, and Lakonishok (2007) document that the frequency of non-negative earnings surprises has grown in recent years, particularly for growth firms and for analysts employed by firms with no IB business. Therefore, 'lowering the bar' with pessimistic forecasts, especially near the earnings announcement date, may be a way for conflicted analysts to win favor with potential IB clients.

If optimistic or pessimistic forecast biases are important, then, *ceteris paribus*, the overall accuracy of conflicted analysts should be lower than that of independent analysts. However, there are at least three mitigating forces that can reduce bias among analysts at large investment banks. First, compared to an independent research firm, an investment bank may provide an analyst with an environment that is more conducive to making high-quality forecasts. Possible advantages include access to greater resources and research support (Clement (1999)) and to information generated by the underwriting and due diligence process (Michaely and Womack (1999)). Second, firms with large IB operations can attract analysts with better forecasting ability. As Hong and Kubik (2003) find, more accurate analysts tend to move to more prestigious securities firms, which are more likely than small, regional firms to have significant IB operations.

Finally, reputation concerns can reduce analysts' response to IB conflicts. As in the model of Bolton, Freixas, and Shapiro (2007), financial intermediaries that provide misleading advice to investors can suffer a loss of market share in the presence of competition from other information providers. Indeed, empirical evidence suggests that optimism in lead underwriters' stock recommendations is mitigated when a larger number of unaffiliated analysts cover the same stock (see Sette (2011)). It therefore stands to reason that an analyst who wants to avoid the risk of a tarnished reputation or loss of career prospects will be less inclined to issue biased and misleading earnings forecasts. Overall, then, the effect of IB conflicts on EPS and LTG forecasting behavior can be expected to depend on multiple and sometimes opposing forces. It is the net effect of these forces that we seek to understand in our empirical analysis below.

2.2 Brokerage conflicts

When a securities firm has significant brokerage operations, its analysts face direct or indirect incentives to use their research to generate trading commissions.[6] For example, an analyst may be able to increase his firm's trading volume by issuing optimistic projections.[7] A new earnings forecast that is particularly positive should lead to trading by both new investors and current shareholders, provided that investors ascribe at least some information content to the forecast. On the other hand, since short-sale constraints can prevent most investors from reacting to negative information unless they already hold a stock, a negative forecast should generate trading from a narrower set of investors.[8]

An analyst can also increase trading volume by revising his earnings forecasts frequently. Analysts' forecast revisions have been shown to increase share trading volume (see, e.g., Ajinkya, Atiase, and Gift (1991)) and to significantly affect stock

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[6]Some brokerage firms acknowledge explicitly tying their analysts' compensation to the magnitude of trading commission revenues that their research generates. See, for example, the case of Soleil Research, Inc., discussed in Vickers (2003).

[7]Carleton, Chen and Steiner (1998) find that brokerage analysts appear to inflate their stock recommendations. Jackson (2005) shows theoretically that analysts' incentives for trade generation can lead to an optimistic forecast bias. Hayes (1998) develops a model to analyze how commission-based incentives and short-sale constraints can affect analysts' information gathering decisions. Ljungqvist, et al. (2007) find that analysts employed by larger brokerages issue more optimistic recommendations and more accurate earnings forecasts.

[8]Numerous regulations in the United States increase the cost of selling shares short (see Dechow, Hutton, Meulbroek and Sloan (2001)). Furthermore, traditional mutual funds that qualify as SEC-registered investment companies cannot derive more than 30% of their profits from short sales. Thus, it is not surprising that the vast majority of stock trades are regular purchases and sales rather than short sales. For example, over the 1994-2001 period, short sales comprised only about ten percent of the annual New York Stock Exchange trading volume (see NYSE (2002)).

prices apart from earnings news, dividends, or other corporate announcements (see, e.g., Stickel (1991)). From one perspective, a positive relation between trading volume and the frequency of forecast revisions can be beneficial to investors. For example, if revising forecasts is a costly, then analysts whose compensation is tied (directly or indirectly) to commission revenue may be more willing to issue timely revisions that reflect his changing earnings expectations. Indeed, previous work has established a link between analysts' forecasting frequency and their ultimate accuracy (see, e.g., Stickel (1992) and Clement and Tse (2003)).

However, the prospect of boosting commissions may lead an analyst to revise his forecasts too frequently even when there is little or no new information. This perverse 'churning' behavior, despite being anticipated by rational investors, could be profitable for an analyst if investors assign a positive probability of genuine information content to the revisions.[9] If churning incentives are important, then one would expect that, relative to independent analysts, conflicted analysts will revise their forecasts more frequently and substantially and yet will not end up being more accurate.

As in the case of IB conflicts, concerns about loss of reputation can limit abusive analyst behavior stemming from brokerage conflicts. The importance of reputational concerns may depend on market conditions, on the time period in question, and on characteristics of analysts and their employers. Hence, the net relation between the magnitude of brokerage conflicts and the quality of LTG or quarterly EPS forecasts is ultimately an empirical issue.

3. Sample and data

We obtain data on revenues of analyst employers from annual filings made with the SEC. Under Section 17 of the Securities Exchange Act of 1934, all registered broker-dealer firms in the United States, whether public or private, are required to file annual audited financial reports with the SEC. The requisite filings, referred to as x-17a-5 filings, must contain a statement of financial condition (balance sheet), a statement of

[9]Irvine (2004), using transactions data from the Toronto Stock Exchange, documents that a brokerage firm's market share of trading in a stock tends to increase when its analyst issues a forecast further away from the consensus. He also finds, however, that greater forecast bias by itself does not increase market share.

income, a statement of changes in financial condition, and a statement detailing net capital requirements.

Our sample construction begins with the set of all broker-dealer firms listed in the May 2003 version of Thomson Financial's I/B/E/S Broker Translation File, which contains 1,257 entries. Of these entries, 159 correspond to forecast-issuing firms that chose to withhold their names from the Broker Translation File. For each of the remaining 1,098 firms with names available, we conduct a manual keyword search for x-17a-5 forms using Thomson Financial's Global Access database and the public reading room of the SEC. Electronic form filing was first mandated by the SEC in 1994, so the availability of x-17a-5 filings before 1994 is extremely limited. Therefore, we restrict our sample to the 1994-2003 time period.

Out of the 1,098 firms for which we have names, 318 firms did not file an x-17a-5 form with the SEC during our sample period, either because they were based in a jurisdiction outside of the U.S. or because they were not active broker-dealers during the period. The filings for an additional 81 firms were not available electronically through Global Access. Finally, because the revenue breakdown of broker-dealers is a key data item used in this study, we exclude 454 firms for which this data is not available. These firms chose to withhold the income statement portion of their x-17a-5 filings from the public under the SEC's confidential treatment provision.[10]

Because broker-dealer firms enter our sample only when they choose to publicly disclose their income statements, we face a potential sample selection bias if firms' tendency toward disclosure is systematically related to the nature of the firms' conflicts of interest. But this bias does not appear to be serious for our purposes for two reasons. First, the average levels of forecast characteristics of interest in this study (i.e., the bias, error, and revision frequency of quarterly EPS forecasts and the level of LTG estimates) are similar between private securities firms that either report or withhold their revenue breakdown information. Second, we conduct all of our main tests separately for forecasts issued by private broker-dealers and those issued by publicly-traded broker-dealers.

[10]Under the Securities Exchange Act, broker-dealers are permitted to obtain confidential treatment of the income statement portion of an x-17a-5 filing if disclosure of the income statement to investors could harm the firm's business condition or competitive position.

There is no selection bias for the latter sub-sample because all publicly-traded firms are required to disclose their income statements in annual 10-K filings. The results for the two groups of firms are very similar.

The above selection procedure yields a sample of 245 firms. We further eliminate 20 instances in which the same firm appears in the Broker Translation File under multiple names or codes. Thus, for 225 unique firms we have data on total revenue and its key components for at least one year during the sample period.

We augment the sample by identifying all broker-dealer firms in I/B/E/S that were publicly-traded on the New York Stock Exchange (NYSE), American Stock Exchange (AMEX), or Nasdaq. Of the 44 firms identified as publicly traded, 21 firms do not disclose revenue information in their x-17a-5 filings. For these 21 firms, we use annual 10-K filings to gather financial data on revenues, revenue components, and balance-sheet items. Thus, the sample of firms for which we have revenue breakdown[11] data includes 246 broker-dealers, of which 44 are publicly traded. Of these, 163 broker-dealers (including 39 public companies) issued at least one forecast on I/B/E/S during our sample period.

Table 1 shows descriptive statistics for our sample of broker-dealers, analysts, and forecasts. Panel A describes the size and revenue breakdown for broker-dealers for the 2002 fiscal year. The first three columns are for the full sample, and the next three columns are for the sub-sample of publicly-traded firms. The median securities firm is quite small, with total revenue of only $3.25 million. The majority of firms have no IB revenue. The median revenue from brokerage commissions is $1.6 million. Not surprisingly, the publicly-traded securities firms in the sample are much larger, with median IB revenue of $31 million and median brokerage commission revenue of $50 million.

Panel B of Table 1 reports statistics, both for the full sample of firms and for the sub-sample of publicly-traded firms, on the fraction of total revenue coming from either IB or brokerage commission. For the full sample of all firm-years, about half of the typical

[11]Securities firms report revenue breakdown into revenues from investment banking, from brokerage, and from other businesses. The last category includes asset management, proprietary trading, market making, and margin lending.

firm's total revenue comes from brokerage; the revenue from IB is negligible. The fraction of IB (brokerage) revenue ranges from 0 to 1 with a median of .004 (.488) and mean of .112 (.506). For the sub-sample of publicly-traded securities firms, the corresponding range for the IB (brokerage) revenue fraction is from 0 (.005) to .913 (.999) with a median of .114 (.362) and mean of .137 (.393). Thus, compared to private securities firms, publicly-traded firms derive a substantially greater proportion of their revenue from IB.

We obtain forecasts and reported earnings per share (EPS) numbers from the I/B/E/S U.S. Detail History File for the time period from January 1, 1994 to June 30, 2003. All EPS forecast and reported EPS numbers are converted to primary EPS numbers using the dilution factors provided by I/B/E/S. Our sample includes all quarterly EPS and LTG forecasts made by individual analysts working for broker-dealer firms for which we have revenue information; it excludes forecasts made by analyst teams.

In Panel C, characteristics of EPS and LTG forecasts are reported for the entire sample period. Following much of the literature on analysts' earnings forecasts, we compute forecast bias as the difference between actual EPS and forecasted EPS, divided by the stock price twelve months before quarter-end. We define forecast inaccuracy as the absolute value of forecast bias. Bias, inaccuracy, and forecast age are all computed from an analyst's latest forecast for a company during a quarter. The median EPS forecast is slightly pessimistic, but the magnitude of the pessimism is not large—roughly 1.3 cents on a $50 stock for forecasts made over the one-month or three-month period before quarter-end. The median forecast inaccuracy is much larger, about 5.5 cents on a $50 stock for both forecast periods. For long-term earnings growth projections, the median forecast level is strikingly high, about 16% per year.[12] Over the three (six) month period preceding quarter-end, the median analyst following a company issues just one quarterly EPS forecast; the mean number of forecasts is 1.3 (1.7).

Panel D reports characteristics of individual analysts and their employers. The number of analysts employed by the analyst's firm, number of companies covered, and number of I/B/E/S industry groups covered, are all measured over the calendar year in

[12]I/B/E/S defines a long-term growth forecast as the expected annual growth in operating earnings over a company's next full business cycle, usually a period of three to five years.

which forecasts occur. We exclude analysts that are present in the EPS detail file in 1983 (the first year for which quarterly EPS forecasts are available through I/B/E/S) because we cannot fully observe the employment histories of these analysts. Overall, analysts in our sample do not appear to cover companies for long periods of time. The median company-specific forecasting experience of an analyst is about 1.1 years; her median general forecasting experience is about three years.[13] The median analyst works for a securities firm that employs 61 analysts and tracks nine companies in two different four-digit I/B/E/S S/I/G[14] industry groups.

Appendix Table A.1 lists, for fiscal year 2002, the largest analyst employers as well as the largest employers with either no IB or no brokerage business. As Panel A shows, Adams, Harkness, & Hill, Inc. is the largest employer in our sample without any IB business. The firm employs 23 analysts and has total revenue of about $62 million, all of which consists of brokerage commissions.[15]

Analyst research is typically financed via a firm's brokerage business. Consequently, almost all sell-side analysts are employed by firms with at least some commission revenue. Analyst employers with no such revenue tend to be tiny boutique firms. Panel B indicates that there were only two such firms in 2002. Both firms were start-ups. One employed eight analysts, the other employed one. Finally, Panel C lists the five largest employers of analysts. Not surprisingly, these firms are among the most prominent and well-capitalized Wall Street securities firms. Merrill Lynch is the largest employer, employing 231 forecast-issuing analysts. Of Merrill Lynch's total 2002 revenues of $18.6 billion, $2.4 billion is from IB, $4.7 billion from brokerage commissions, and the rest from other businesses such as asset management and proprietary trading.

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[13]Analyst experience appears to be short for several reasons. First, we only measure experience issuing quarterly EPS forecasts. Any additional experience issuing LTG forecasts or stock recommendations is not included in our measure. Second, securities firms hired a number of new analysts during the late 1990s stock market boom, a time period included in our sample. Third, company-specific forecasting experience is low because of large turnover in the portfolio of stocks followed by an analyst. This happens particularly after analysts change employers, which occurs quite frequently.

[14]Sector / Industry / Group code.

4. Empirical results

We present our results on forecast accuracy in section 4.1, forecast bias in section 4.2, the level of LTG forecasts in section 4.3 and revisions in quarterly forecasts in section 4.4.

4.1. Forecast accuracy

We begin with univariate comparisons of forecast accuracy. Table 2 compares quarterly EPS forecast inaccuracy for analysts employed at firms with and without significant IB (or brokerage) business. We define a broker-dealer firm to have significant (insignificant) IB business if, at the end of the preceding fiscal year, its IB revenue as a percentage of its total revenue was in the top (bottom) quartile among all broker-dealers in the sample. A similar definition applies for brokerage commission business. All of the univariate comparisons are conducted at the level of the company. In other words, for each company in each quarter, we compute the mean forecast error for each type of securities firm; we then compare the resulting sets of matched pairs. Only the latest forecast made by an analyst during a quarter is used in the computation.

Panel A shows results for forecasts issued over the period of one month prior to quarter-end. Each set of two rows in the panel shows the mean and median values of our forecast accuracy measure for firms without and with significant IB (or brokerage) business. These are followed by a row showing p-values for differences between the two rows. The rows labeled 1 and 2 are for firms without and with significant IB business. The rows labeled 3 and 4 are for firms without and with significant brokerage business. Rows 5 and 6 and rows 7 and 8 conduct comparisons between firms with and without a particular type of business, conditional on the absence of the other type of business. The basic message from Panel A is that forecasts of analysts employed by firms with significant brokerage business (row 4) are somewhat less accurate than forecasts made by the control group of analysts (row 3). This finding holds even if IB business is insignificant (row 6 versus row 5).

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[15]Commission revenue slightly exceeds total revenue, which includes a loss from the firm's proprietary trading activities.

Panel B shows corresponding results for forecasts made over the three-month period prior to quarter-end. Here, the results for firms with versus without significant brokerage operations mirror those in Panel A. In addition, analysts employed by firms with significant IB but no significant brokerage business (row 8) make forecasts that are somewhat more accurate than forecasts made by the control group of analysts (row 7).

We next conduct regression analyses linking forecast inaccuracy to our measures of conflict severity. In these regressions, we include variables that have been found in prior research (e.g., Mikhail, Walther and Willis (1997), Clement (1999), and Jacob, Lys and Neale (1999)) to affect analysts' forecast accuracy, such as forecast age, employer size, forecasting experience, and workload. Since the publicly-traded and private securities firms in our sample likely differ in ways that are not fully captured by size, we also control for public versus private status. Our basic model is the following:

(1) $NAFE_{ijt} = b_0 + b_1\, IB_{it} + b_2\, COM_{it} + b_3\, AGE_{ijt} + b_4\, SIZE_{it} + b_5\, CEXP_{ijt}$
$+ b_6\, GEXP_{it} + b_7\, NCOS_{it} + b_8\, NIND_{it} + b_9\, PUBLIC_{it} + e_{ijt}$,

where the subscripts denote analyst i following company j for year-quarter t and the variables are defined as follows:

NAFE = Normalized absolute forecast error = forecast inaccuracy, as defined in section 3,

IB (or COM) = IB (or commission) revenue as a percentage of total revenues of an analyst's employer,

AGE = Number of days between forecast date and earnings release,

SIZE = Natural log of one plus the number of analysts employed by a firm in year t,

CEXP = An analyst's company-specific forecasting experience = Number of years an analyst has been following the company,

GEXP = General experience as analyst = Number of years an analyst has been issuing forecasts to I/B/E/S,

NCOS = Number of companies followed by an analyst over the calendar year,

NIND = Number of different 4-digit I/B/E/S S/I/G industries followed by an analyst over the calendar year, PUBLIC =1, if a securities firm is publicly-traded on NYSE, AMEX or NASDAQ, 0 otherwise, and

e = the error term.

The main explanatory variables of interest in equation (1) are our measures of conflicts faced by an analyst, IB and COM. These variables are measured at the level of a securities firm. We implicitly assume that from the perspective of an individual analyst, IB and COM are given, exogenous quantities that cannot be affected directly by the choice of a forecast. We use three alternative econometric approaches to estimate equation (1). The first approach is a pooled OLS regression, where t-statistics are computed using White's (1980) correction for heteroskedasticity. The unit of observation in the regression is an analyst-company-year-quarter (e.g., the Salomon analyst following IBM for the quarter ended March 2003). Our second approach follows Fama and MacBeth (1973), where we estimate cross-sectional regressions for each year-quarter and make inferences based on the time-series of coefficient estimates.[16] In both of these approaches, we include industry dummies as well as the natural logarithm of the followed company's market capitalization one year prior to quarter end. Finally, in the third approach, we estimate panel regressions where we treat company-year-quarter effects as fixed, because we are only interested in determining whether a particular analyst characteristic (namely, independence) is related to forecast inaccuracy. By focusing on differences across analysts following a given company for a given year-quarter (e.g., the March 2003 quarter for Microsoft), this approach avoids the need to control for characteristics of the company and the time period in question.[17] The regressions exclude a small number of observations for which an employer's total revenues are zero or negative due to securities trading losses.

Table 3 shows the results of our regressions on forecast inaccuracy. For each of the three estimation approaches, the table shows two variants of model (1): one excluding the PUBLIC dummy variable and the other including it. Panel A (B) shows results for

[16]In the Fama-MacBeth regressions reported in Tables 3 and 5, we exclude three quarters that have an insufficient number of observations to perform the estimation.

[17]See Wooldridge (2002) for an exposition of the fixed effects panel regression model. This approach has been employed by several studies of analyst forecasts (see, e.g., Clement (1999) and Agrawal, Chadha and Chen (2006)).

forecasts made within one month (three months) before quarter-end. Notably, the coefficients of the IB and COM variables are statistically indistinguishable from zero in all six estimations.[18] In other words, there is no indication in either panel that an analyst's forecast accuracy is related to the proportion of his employer's revenues coming from either IB or brokerage business.[19] While conflicts with IB or brokerage may affect the accuracy of analyst forecasts in particular cases, the effect does not show up systematically in the data. As expected, the regressions show that forecast inaccuracy is greater for older forecasts and is smaller for larger companies. There is only limited evidence that forecast inaccuracy is different for analysts employed by publicly-traded versus private securities firms.

4.2. Forecast bias

Table 4 shows univariate comparisons, similar to the accuracy comparisons in Table 2, of forecast bias between different types of employers. Differences in mean bias between different employer types are mostly insignificant. Based on comparisons of median values, analysts at firms with significant IB (brokerage) business appear to be slightly more pessimistic (optimistic) in both forecast periods.

Table 5 shows estimated coefficients from regressions of forecast bias using the three econometric approaches employed in Table 3. The explanatory variables are the same as in equation (1). Here too, the unit of observation in the pooled OLS and fixed effects regressions is an analyst-company-year-quarter. In both panels, the coefficients of IB and COM variables are insignificant under each of the three estimation approaches. There is no evidence that an analyst's forecast bias is systematically related to the magnitude of potential conflicts with his employer's IB or brokerage business. Forecasts made earlier are more optimistic, consistent with the pattern found by prior studies (e.g., Brown, Foster and Noreen (1985) and Richardson, Teoh and Wysocki (2004)). An

[18]The correlation between IB and COM is -.17. Throughout the paper, results are similar when we include IB and COM variables one at a time in the regressions.

[19]These and subsequent results are generally similar when we replace the continuous IB and COM variables in each regression with binary dummy variables indicating either positive revenue or revenue over $10 million.

analyst's optimism increases with his company-specific forecasting experience and decreases with company size. All of these relations are statistically significant.

4.3. Long-term earnings growth (LTG) forecasts

The univariate comparisons in Table 6 of long-term (three to five year) earnings growth forecasts reveal some notable differences. For example, mean growth forecasts are slightly less optimistic for analysts employed by firms with significant IB business (row 2) compared to the control group of analysts (row 1). For analysts employed by firms with substantial brokerage business (rows 4 or 6), LTG forecasts are higher than forecasts of the control group. For analysts employed by firms with significant IB but insignificant brokerage business (row 8), LTG forecasts are higher than forecasts for the control group (row 7). But the sample sizes in this last comparison are quite small, so they do not warrant strong conclusions.

Table 7 shows the results of Fama-MacBeth regressions and fixed effects regressions explaining LTG levels. We do not use pooled OLS regressions here because of a natural quarter-to-quarter serial dependence in the level of growth forecasts for a company. The unit of observation in the panel regressions is an analyst-company-year-quarter. The explanatory variables are the same as in equation (1), except that the forecast AGE variable is no longer relevant and is hence excluded. In the fixed effects regressions, the level of analysts' LTG forecasts increases with the proportion of their employers' revenues from brokerage business (COM). The magnitude of this effect is non-trivial. For instance, an increase in COM from the first to the third quartile of the sample is associated with an increase in the level of LTG of about 0.82%[20]. The level of LTG forecasts decreases with the size of the analyst's employer. In the Fama-MacBeth regressions, the level of LTG forecasts decreases in an analyst's company-specific forecasting experience and the number of companies followed by the analyst; it increases in the number of industry groups the analyst follows. All these relations are statistically significant.

4.4. Frequency of forecast revision

Table 8 shows results of panel regressions explaining a fourth aspect of analysts' forecasts, namely, the frequency of quarterly EPS forecast revisions. The dependent variable in the OLS specification (column (1)) and the Poisson specification (column (3)) is the number of EPS forecasts an individual analyst issues for a given company during the three-month period preceding the end of a quarter. The dependent variable in the logistic regressions (column (2)) is an indicator variable that equals one if an analyst issues multiple forecasts during the period; it equals zero otherwise. The unit of observation in the regressions is an analyst-company-year-quarter. All three specifications include industry and year-quarter dummies.[21] The explanatory variables are the same as in equation (1), except that the IB and AGE variables are excluded because we have no *a priori* reason to expect a systematic relation between these variables and the frequency of forecast revision. T-statistics are computed using White's correction for heteroskedasticity.

Under each of the three specifications, we find that analysts employed by firms with greater proportions of revenue from brokerage business (COM) issue more frequent forecast updates over the course of the quarter. This result is highly statistically significant. Moreover, the magnitude of this effect appears to be non-trivial. For example, in the OLS specification, an increase in COM from the first to the third quartile of the sample leads to an increase of about .04 in the number of forecasts, or about 3% of the sample mean. Table 8 also reveals that an analyst is likely to revise his forecast more often when the followed company is larger, when his employer is larger, when he has more company-specific forecasting experience, when he follows more companies, when he has less general forecasting experience, or when he covers fewer industries. All of these relations are statistically significant.

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[20]While an increase in the annual earnings growth rate of 0.8% may seem inconsequential, equity values (e.g., in dividend growth models) tend to be quite sensitive to even small changes in expectations of growth rates of dividends and earnings.

5. Interpretation of results on forecast revision frequency

As discussed in section 2.2, the positive relation we find between COM and forecast revision frequency in section 4.4 above is consistent with two distinct motives. On the one hand, an analyst who is compensated for generating commission revenue should be more willing to devote time and effort to making timely forecast revisions that reflect updated expectations about earnings. We refer to this as the 'investor welfare' motive. Alternatively, the prospect of boosting commissions can lead an analyst to revise his forecasts frequently even with little or no new information. Frequent forecast revisions can be particularly effective in getting investors to churn their portfolios if the absolute magnitudes of successive changes in forecasts are large. We call this the 'churning' motive. While the investor welfare and churning motives are not mutually exclusive, the first is consistent with maximization of investors' interests, and the second is not. We attempt to distinguish between these two motives by conducting three tests, presented in sections 5.1 through 5.3.

5.1 Commission incentives, earnings uncertainty and revision frequency

As a first test of the two motives for making frequent forecast revisions, we add a measure of earnings uncertainty to the explanatory variables in the Table 8 regressions of forecast revision frequency. The more uncertain are a company's earnings for a given quarter, the greater will be investor demand for frequent forecast updates. Following Johnson (2004), we measure earnings uncertainty by the dispersion (i.e., standard deviation) of analyst forecasts at the beginning of the quarter. A positive coefficient on forecast dispersion would tend to confirm the investor welfare motive. At the same time, if the coefficient of COM is still positive after controlling for dispersion, this finding would be consistent with the churning motive.

We find that the coefficients of both forecast dispersion and COM are positive and statistically significant at the .001 level or better in the extended versions of all six models in Table 8. Our evidence thus suggests that the frequency of forecast updates is partly driven by investor demand for updated information. But, after controlling for this

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[21]We do not treat company-year-quarter effects as fixed here because doing so results in the loss of a large number of groups with no variation in the dependent variable.

effect, commission incentives still play an important role in an analyst's decision on how frequently to revise his forecast. To save space, we do not report these results in a table.

5.2 Commission incentives and churning

For our second test of the motives underlying frequent forecast revisions, we devise two simple measures of churning,[22] denoted $CHURN_1$ and $CHURN_2$, and estimate the following regression:

$$\text{(2)} \qquad CHURN_{ijt} = bo + b_1\, COM_{it} + b_2\, SIZE_{it} + e_{ijt},$$

where the subscripts denote Analyst i following Company j for Year-quarter t, COM and SIZE are as defined as in section 4.1 above, and the churning measure is defined as follows:

CHURN = $CHURN_1$ or $CHURN_2$,

$CHURN_1$ = Mean absolute forecast revision = $\sum_{k=2}^{n} |d_k - d_{k-1}| / (n-1)$,

$CHURN_2$ = Mean squared forecast revision = $\sum_{k=2}^{n} (d_k - d_{k-1})^2 / (n-1)$,

$d_k = F_k / S$,

F_k = kth forecast of EPS made by an analyst for a given company-year-quarter,

S = Stock price 12 months before quarter-end,

n = Number of forecasts made by an analyst for a given company-year-quarter over the 6-month period prior to quarter-end, and

e = the error term.

The churning story suggests that the stronger is the commission incentive, the larger should be the absolute magnitude of successive changes in forecasts. This implies that the coefficient b_1 in equation (2) should be positive. On the other hand, the investor welfare story, under which forecast revisions are aimed purely at providing updated information to investors in a timely fashion, implies no particular relation between the strength of commission incentives and the magnitude of successive changes in an analyst's forecasts.

[22]Both measures capture a salient aspect of churning, namely the average distance between successive changes in an analyst's forecast, without regard to gains in forecast accuracy.

We estimate equation (2) in a pooled OLS regression with robust standard errors. The estimate of the coefficient b_1 is significantly positive using either $CHURN_1$ or $CHURN_2$ as the dependent variable, with t-values of 2.68 and 2.81, respectively. In other words, the absolute magnitude of successive changes in an analyst's forecasts appears to be positively related to the strength of brokerage conflicts.

These churning variables measure the magnitude, rather than the frequency, of successive forecast revisions by an analyst. We next examine churning measures that take into account both, by multiplying each measure by (n-1). We then re-estimate equation (2) as earlier. Once again, the estimate of the coefficient b_1 is significantly positive, with t-values of 4.62 and 3.08, respectively, for the two churning measures. Overall, this evidence is consistent with the idea that analysts employed by firms where brokerage business is more important issue forecast updates that are more frequent and larger in magnitude in an attempt to generate trades. These results are not shown in a table to save space.

5.3. Boldness, trade generation and forecast accuracy

One characteristic of a forecast revision that is generally related to both accuracy and trade generation is boldness, i.e., how much the new forecast departs from the consensus. Compared to forecasts that herd with the consensus, bold forecasts tend to be more accurate (see, e.g., Clement and Tse (2005)), and they generate more trades for the analyst's firm (Irvine (2004)). In addition, Clement and Tse find that a bold revision tends to be more accurate than the original forecast. Motivated by these prior findings, we conduct tests examining the link between the boldness of a revised forecast and the incremental change in forecast accuracy for analysts facing different degrees of brokerage conflicts. Specifically, we estimate the following pooled regression by OLS:

$$(3) \qquad \Delta NAFE_{ijt} = b_0 + b_1\, BOLDNESS_{ijt} * HCOM_{it} + b_2\, BOLDNESS_{ijt} * LCOM_{it} + b_3\, NDAYS_{ijt} + e_{ijt},$$

where the subscripts denote analyst i following company j for year-quarter t, NAFE is forecast inaccuracy as defined in section 4.1 above, and the other variables are defined as follows:

$\Delta NAFE_{ijt} = NAFE_{ijt} - NAFE_{ij,t-1}$,

$BOLDNESS_i = |F_i - F| / S$,

F_i = Forecast of analyst i for a given company-year-quarter,

F = Consensus forecast for the company-year-quarter,

S= Stock price twelve months before quarter-end,

$HCOM_i$ = 1, if analyst i works for an employer with high (above-median) COM,

= 0 otherwise,

$LCOM_i = 1 - HCOM_i$,

NDAYS = Number of days between the current forecast and prior forecast of an analyst about a company-year-quarter, and

e = the error term.

The investor welfare story predicts that $b_1 = b_2 < 0$, while the churning story predicts that $b_1 > b_2$. In other words, if forecast revisions are aimed purely at providing timely and accurate information to investors, then the relation between forecast inaccuracy and boldness should be negative and of the same magnitude for analysts facing high or low degrees of brokerage conflicts. But if frequent revisions are at least partly aimed at inducing investors to churn their portfolios, then the relation between forecast inaccuracy and boldness should be less (more) negative for analysts who face higher (lower) degrees of brokerage conflict.

Our estimation of equation (3) indicates that $\hat{b}_1$ = -.13 and $\hat{b}_2$ = -.31; both coefficients are significantly different from zero. The test of the null hypothesis that $b_1 = b_2$ has an associated p-value of less than .0001. In other words, bold forecast revisions do tend to increase forecast accuracy, but this gain in accuracy is significantly greater for analysts with lower brokerage conflicts. These results suggest that, although the investor welfare story holds, churning is also an important motive for forecast revisions. We obtain qualitatively similar results if we replace the boldness variable by the change in boldness or if we replace the continuous measure of boldness in equation (3) with a binary measure used in Clement and Tse (2005). Once again, we do not show these results in a table to save space.

6. Sub-sample results

We next examine two interesting partitions of our sample. We present the results for technology versus other sectors in section 6.1 and the results for the late 1990s versus other time periods in section 6.2.

6.1 Technology versus other industry sectors

Numerous stories in the media suggest that conflicts of interest may have been more pronounced in the technology sector than in other industry sectors during our sample period. We examine this idea by replacing the IB variable in model (1) of Tables 3, 5 and 7 by two variables, IB*TECH and IB*NTECH, and replacing the COM variable in Tables 3, 5, 7 and 8 by COM*TECH and COM*NTECH. The binary variable TECH equals 1 if the first two digits of the I/B/E/S S/I/G code of a followed company are '08' (i.e., the company belongs to the technology sector); otherwise, TECH equals zero. NTECH is defined as 1 - TECH.

We find no significant relation between the accuracy or bias in an analyst's quarterly earnings forecasts and the importance to her employer of IB or brokerage business either in the technology sector or in other industry sectors. The frequency of an analyst's forecast updates is positively related to the importance of brokerage business to her employer in each sector, with no significant difference in the coefficient estimates. But the level of analysts' long-term growth (LTG) forecasts is positively related to the importance of IB and brokerage business only for the technology sector; it is insignificant for the remaining sectors as a group. This difference is statistically significant. To save space, we do not tabulate these results.

6.2 Late 1990s versus other time periods

The late 1990s was a period of booming stock prices. Media accounts and the timing of regulatory actions suggest that conflicts of interest were particularly severe during this period. To examine this idea, we replace the IB variable in model (1) of Tables 3, 5 and 7 by two variables: IB*LATE90S and IB*NLATE90S. Similarly, we replace the COM variable in Tables 3, 5, 7 and 8 by COM*LATE90S and

COM*NLATE90S. The variable LATE90S equals 1 for forecasts made for time periods ending during 1995-99; it equals zero otherwise. NLATE90S equals 1 - LATE90S.

There is no significant relation between the accuracy or bias in an analyst's quarterly earnings forecasts and the importance to his employer of IB or brokerage business for either the late 1990s or other time periods in our sample. The level of LTG forecasts is unrelated to IB during both time periods. LTG is positively related to COM during the late 1990s and is unrelated to it during other time periods, but the difference is statistically insignificant. The probability of forecast revision is positively related to COM during both time periods, but the coefficient of COM is significantly lower during the late 1990s than during other periods. Once again, we do not show these results in a table to save space.

7. Summary and conclusions

The landmark settlement that prominent Wall Street firms reached with regulators in April 2003 mandated sweeping changes in the production and dissemination of sell-side analyst research. Among its key provisions, the settlement required securities firms to create and maintain greater separation between equity research and IB activities, and to provide brokerage customers with research reports produced by independent research firms. The basic premise underlying such requirements is that independent analysts do in fact produce research that is superior to that of analysts who face potential conflicts of interest from their employers' other businesses.

In this paper, we empirically examine whether the quality of analysts' forecasts of earnings or earnings growth is related to the magnitude of potential conflicts of interest arising from their employers' IB and brokerage businesses. Using a unique dataset containing the breakdown of securities firms' revenues from IB, brokerage, and other businesses, we investigate the effects of analyst conflicts on four aspects of their forecasts: accuracy and bias in quarterly earnings forecasts, optimism in LTG forecasts, and the frequency of quarterly forecast revisions.

Our investigation reveals that quarterly EPS forecast bias and accuracy do not appear to be systematically related to the importance of IB or brokerage business to analysts' employers. This result also holds for forecasts made for companies within the technology sector as well as forecasts made during the late-1990s stock market boom, contexts in which conflicts of interest may have been particularly severe. In addition, the absence of a link between analyst conflicts and quarterly forecast bias or accuracy holds for publicly-traded as well as private analyst employers, and it is robust to several alternative measures of conflict severity.

We find, however, that the degree of relative optimism in analysts' LTG forecasts tends to increase with the share of their employers' revenues derived from brokerage commissions. We also find that the frequency of forecast revisions bears a significant positive relationship with the share of revenues from brokerage business. We conduct several tests to distinguish between alternative explanations of this finding on forecast revision frequency. The results of these tests suggest that analysts' trade generation incentives can indeed impair the quality of stock research. Our findings imply that distortions in analyst research are unlikely to be completely eliminated by regulations that focus solely on IB conflicts. The precise nature of trade generation incentives, how they impact analyst behavior, and how they might be mitigated all appear to be fruitful avenues for future research.

Our findings also highlight a key difference in analysts' short-term (quarterly EPS) versus long-term (EPS growth) forecasting behavior. While analysts do not appear to systematically respond to conflicts by biasing short-term forecasts, they do appear to succumb to conflicts when making long-term growth projections. What accounts for this difference? One possibility is that short-term forecasts allow the labor market to assess an analyst's performance against an objective, well-defined benchmark. If an analyst allows his short-term forecasts to be affected by the conflicts he faces, his deception can be revealed with the very next earnings release, damaging his reputation and livelihood. But with long-term forecasts, analysts may not face the same degree of market scrutiny. Investors' memories may be short, and analysts may be able to get away with revising their initial flawed projections. A second possible explanation, suggested by dividend growth models, is that equity valuations depend more on long-term growth rates than on the next quarter's earnings, and analysts use the most effective means available to prop up a stock. We leave a complete resolution of this issue to future research.

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Table 1
Sample Characteristics

This table provides descriptive statistics on broker-dealers, analysts, and forecasts. The sample includes I/B/E/S quarterly earnings and long-term earnings growth (LTG) forecasts made between January 1994 and June 2003 and corresponding annual financial information for broker-dealer firms. Panel A contains statistics on revenue components for broker-dealer firms for fiscal years ending in 2002. A broker-dealer is public if it is traded on the NYSE, Nasdaq, or AMEX. Panel B shows, over the sample period 1994-2003, the distribution of the fraction of total revenues generated from investment banking (IB) or brokerage businesses. N is the number of firm-years. Panel C reports characteristics of long-term growth forecasts and quarterly EPS forecasts over the entire sample period. Bias is computed as (actual EPS-forecast EPS) divided by the stock price twelve months before quarter-end. Forecast error is measured as the absolute value of forecast bias. Statistics for bias, accuracy and forecast age are based on the latest forecast made by each analyst over the relevant period. Forecast age is the number of days between the forecast date and the earnings release. In Panels B and C, forecasts and broker-years are excluded when total revenues are negative or when fractions of revenue exceed one. In Panels B, C, and D, analyst teams and analysts for which forecasting experience could not be determined are excluded. In Panel C, the periods of one, three and six months refer to periods before quarter-end. Panel D reports analysts' experience and workload characteristics measured on an annual basis over the entire sample period.

Panel A: Broker-Dealer Firm Characteristics, 2002

	All Broker-Dealers			Public Broker-Dealers		
	Mean	**Median**	**# of Firms**	**Mean**	**Median**	**# of Firms**
Revenue ($ millions)	848.35	3.25	151	4953.32	176.15	25
Investment Banking Revenue ($ millions)	97.28	0	151	572.17	30.73	25
Brokerage Commission Revenue ($ millions)	154.16	1.60	151	847.06	49.80	25
Other Revenue ($ millions)	596.90	0.43	151	3534.09	76.68	25

Panel B: IB and Commission Revenues Divided by Total Revenue, 1994-2003

	Distribution of the Fraction of Total Revenue							
Source of Revenue	***N***	**Min**	**1st Quart.**	**Median**	**3rd Quart.**	**Max**	**Mean**	**Std. Dev.**
All broker-dealers								
IB fraction	972	0	0	0.004	0.136	1	0.112	0.194
Brokerage commission	972	0	0.207	0.488	0.853	1	0.506	0.341
Public broker-dealers								
IB fraction	227	0	0.069	0.114	0.154	0.913	0.137	0.137
Brokerage commission	227	0.005	0.160	0.362	0.494	0.999	0.393	0.276

Table 1 (cont.)

Panel C: Forecast Characteristics, 1994-2003				
	Mean	**Median**	**Sample Size**	**Unit of Observation**
Bias in Quarterly EPS Forecasts				
One-Month Period	-0.00017	0.00026	54,369	Forecast
Three-Month Period	-0.00039	0.00027	171,915	Forecast
Inaccuracy in Quarterly EPS Forecasts				
One-Month Period	0.0037	0.0011	54,369	Forecast
Three-Month Period	0.0039	0.0011	171,915	Forecast
LTG Forecasts (%)	19.61	16	38,209	Forecast
Number of Quarterly Earnings Forecasts				
Over Prior three months	1.325	1	188,658	Analyst-company-qtr.
Over Prior six months	1.740	1	239,102	Analyst-company-qtr.
Forecast Age (# of days)				
One-Month Period	14.001	14	59,699	Forecast
Three-Month Period	45.89	52	188,664	Forecast

Panel D: Analyst Characteristics, 1994-2003				
	Mean	**Median**	**Sample Size**	**Unit of Observation**
Company-specific forecasting experience (years)	2.25	1.11	87,244	Analyst-company-year
General forecasting experience (years)	4.32	2.97	9,387	Analyst-year
Number of analysts employed by firm	76.55	61	9,387	Analyst-year
Number of companies covered	10.19	9	9,387	Analyst-year
Number of 4-digit I/B/E/S SIG industry groups covered	2.39	2	9,378	Analyst-year

Table 2
Forecast Accuracy of Analysts Employed by Firms with Versus without Significant Investment Banking or Brokerage Business

This table presents univariate comparisons of quarterly EPS forecast inaccuracy between different groups of analysts classified according to whether their employer has significant investment banking (IB) or brokerage business. Panel A (B) presents results for forecasts made within one (three) month(s) of quarter-end. Forecast inaccuracy is computed as the absolute value of (actual EPS – forecast EPS) divided by the stock price measured 12 months before quarter end. Forecasts are drawn from the January 1994-June 2003 period. A broker-dealer is defined to have significant (insignificant) IB business in a given calendar year if its IB revenue as a percentage of its total revenue is in the top (bottom) quartile among all broker-dealers in the sample. Significant or insignificant brokerage business is defined similarly based on commission revenue as a percentage of total revenue. Comparisons are conducted at the level of the company-year-quarter unit. For each publicly-traded company in the I/B/E/S U.S. detail history file for which adequate data are available, forecast errors are averaged for each different type of broker-dealer firm; these averages are then compared using matched-pair t-tests for differences in means and Wilcoxon signed-rank tests for differences in distributions. *N* corresponds to the number of matched pairs. Only the latest forecasts made by individual analysts over the relevant forecast period are used. Revenue data are obtained from x-17a-5 or 10-k filings with the U.S. Securities and Exchange Commission. Forecasts are matched with annual broker-dealer financial data corresponding to the latest fiscal year preceding the date of the forecast.

Type of Firm	**A. One-month Forecast Period**			**B. Three-month Forecast Period**		
	N	**Mean**	**Median**	***N***	**Mean**	**Median**
1. Firms with no significant IB business	3683	0.0029	0.0010	16789	0.0032	0.0010
2. Firms with significant IB business	3683	0.0028	0.0010	16789	0.0031	0.0010
p-value of t-test/signed-rank test (1 vs. 2)		0.433	0.059		0.132	0.160
3. Firms with no significant brokerage business	3370	0.0026	0.0009	13982	0.0029	0.0009
4. Firms with significant brokerage business	3370	0.0029	0.0010	13982	0.0031	0.0010
p-value of t-test/signed-rank test (3 vs. 4)		0.006	0.000		0.000	0.000
5. Firms with no significant IB and no significant brokerage business	998	0.0025	0.00078	4161	0.0024	0.0008
6. Firms with significant brokerage but with no significant IB business	998	0.0029	0.00082	4161	0.0028	0.0008
p-value of t-test/signed-rank test (5 vs. 6)		0.056	0.025		0.002	0.000
7. Firms with no significant IB and no significant brokerage business	549	0.0026	0.00073	2837	0.0025	0.00082
8. Firms with significant IB but no significant brokerage business	549	0.0027	0.00073	2837	0.0023	0.00076
p-value of t-test/signed-rank test (7 vs. 8)		0.818	0.581		0.024	0.084

Table 3
Panel Regression Analysis of Quarterly Earnings Forecast Accuracy

This table reports coefficient estimates from regressions explaining errors in individual analysts' quarterly EPS forecasts made over the January 1994-June 2003 period. Panel A (B) presents results for forecasts made within one (three) month(s) of quarter-end. Only company quarters ending in March, June, September, or December are included. Forecast and reported numbers are based on primary EPS. Forecast error is computed as |reported EPS – forecast EPS| divided by the stock price twelve months before quarter-end. For each forecast period, only the latest forecast made by an analyst is included. The regressions in (1) are pooled OLS regression estimates using White's correction for heteroskedasticity. The pooled OLS regressions include industry and calendar-quarter dummies (not reported). (2) reports average coefficients obtained from Fama-MacBeth (1973) regressions performed on individual calendar quarters over the sample period. Each regression includes unreported industry dummies. In the fixed-effects regressions in (3), company-year-quarter effects are treated as fixed. Revenue data are obtained from x-17a-5 or 10-K filings with the U.S. Securities and Exchange Commission. Each forecast issued by an analyst is matched with broker-dealer revenue data corresponding to the latest fiscal year preceding the date of the forecast. Forecast age is measured as the number of days between the report date and the forecast date. Company-specific and general forecasting experience are measured as the number of years since an analyst first began issuing I/B/E/S EPS forecasts on a particular company or in general. The number of analysts employed by a firm, the number of companies covered by an analyst, and the number of industry groups covered by an analyst are measured over the calendar year of the earnings forecast. Industry groupings are based on I/B/E/S 4-digit S/I/G codes. Company market capitalization is measured in millions of dollars one year prior to quarter-end. The public brokerage dummy equals unity if a broker-dealer is traded on NYSE, AMEX, or Nasdaq and equals zero otherwise. T-statistics for coefficient estimates are in parentheses.

	Pooled OLS (1)		**Fama-MacBeth (2)**		**Company-Quarter Fixed Effects (3)**	
Panel A: One-Month Forecast Period						
Constant	-0.0083 (-6.99)[a]	-0.0083 (-6.99)[a]	-0.0040 (-2.25)[b]	-0.0049 (-2.44)[b]	0.0030 (8.82)[a]	0.0030 (8.82)[a]
IB revenue as fraction of total revenue	-0.0009 (-0.67)	-0.00089 (-0.66)	-0.0015 (-1.10)	0.0012 (0.52)	-0.00020 (-0.52)	-0.00020 (-0.52)
Commission revenue as fraction of total revenue	0.00036 (0.76)	0.00036 (0.75)	0.00076 (1.82)	-0.00018 (-0.33)	0.00014 (0.69)	0.00014 (0.70)
Forecast age	0.00009 (9.15)[a]	0.00009 (9.16)[a]	0.00009 (8.07)[a]	0.0001 (8.02)[a]	0.00003 (7.18)[a]	0.00003 (7.18)[a]
Ln (1+Number of analysts employed by brokerage)	0.00015 (1.51)	0.00011 (0.89)	0.0002 (2.00)[b]	0.00015 (1.19)	-0.00012 (-2.41)[b]	-0.00013 (-2.19)[b]
Company-specific forecasting experience * 10^{-3}	0.1799 (6.31)[a]	0.1804 (6.31)[a]	0.1750 (5.14)[a]	0.1750 (5.23)[a]	-0.0250 (-1.81)	-0.0248 (-1.81)
General forecasting experience * 10^{-3}	-0.0552 (-2.27)[b]	-0.0558 (-2.28)[b]	-0.0276 (-1.36)	-0.02667 (-1.34)	0.034 (3.27)[a]	0.0341 (3.27)[a]
Number of companies followed * 10^{-3}	0.00075 (-0.07)	0.00067 (-0.06)	0.0075 (0.51)	0.0086 (0.58)	-0.0041 (-0.82)	-0.0041 (-0.83)
Number of industry groups followed * 10^{-3}	0.0526 (0.81)	0.0538 (0.83)	-0.0222 (-0.29)	-0.0272 (-0.36)	-0.0421 (-1.47)	-0.0416 (-1.46)
Ln (Market capitalization of company)	-0.00127 (-18.71)[a]	-0.00127 (-18.63)[a]	-0.0013 (-14.54)[a]	-0.0013 (-14.57)[a]		
Public broker-dealer dummy		0.00018 (0.59)		0.0016 (2.25)[b]		0.00003 (0.25)
Number of Observations	45374	45374	45267	45267	45374	45374
Number of Groups					27704	27704
Model P-value	0.0000	0.0000			0.0000	0.0000
R^2	0.036	0.035	0.002	0.002	0.0043	0.0043

Table 3 (cont.)

Panel B: Three-Month Forecast Period

Constant	-0.0039 (-6.38)[a]	-0.0038 (-6.38)[a]	-0.0018 (-1.78)	-0.0029 (-2.64)[a]	0.0031 (20.21)[a]	0.0031 (20.19)[a]
IB revenue as fraction of total revenue	-0.00015 (-0.27)	-0.00015 (-0.28)	-0.0013 (-1.28)	0.0004 (0.26)	-0.00009 (-0.53)	-0.0001 (-0.53)
Commission revenue as fraction of total revenue	0.00019 (0.73)	0.00019 (0.74)	0.0005 (0.90)	0.00017 (0.66)	0.00004 (0.37)	0.00004 (0.38)
Forecast age	0.00003 (11.61)[a]	0.00003 (11.61)[a]	0.00003 (7.73)[a]	0.00003 (7.64)[a]	0.00002 (25.87)[a]	0.00002 (25.87)[a]
Ln (1+Number of analysts employed by brokerage)	0.00017 (2.93)[a]	0.00013 (1.98)[b]	0.00015 (2.30)[b]	0.00006 (0.79)	-0.00011 (-4.41)[a]	-0.00011 (-3.91)[a]
Company-specific forecasting experience * 10^{-3}	0.1392 (5.86)[a]	0.1397 (5.85)[a]	0.1551 (6.06)[a]	0.00015 (6.04)[a]	-0.0153 (-2.13)[b]	-0.0155 (-2.12)[b]
General forecasting experience * 10^{-3}	-0.0021 (-0.12)	-0.0026 (-0.15)	0.00053 (0.04)	0.00039 (0.03)	0.0109 (2.08)[b]	0.0109 (2.07)[b]
Number of companies followed * 10^{-3}	-0.0315 (-5.40)[a]	-0.0315 (-5.40)[a]	-0.0203 (-2.06)[b]	-0.0194 (-1.97)[b]	-0.00146 (-0.59)	-0.00147 (-0.59)
Number of industry groups followed * 10^{-3}	0.0607 (1.67)	0.0617 (1.71)	0.0228 (0.46)	0.0198 (0.39)	-0.0193 (-1.33)	-0.0191 (-1.32)
Ln (Market capitalization of company)	-0.0015 (-32.69)[a]	-0.0015 (-32.67)[a]	-0.0014 (-20.39)[a]	-0.0014 (-20.44)[a]		
Public broker-dealer dummy		0.00014 (0.80)		0.0014 (3.02)[a]		0.00002 (0.30)
Number of Observations	143477	143477	143318	143318	143477	143477
Number of Groups					61996	61996
Model P-value	0.0000	0.0000			0.0000	0.0000
R^2	0.026	0.026	0.001	0.001	0.009	0.009

[a,b] denote statistical significance in two-tailed tests at the 1% and 5% levels, respectively.

Table 4
Forecast Bias of Analysts Employed by Firms with Versus without Significant Investment Banking or Brokerage Business

This table presents univariate comparisons of quarterly EPS forecast bias between different groups of analysts classified according to whether their employer has significant investment banking (IB) or brokerage business. Panel A (B) presents results for forecasts made within one (three) month(s) of quarter-end. Forecast bias is measured as (reported EPS – forecast EPS) divided by the stock price measured twelve months before quarter end. Forecasts are drawn from the January 1994-June 2003 period. A broker-dealer is defined to have significant (insignificant) IB business in a given calendar year if its IB revenue as a percentage of its total revenue is in the top (bottom) quartile among all broker-dealers in the sample. Significant or insignificant brokerage business is defined similarly based on commission revenue as a percentage of total revenue. Comparisons are conducted at the level of the company-year-quarter unit. For each publicly-traded company in the I/B/E/S U.S. detail history file for which adequate data are available, forecast bias is averaged for each different type of broker-dealer firm; these averages are then compared using matched-pair t-tests for differences in means and Wilcoxon signed-rank tests for differences in distributions. *N* corresponds to the number of matched pairs. Only the latest forecasts made by individual analysts over the relevant forecast period are used. Revenue data are obtained from x-17a-5 or 10-k filings with the U.S. Securities and Exchange Commission. Forecasts are matched with annual broker-dealer financial data corresponding to the latest fiscal year preceding the date of the forecast.

Type of Firm	**A. One-month Forecast Period**			**B. Three-month Forecast Period**		
	N	**Mean**	**Median**	***N***	**Mean**	**Median**
1. Firms with no significant IB business	3683	0.00007	0.0002	16789	$-5.6*10^{-6}$	0.00026
2. Firms with significant IB business	3683	0.00011	0.0003	16789	0.00003	0.00029
p-value of t-test/signed-rank test (1 vs. 2)		0.747	0.028		0.493	0.0001
3. Firms with no significant brokerage business	3370	0.00003	0.00025	13982	0.00008	0.00027
4. Firms with significant brokerage business	3370	-0.00013	0.00020	13982	-0.00006	0.00025
p-value of t-test/signed-rank test (3 vs. 4)		0.138	0.0005		0.017	0.000
5. Firms with no significant IB and no significant brokerage business	998	-0.0002	0.00022	4161	0.00026	0.00026
6. Firms with significant brokerage but with no significant IB business	998	-0.0002	0.00017	4161	0.00035	0.00029
p-value of t-test/signed-rank test (5 vs. 6)		0.709	0.074		0.395	0.470
7. Firms with no significant IB and no significant brokerage business	549	-0.00037	0.0000	2837	0.00002	0.00022
8. Firms with significant IB but no significant brokerage business	549	-0.00044	0.0000	2837	0.00009	0.00025
p-value of t-test/signed-rank test (7 vs. 8)		0.620	0.934		0.447	0.008

Table 5
Panel Regression Analysis of Quarterly Earnings Forecast Bias

This table shows coefficient estimates from regressions explaining the degree of bias in individual analysts' quarterly EPS forecasts made over the January 1994-June 2003 period. Panel A (B) presents results for forecasts made within one (three) month(s) of quarter-end. Only company quarters ending in March, June, September, or December are included. Forecast and reported numbers are based on primary EPS. Forecast bias is computed as (reported EPS – forecast EPS) divided by the stock price twelve months before quarter-end. The sample includes only the latest forecast made by an analyst for a company during a given forecast period. Columns (1) show results of pooled OLS regressions that include industry and calendar-quarter dummies (not reported) and t-statistics using White's correction for heteroskedasticity. Columns (2) report average coefficient estimates from Fama-MacBeth (1973) regressions that include unreported industry dummies, performed on individual calendar quarters over the sample period. In the fixed-effects regressions in (3), company-year-quarter effects are treated as fixed. Revenue data are obtained from x-17a-5 or 10-K filings with the SEC. Each forecast issued by an analyst is matched with broker-dealer revenue data corresponding to the latest fiscal year preceding the date of the forecast. Forecast age is measured as the number of days between the report date and the forecast date. Company-specific and general forecasting experience are (continuous) measures of the number of years since an analyst first began issuing I/B/E/S EPS forecasts on a particular company or in general. The number of analysts employed by a firm, the number of companies covered by an analyst, and the number of industry groups covered by an analyst are measured over the calendar year of the earnings forecast. Industry groupings are based on I/B/E/S 4-digit S/I/G codes. Company market capitalization is measured in millions of dollars one year prior to quarter-end. The public brokerage dummy equals one if a broker-dealer firm is publicly-traded on NYSE, AMEX, or Nasdaq and equals zero otherwise. T-statistics for coefficient estimates are shown in parentheses.

	Pooled OLS (1)		**Fama-MacBeth (2)**		**Company-Quarter Fixed Effects (3)**	
Panel A: One-Month Forecast Period						
Constant	0.0045 (3.55)[a]	0.0045 (3.54)[a]	0.0050 (2.79)[a]	0.0048 (2.59)[a]	0.00086 (2.29)[b]	0.00085 (2.27)[b]
IB revenue as fraction of total revenue	0.00088 (0.64)	0.00087 (0.63)	-0.00027 (-0.16)	0.00026 (0.14)	0.00019 (0.47))	0.00019 (0.47)
Commission revenue as fraction of total revenue	-0.00017 (-0.34)	-0.00016 (-0.32)	-0.00097 (-1.71)	-0.0006 (-1.09)	-0.00019 (-0.88)	-0.0002 (-0.92)
Forecast age	-0.00006 (-5.67)[a]	-0.00006 (-5.68)[a]	-0.00006 (-4.52)[a]	-0.00006 (-4.51)[a]	-0.00003 (-5.76)[a]	-0.00003 (-5.78)[a]
Ln (1 + Number of analysts employed by brokerage)	0.00015 (1.49)	0.00023 (1.93)	0.00009 (0.65)	0.00025 (1.52)	0.00006 (1.16)	0.00009 (1.48)
Company-specific forecasting experience * 10^{-3}	-0.1149 (-3.86)[a]	-0.1158 (-3.89)[a]	-0.1193 (-3.18)[a]	-0.1187 (-3.18)[a]	-0.0073 (-0.49)	-0.0075 (-0.49)
General forecasting experience * 10^{-3}	0.0448 (1.76)	0.0458 (1.80)	0.0391 (1.49)	0.0381 (1.48)	0.026 (2.27)[b]	0.0262 (2.28)[b]
Number of companies followed * 10^{-3}	-0.0125 (-1.10)	-0.0126 (-1.11)	-0.0211 (-1.37)	-0.0219 (-1.46)	-0.0038 (-0.70)	-0.0037 (-0.68)
Number of industry groups followed * 10^{-3}	-0.060 (-0.90)	-0.0621 (-0.93)	-0.0492 (-0.67)	-0.0474 (-0.65)	-0.0737 (-2.34)[b]	-0.0754 (-2.39)[b]
Ln (Market capitalization of company)	0.00024 (3.48)[a]	0.00024 (3.48)[a]	0.00028 (3.72)[a]	0.00028 (3.71)[a]		
Public broker-dealer dummy		-0.0003 (-0.97)		-0.00026 (-0.79)		-0.00013 (-0.95)
Number of Observations	45374	45374	45267	45267	45374	45374
Number of Groups					27704	27704
Model P-value	0.0000	0.0000			0.0000	0.0000
R^2	0.008	0.008	0.001	0.001	0.003	0.003

Table 5 (cont.)

Panel B: Three-Month Forecast Period						
Constant	0.0025 (3.87)[a]	0.0025 (3.86)[a]	0.0021 (2.63)[a]	0.0030 (3.28)[a]	0.0002 (1.19)	0.0002 (1.22)
IB revenue as fraction of total revenue	-0.00066 (-1.18)	-0.00065 (-1.17)	-0.0050 (-1.08)	-0.0065 (-1.48)	0.00016 (0.78)	0.00016 (0.78)
Commission revenue as fraction of total revenue	-0.00012 (-0.43)	-0.00012 (-0.44)	-0.00054 (-1.13)	-0.00024 (-0.75)	0.00002 (0.21)	0.00003 (0.24)
Forecast age	-0.00003 (-9.39)[a]	-0.00003 (-9.39)[a]	-0.00003 (-6.04)[a]	-0.00003 (-6.01)[a]	-0.00001 (-14.88)[a]	-0.00001 (-14.89)[a]
Ln (1+Number of analysts employed by brokerage)	0.00014 (2.33)[b]	0.00017 (2.39)[b]	0.00036 (2.31)[b]	0.00042 (2.26)[b]	0.00009 (3.36)[a]	0.00008 (2.55)[b]
Company-specific forecasting experience * 10^{-3}	-0.0606 (-2.50)[b]	-0.0610 (-2.50)[b]	-0.0778 (-3.47)[a]	-0.0769 (-3.42)[a]	0.012 (1.47)	0.0121 (1.49)
General forecasting experience * 10^{-3}	-0.0126 (-0.73)	-0.0122 (-0.70)	-0.0100 (-0.70)	-0.0097 (-0.67)	0.00343 (0.59)	0.0034 (0.58)
Number of companies followed * 10^{-3}	0.0245 (4.07)[a]	0.0245 (4.08)[a]	0.0129 (1.36)	0.0121 (1.27)	-0.0019 (-0.69)	-0.0195 (-0.70)
Number of industry groups followed * 10^{-3}	-0.0920 (-2.46)[b]	-0.0928 (-2.49)[b]	-0.0808 (-1.62)	-0.0779 (-1.56)	-0.0414 (-2.55)[b]	-0.041 (-2.53)[b]
Ln (Market capitalization of company)	0.00035 (7.68)[a]	0.00035 (7.68)[a]	0.00043 (5.99)[a]	0.00043 (6.01)[a]		
Public broker-dealer dummy		-0.00011 (-0.61)		-0.0011 (-2.72)[a]		-0.00004 (0.58)
Number of Observations	143477	143477	143318	143318	143477	143477
Model P-value	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
R^2	0.005	0.005	0.001	0.001	0.003	0.003

[a,b] denote statistical significance in two-tailed tests at the 1% and 5% levels, respectively.

Table 6
Long-term Earnings Growth Forecasts of Analysts Employed by Firms with Versus Without Significant Investment Banking or Brokerage Business

Univariate comparisons of long-term (3 to 5 years) growth forecasts between different groups of analysts classified according to whether their employer has significant investment banking (IB) or brokerage business. The sample period is from January 1994 through June 2003. A broker-dealer is defined to have significant (insignificant) IB business in a given calendar year if its IB revenue as a percentage of its total revenue is in the top (bottom) quartile among all broker-dealers in the sample. Significant or insignificant brokerage business is defined similarly based on commission revenue as a percentage of total revenue. Comparisons are conducted at the level of the company-year-quarter unit. For each publicly-traded company in the I/B/E/S U.S. detail history file for which adequate data are available, LTG forecast levels are averaged for each different type of broker-dealer firm; these averages are then compared using matched-pairs t-tests for differences in means and Wilcoxon signed-rank tests for differences in distributions. *N* corresponds to the number of matched pairs. Only the latest company forecast made by an individual analyst over the appropriate quarter (March, June, September, or December) is used. Revenue data are obtained from x-17a-5 or 10-k filings with the U.S. Securities and Exchange Commission. Forecasts are matched with annual broker-dealer financial data corresponding to the latest fiscal year preceding the date of the forecast.

Type of Firm	***N***	**Mean**	**Median**
1. Firms with no significant IB business	1508	20.74	17.88
2. Firms with significant IB business	1508	19.83	17.5
p-value of t-test/signed-rank test (1 vs. 2)		0.002	0.112
3. Firms with no significant brokerage business	1578	18.58	15.9
4. Firms with significant brokerage business	1578	19.73	17
p-value of t-test/signed-rank test (3 vs. 4)		0.000	0.000
5. Firms with no significant IB and no significant brokerage business	246	16.58	15
6. Firms with significant brokerage but with no significant IB business	246	17.83	15
p-value of t-test/signed-rank test (5 vs. 6)		0.014	0.001
7. Firms with no significant IB and no significant brokerage business	52	19.40	20
8. Firms with significant IB but no significant brokerage business	52	21.66	20
p-value of t-test/signed-rank test (7 vs. 8)		0.033	0.016

Table 7
Analysis of Long-Term Earnings Growth Forecasts

This table reports coefficient estimates from regressions explaining the level of long-term earnings growth (LTG) forecasts made over the January 1994-June 2003 period. The sample period is partitioned into calendar quarters ending March, June, September and December. The sample includes only the latest forecast made in a quarter by an analyst for a company. The Fama-MacBeth regressions include unreported industry dummies. In the fixed-effects regressions, company-year-quarter effects are treated as fixed. Revenue data are obtained from x-17a-5 or 10-K filings with the U.S. Securities and Exchange Commission. Each forecasting period is matched with broker-dealer revenue data corresponding to the latest fiscal year preceding the date of the forecast. Company-specific and general forecasting experience are measured as the number of years since an analyst first began issuing I/B/E/S EPS forecasts on a particular company or in general. The number of analysts employed by a firm, the number of companies covered by an analyst, and the number of industry groups covered by an analyst are measured over the calendar year of the earnings forecast. Industry groupings are based on I/B/E/S 4-digit S/I/G codes. Company market capitalization is measured in millions of dollars one year prior to quarter-end. The public brokerage dummy equals unity if a broker-dealer is traded on NYSE, AMEX, or Nasdaq and equals zero otherwise. T-statistics for coefficient estimates are in parentheses.

	Fama-MacBeth (1)		**Company-Quarter Fixed Effects (2)**	
Constant	20.17 (3.16)[a]	17.33 (2.37)[b]	21.54 (28.87)[a]	21.58 (28.64)[a]
IB revenue as fraction of total revenue	3.53 (0.29)	8.86 (0.61)	0.151 (0.14)	0.158 (0.15)
Commission revenue as fraction of total revenue	6.68 (0.64)	-2.16 (-0.68)	1.27 (2.39)[b]	1.257 (2.37)[b]
Ln (1+Number of analysts employed by brokerage)	-0.498 (-0.65)	-0.22 (-0.27)	-0.516 (-3.61)[a]	-0.543 (-3.28)[a]
Company-specific forecasting experience	-0.649 (-17.03)[a]	-0.65 (-16.90)[a]	0.026 (0.78)	0.026 (0.79)
General forecasting experience	-0.003 (-0.08)	-0.005 (-0.15)	-0.005 (-0.26)	-0.005 (-0.27)
Number of companies followed	-0.032 (-2.05)[b]	-0.034 (-2.11)[b]	-0.007 (-0.73)	-0.007 (-0.74)
Number of industry groups followed	0.185 (3.03)[a]	0.185 (2.97)[a]	0.035 (0.54)	0.035 (0.54)
Public broker-dealer dummy		3.459 (1.05)		0.090 (0.32)
Number of Observations	35258	35258	35319	35319
Number of Groups			26870	26870
R^2	0.008	0.008	0.007	0.007

[a,b] denote statistical significance in 2-tailed tests at the 1% and 5% levels, respectively.

Table 8
Analysis of Quarterly Earnings Forecast Frequency

The dependent variable in the OLS and Poisson regressions in columns (1) and (3) is the number of EPS forecasts issued by an individual analyst on a given company during the three months preceding the end of the quarter. The dependent variable in the logistic regressions in column (2) is an indicator variable equal to one if an analyst issued more than one forecast during the three-month forecasting period, and equal to zero otherwise. The sample consists of quarterly EPS forecasts made over the January 1994-June 2003 period. Company quarters not ending March, June, September, or December are excluded from the analysis. Regressions are performed on the pooled sample of observations and include unreported industry and calendar-quarter dummies. Revenue data from x-17a-5 or 10-K filings with the U.S. Securities and Exchange Commission are used to construct a variable measuring the potential degree of analysts' conflict of interest. Each forecast period is matched with broker-dealer revenue data corresponding to the latest fiscal year ending before the forecast period. Company-specific and general forecasting experience are measured as the number of years since an analyst first began issuing EPS forecasts through I/B/E/S on a particular company or in general. The number of analysts employed by a firm, the number of companies covered by an analyst, and the number of industry groups covered by an analyst are measured over the calendar year of the earnings forecast. Industry groupings are based on I/B/E/S 4-digit S/I/G codes. Company market capitalization is measured in millions of dollars one year prior to quarter-end. The public brokerage dummy equals unity if a broker-dealer is traded on NYSE, AMEX, or Nasdaq and equals zero otherwise. Heteroskedasticity-consistent t-statistics and z-statistics are in parentheses.

	OLS Specification (1)		**Logistic Specification (2)**		**Poisson Specification (3)**	
Constant	1.4321 (17.29)[a]	1.4324 (17.29)[a]	-0.9397 (-3.38)[a]	-2.2965 (-6.37)[a]	0.3521 (5.94)[a]	0.0784 (1.32)
Commission revenue as fraction of total revenue	0.0606 (6.75)[a]	0.0607 (6.77)[a]	0.2008 (5.49)[a]	0.1995 (5.46)[a]	0.0465 (6.81)[a]	0.0467 (6.84)[a]
Ln (1+Number of analysts employed by brokerage)	0.0140 (6.67)[a]	0.0121 (4.79)[a]	0.0838 (9.56)[a]	0.0895 (8.56)[a]	0.0114 (7.11)[a]	0.0101 (5.27)[a]
Company-specific forecasting experience	0.0088 (12.51)[a]	0.0088 (12.53)[a]	0.0265 (10.75)[a]	0.0265 (10.71)[a]	0.0062 (12.12)[a]	0.0062 (12.14)[a]
General forecasting experience	-0.0015 (-3.24)[a]	-0.0016 (-3.29)[a]	-0.0049 (-2.63)[a]	-0.0049 (-2.59)[a]	-0.0011 (-3.16)[a]	-0.0011 (-3.20)[a]
Number of companies followed	0.0011 (6.39)[a]	0.0011 (6.39)[a]	0.0042 (5.70)[a]	0.0042 (5.70)[a]	0.0009 (6.64)[a]	0.0009 (6.64)[a]
Number of industry groups followed	-0.0080 (-7.91)[a]	-0.0079 (-7.86)[a]	-0.0268 (-6.26)[a]	-0.0270 (-6.30)[a]	-0.0060 (-7.74)[a]	-0.0059 (-7.69)[a]
Ln (Market capitalization of company)	0.0291 (30.67)[a]	0.0291 (30.65)[a]	0.1071 (28.75)[a]	0.1072 (28.76)[a]	0.0222 (31.15)[a]	0.0221 (31.12)[a]
Public broker-dealer dummy		0.0077 (1.46)		-0.0230 (-1.00)		0.0052 (1.27)
Number of Observations	143474	143474	143474	143474	143474	143474
Model P-value	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
R^2	0.067	0.067	0.045	0.045	0.008	0.008

[a,b] denote statistical significance in 2-tailed tests at the 1% and 5% levels, respectively.

Appendix Table A.1
Firms Employing the Most Analysts for Fiscal Years Ending in 2002

Panel A: Largest Analyst Employers with No IB Business

Firm name	Number of Analysts	Total Revenue ($ millions)	Commission Revenue ($ millions)
Adams, Harkness, & Hill, Inc.	23	61.78	63.84
BB&T Capital Markets	21	52.31	9.01
SWS Securities	17	22.78	22.42
Buckingham Research	17	28.69	27.23

Panel B: Largest Analyst Employers with No Commission Revenue

Firm name	Number of Analysts	Total Revenue ($ millions)	IB Revenue ($ millions)
Paradigm Capital, Inc.	8	0.0017	0
Hudson River Analytics, Inc.	1	0.0014	0

Panel C: Largest Analyst Employers

Firm name	Number of Analysts	Total Revenue ($ millions)	IB Revenue ($ millions)	Commission Revenue ($ millions)
Merrill Lynch & Co., Inc.	231	18,608	2,413	4,657
Morgan Stanley, Dean Witter & Co.	199	32,415	2,527	3,280
Salomon Smith Barney Holdings, Inc.	139	21,250	3,420	3,845
Goldman Sachs & Co.	133	22,854	2,572	4,950
Bear Stearns & Co.	122	6,891	833	1,110

CHAPTER 18

The Valuation of Common Stocks

In Chapter 17 it was noted that one purpose of financial analysis is to identify mispriced securities. Fundamental analysis was mentioned as one approach for conducting a search for such securities. With this approach the security analyst makes estimates of such things as the firm's future earnings and dividends. If these estimates are substantially different from the average estimates of other analysts but are felt to be more accurate, then from the viewpoint of the security analyst, a mispriced security will have been identified. If it is also felt that the market price of the security will adjust to reflect these more accurate estimates, then the security will be expected to have an abnormal rate of return. Accordingly, the analyst will issue either a buy or sell recommendation, depending on the direction of the anticipated price adjustment. Based on the capitalization of income method of valuation, dividend discount models have been frequently used by fundamental analysts as a means of identifying mispriced stocks. This chapter will discuss dividend discount models and how they can be related to models based on price-earnings ratios.

18.1 CAPITALIZATION OF INCOME METHOD OF VALUATION

There are many ways to implement the fundamental analysis approach to identifying mispriced securities. A number of them are either directly or indirectly related to what is sometimes referred to as the **capitalization of income method of valuation.**[1] This method states that the "true" or "intrinsic" value of any asset is based on the cash flows that the investor expects to receive in the future from owning the asset. Because these cash flows are expected in the future, they are adjusted by a **discount rate** to reflect not only the time value of money but also the riskiness of the cash flows.

Algebraically, the intrinsic value of the asset V is equal to the sum of the present values of the expected cash flows:

$$\begin{aligned} V &= \frac{C_1}{(1+k)^1} + \frac{C_2}{(1+k)^2} + \frac{C_3}{(1+k)^3} + \cdots \\ &= \sum_{t=1}^{\infty} \frac{C_t}{(1+k)^t} \end{aligned} \tag{18.1}$$

where C_t denotes the expected cash flow associated with the asset at time t and k is the appropriate discount rate for cash flows of this degree of risk. In this equation the discount rate is assumed to be the same for all periods. Because the symbol ∞ above the summation sign in the equation denotes infinity, all expected cash flows, from immediately after making the investment until infinity, will be discounted at the same rate in determining V.[2]

18.1.1 Net Present Value

For the sake of convenience, let the current moment in time be denoted as zero, or $t = 0$. If the cost of purchasing an asset at $t = 0$ is P, then its **net present value** (NPV) is equal to the difference between its intrinsic value and cost, or:

$$\begin{aligned} \text{NPV} &= V - P \\ &= \left[\sum_{t=1}^{\infty} \frac{C_t}{(1+k)^t}\right] - P. \end{aligned} \tag{18.2}$$

The NPV calculation shown here is conceptually the same as the NPV calculation made for capital budgeting decisions that has long been advocated in introductory finance textbooks. Capital budgeting decisions involve deciding whether or not a given investment project should be undertaken. (For example, should a new machine be purchased?) In making this decision, the focal point is the NPV of the project. Specifically, an investment project is viewed favorably if its NPV is positive, and unfavorably if its NPV is negative. For a simple project involving a cash outflow now (at $t = 0$) and expected cash inflows in the future, a positive NPV means that the present value of all the expected cash inflows is greater than the cost of making the investment. Conversely, a negative NPV means that the present value of all the expected cash inflows is less than the cost of making the investment.

The same views about NPV apply when financial assets (such as a share of common stock), instead of real assets (such as a new machine), are being considered for purchase. That is, a financial asset is viewed favorably and said to be underpriced (or undervalued) if NPV > 0. Conversely, a financial asset is viewed unfavorably and said to be overpriced or (overvalued) if NPV < 0. From Equation (18.2), this is equivalent to stating that a financial asset is underpriced if $V > P$:

$$\sum_{t=1}^{\infty} \frac{C_t}{(1+k)^t} > P. \tag{18.3}$$

Conversely, the asset is overvalued if $V < P$:

$$\sum_{t=1}^{\infty} \frac{C_t}{(1+k)^t} < P.$$

18.1.2 Internal Rate of Return

Another way of making capital budgeting decisions in a manner that is similar to the NPV method involves calculating the **internal rate of return** (IRR) associated with the investment project. With IRR, NPV in Equation (18.2) is set equal to zero and the discount rate becomes the unknown that must be calculated. That is, the IRR for a given investment is the discount rate that makes the NPV of the investment equal to zero. Algebraically, the procedure involves solving the following equation for the internal rate of return k^*:

$$0 = \sum_{t=1}^{\infty} \frac{C_t}{(1+k^*)^t} - P. \tag{18.5}$$

Equivalently, Equation (18.5) can be rewritten as:

$$P = \sum_{t=1}^{\infty} \frac{C_t}{(1+k^*)^t}. \tag{18.6}$$

The decision rule for IRR involves comparing the project's IRR (denoted by k^*) with the required rate of return for an investment of similar risk (denoted by k). Specifically, the investment is viewed favorably if $k^* > k$, and unfavorably if $k^* < k$. As with NPV, the same decision rule applies if either a real asset or a financial asset is being considered for possible investment.[3]

18.1.3 Application to Common Stocks

This chapter is concerned with using the capitalization of income method to determine the intrinsic value of common stocks. Because the cash flows associated with an investment in any particular common stock are the dividends that are expected to be paid throughout the future on the shares purchased, the models suggested by this method of valuation are often known as **dividend discount models** (DDMs).[4] Accordingly, D_t will be used instead of C_t to denote the expected cash flow in period t associated with a particular common stock, resulting in the following restatement of Equation (18.1):

$$\begin{aligned} V &= \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots \\ &= \sum_{t=1}^{\infty} \frac{D_t}{(1+k)^t} \end{aligned} \tag{18.7}$$

Usually the focus of DDMs is on determining the "true" or "intrinsic" value of one share of a particular company's common stock, even if larger size purchases are being contemplated. This is because it is usually assumed that larger size purchases can be made at a cost that is a simple multiple of the cost of one share. (For example, the cost of 1,000 shares is usually assumed to be 1,000 times the cost of one share.) Thus the numerator in DDMs is the cash dividends per share that are expected in the future.

However, there is a complication in using Equation (18.7) to determine the intrinsic value of a share of common stock. In particular, in order to use this equation the investor must forecast *all* future dividends. Because a common stock does not have a fixed lifetime, this suggests that an infinitely long stream of dividends must be forecast. Although this may seem to be an impossible task, with the addition of certain assumptions, the equation can be made tractable (that is, usable).

These assumptions center on dividend growth rates. That is, the dividend per share at any time t can be viewed as being equal to the dividend per share at time $t - 1$ times a dividend growth rate of g_t,

$$D_t = D_{t-1}(1 + g_t) \tag{18.8}$$

or, equivalently:

$$\frac{D_t - D_{t-1}}{D_{t-1}} = g_t. \tag{18.9}$$

For example, if the dividend per share expected at $t = 2$ is \$4 and the dividend per share expected at $t = 3$ is \$4.20, then $g_3 = (\$4.20 - \$4)/\$4 = 5\%$.

The different types of tractable DDMs reflect different sets of assumptions about dividend growth rates, and are presented next. The discussion begins with the simplest case, the zero-growth model.

18.2 THE ZERO-GROWTH MODEL

One assumption that could be made about future dividends is that they will remain at a fixed dollar amount. That is, the dollar amount of dividends per share that were paid over the past year D_0 will also be paid over the next year D_1, and the year after that D_2, and the year after that D_3, and so on—that is,

$$D_0 = D_1 = D_2 = D_3 = \cdots = D_\infty.$$

This is equivalent to assuming that all the dividend growth rates are zero, because if $g_t = 0$, then $D_t = D_{t-1}$ in Equation (18.8). Accordingly, this model is often referred to as the **zero-growth** (or no-growth) **model.**

18.2.1 Net Present Value

The impact of this assumption on Equation (18.7) can be analyzed by noting what happens when D_t is replaced by D_0 in the numerator:

$$V = \sum_{t=1}^{\infty} \frac{D_0}{(1 + k)^t}. \tag{18.10}$$

Fortunately, Equation (18.10) can be simplified by noting that D_0 is a fi
lar amount, which means that it can be written outside the summation sig

$$V = D_0\left[\sum_{t=1}^{\infty} \frac{1}{(1+k)^t}\right]. \tag{18.11}$$

The next step involves using a property of infinite series from mathem
If $k > 0$, then it can be shown that:

$$\sum_{t=1}^{\infty} \frac{1}{(1+k)^t} = \frac{1}{k}. \tag{18.12}$$

Applying this property to Equation (18.11) results in the following formula
the zero-growth model:

$$V = \frac{D_0}{k_0}. \tag{18.13}$$

Because $D_0 = D_1$, Equation (18.13) is written sometimes as:

$$V = \frac{D_1}{k}. \tag{18.14}$$

Example

As an example of how this DDM can be used, assume that the Zinc Company is expected to pay cash dividends amounting to \$8 per share into the indefinite future and has a required rate of return of 10%. Using either Equation (18.13) or Equation (18.14), it can be seen that the value of a share of Zinc stock is equal to \$80 (= \$8/.10). With a current stock price of \$65 per share, Equation (18.2) would suggest that the NPV per share is \$15 (= \$80 − \$65). Equivalently, as $V = \$80 > P = \$65$, the stock is underpriced by \$15 per share and would be a candidate for purchase.

18.2.2 Internal Rate of Return

Equation (18.13) can be reformulated to solve for the IRR on an investment in a zero-growth security. First, the security's current price P is substituted for V, and second, k^* is substituted for k. These changes result in:

$$P = \frac{D_0}{k^*}$$

which can be rewritten as:

$$k^* = \frac{D_0}{P} \tag{18.15a}$$

$$= \frac{D_1}{P}. \tag{18.15b}$$

Example

Applying this formula to the stock of Zinc indicates that $k^* = 12.3\%$ (= \$8/\$65). Because the IRR from an investment in Zinc exceeds the required rate of return on Zinc ($12.3\% > 10\%$), this method also indicates that Zinc is underpriced.[5]

18.2.3 Application

The zero-growth model may seem quite restrictive. After all, it seems unreasonable to assume that a given stock will pay a fixed dollar-size dividend forever. Although such a criticism has validity for common stock valuation, there is one particular situation where this model is quite useful.

Specifically, whenever the intrinsic value of a share of high-grade preferred stock is to be determined, the zero-growth DDM will often be appropriate. This is because most preferred stock is nonparticipating, meaning that it pays a fixed dollar-size dividend that will not change as earnings per share change. Furthermore, for high-grade preferred stock these dividends are expected to be paid regularly into the foreseeable future. Why? Because preferred stock does not have a fixed lifetime, and, by restricting the application of the zero growth model to high-grade preferred stocks, the chance of a suspension of dividends is remote.[6]

18.3 THE CONSTANT-GROWTH MODEL

The next type of DDM to be considered is one that assumes that dividends will grow from period to period at the same rate forever, and is therefore known as the **constant growth model.**[7] Specifically, the dividends per share that were paid over the previous year D_0 are expected to grow at a given rate g, so that the dividends expected over the next year D_1 are expected to be equal to $D_0(1 + g)$. Dividends the year after that are again expected to grow by the same rate g, meaning that $D_2 = D_1(1 + g)$. Because $D_1 = D_0(1 + g)$, this is equivalent to assuming that $D_2 = D_0(1 + g)^2$ and, in general:

$$D_t = D_{t-1}(1 + g) \tag{18.16a}$$

$$= D_0(1 + g)^t. \tag{18.16b}$$

18.3.1 Net Present Value

The impact of this assumption on Equation (18.7) can be analyzed by noting what happens when D_t is replaced by $D_0(1 + g)^t$ in the numerator:

$$V = \sum_{t=1}^{\infty} \frac{D_0(1 + g)^t}{(1 + k)^t}. \tag{18.17}$$

Fortunately, Equation (18.17) can be simplified by noting that D_0 is a constant dollar amount, which means that it can be written outside the summation sign:

$$V = D_0\left[\sum_{t=1}^{\infty} \frac{(1+g)^t}{(1+k)^t}\right]. \tag{18.18}$$

The next step involves using a property of infinite series from mathematics. If $k > g$, then it can be shown that:

$$\sum_{t=1}^{\infty} \frac{(1+g)^t}{(1+k)^t} = \frac{1+g}{k-g}. \tag{18.19}$$

Substituting Equation (18.19) into Equation (18.18) results in the valuation formula for the constant-growth model:

$$V = D_0\left(\frac{1+g}{k-g}\right). \tag{18.20}$$

Sometimes Equation (18.20) is rewritten as:

$$V = \frac{D_1}{k-g} \tag{18.21}$$

because $D_1 = D_0(1 + g)$.

Example

As an example of how this DDM can be used, assume that during the past year the Copper Company paid dividends amounting to \$1.80 per share. The forecast is that dividends on Copper stock will increase by 5% per year into the indefinite future. Thus dividends over the next year are expected to equal \$1.89 [= \$1.80 × (1 + .05)]. Using Equation (18.20) and assuming a required rate of return k of 11%, it can be seen that the value of a share of Copper stock is equal to \$31.50 [= \$1.80 × (1 + .05)/(.11 − .05) = \$1.89/(.11 − .05)]. With a current stock price of \$40 per share, Equation (18.2) would suggest that the NPV per share is −\$8.50 (= \$31.50 − \$40). Equivalently, as V = \$31.50 < P = \$40, the stock is overpriced by \$8.50 per share and would be a candidate for sale if currently owned.

18.3.2 Internal Rate of Return

Equation (18.20) can be reformulated to solve for the IRR on an investment in a constant-growth security. First, the current price of the security P is substituted for V and then k^* is substituted for k. These changes result in:

$$P = D_0\left(\frac{1+g}{k^*-g}\right). \tag{18.22}$$

which can be rewritten as:

$$k^* = \frac{D_0(1 + g)}{P} + g \tag{18.23a}$$

$$= \frac{D_1}{P} + g. \tag{18.23b}$$

Example

Applying this formula to the stock of Copper indicates that $k^* = 9.72\%$ {= [\$1.80 × (1 + .05)/\$40] + .05 = (\$1.89/\$40) + .05}. Because the required rate of return on Copper exceeds the IRR from an investment in Copper (11% > 9.72%), this method also indicates that Copper is overpriced.

18.3.3 Relationship to the Zero-Growth Model

The zero-growth model of the previous section can be shown to be a special case of the constant-growth model. In particular, if the growth rate g is assumed to be equal to zero, then dividends will be a fixed dollar amount forever, which is the same as saying that there will be zero growth. Letting $g = 0$ in Equations (18.20) and (18.23a) results in two equations that are identical to Equations (18.13) and (18.15a), respectively.

Even though the assumption of constant dividend growth may seem less restrictive than the assumption of zero dividend growth, it may still be viewed as unrealistic in many cases. However, as will be shown next, the constant-growth model is important because it is embedded in the multiple-growth model.

18.4 THE MULTIPLE-GROWTH MODEL

A more general DDM for valuing common stocks is the **multiple-growth model.** With this model, the focus is on a time in the future (denoted by T) after which dividends are expected to grow at a constant rate g. Although the investor is still concerned with forecasting dividends, these dividends do not need to have any specific pattern until this time, after which they will be assumed to have the specific pattern of constant growth. The dividends up until T ($D_1, D_2, D_3, \ldots, D_T$) will be forecast individually by the investor. (The investor also forecasts when this time T will occur.) Thereafter dividends are assumed to grow by a constant rate g that the investor must also forecast, meaning that:

$$D_{T+1} = D_T(1 + g)$$
$$D_{T+2} = D_{T+1}(1 + g) = D_T(1 + g)^2$$
$$D_{T+3} = D_{T+2}(1 + g) = D_T(1 + g)^3$$

...on. Figure 18.1 presents a time line of dividends and growth rates associ-
...th the multiple-growth model.

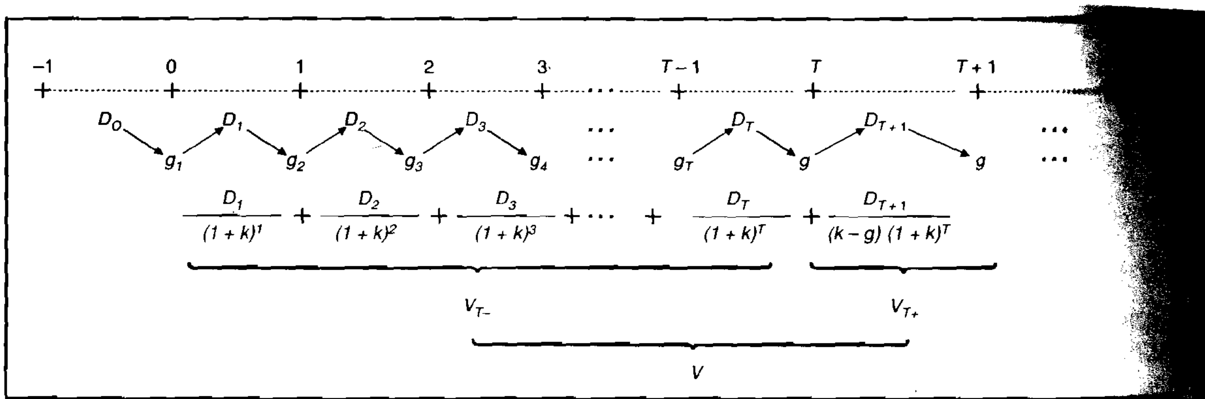


Figure 18.1
Time Line for Multiple-Growth Model

18.4.1 Net Present Value

In determining the value of a share of common stock with the multiple-growth model, the present value of the forecast stream of dividends must be determined. This can be done by dividing the stream into two parts, finding the present value of each part, and then adding these two present values together.

The first part consists of finding the present value of all the forecast dividends that will be paid up to and including time T. Denoting this present value by V_{T-}, it is equal to:

$$V_{T-} = \sum_{t=1}^{T} \frac{D_t}{(1 + k)^t}. \tag{18.24}$$

The second part consists of finding the present value of all the forecast dividends that will be paid after time T, and involves the application of the constant-growth model. The application begins by imagining that the investor is not at time zero but is at time T, and has not changed his or her forecast of dividends for the stock. This means that the next period's dividend D_{T+1} and all those thereafter are expected to grow at the rate g. Thus the investor would be viewing the stock as having a constant growth rate, and its value at time T, V_T, could be determined with the constant-growth model of Equation (18.21):

$$V_T = D_{T+1}\left(\frac{1}{k - g}\right). \tag{18.25}$$

One way to view V_T is that it represents a lump sum that is just as desirable as the stream of dividends after T. That is, an investor would find a lump sum of cash equal to V_T, to be received at time T, to be equally desirable as the stream of dividends D_{T+1}, D_{T+2}, D_{T+3}, and so on. Now given that the investor is at time zero, not at time T, the present value at $t = 0$ of the lump sum V_T must be determined. This is done simply by discounting it for T periods at the rate k, resulting in the following formula for finding the present value at time zero for all dividends after T, denoted V_{T+}:

$$V_{T+} = V_T\left[\frac{1}{(1+k)^T}\right] \tag{18.26}$$

$$= \frac{D_{T+1}}{(k-g)(1+k)^T}.$$

Having found the present value of all dividends up to and including time T with Equation (18.24), and the present value of all dividends after time T with Equation (18.26), the value of the stock can be determined by summing up these two amounts:

$$V = V_{T-} + V_{T+}$$

$$= \sum_{t=1}^{T} \frac{D_t}{(1+k)^t} + \frac{D_{T+1}}{(k-g)(1+k)^T}. \tag{18.27}$$

Figure 18.1 illustrates the valuation procedure for the multiple-growth DDM that is given in Equation (18.27).

Example

As an example of how this DDM can be used, assume that during the past year the Magnesium Company paid dividends amounting to \$.75 per share. Over the next year, Magnesium is expected to pay [illegible]

[illegible] $D_0)/D_0 = (\$2 - \$.75)/\$.75 = 167\%$. The year after that, dividends are expected to amount to \$3 per share, indicating that $g_2 = (D_2 - D_1)/D_1 = (\$3 - \$2)/\$2 = 50\%$. At this time, the forecast is that dividends will grow by 10% per year indefinitely, indicating that $T = 2$ and $g = 10\%$. Consequently, $D_{T+1} = D_3 = \$3(1 + .10) = \$3.30$. Given a required rate of return on Magnesium shares of 15%, the values of V_{T-} and V_{T+} can be calculated as follows:

$$V_{T-} = \frac{\$2}{(1+.15)^1} + \frac{\$3}{(1+.15)^2}$$

$$= \$4.01$$

$$V_{T+} = \frac{\$3.30}{(.15 - .10)(1+.15)^2}$$

$$= \$49.91.$$

...ing V_{T-} and V_{T+} results in a value for V of \$4.01 + \$49.91 = \$53.92. With ...ent stock price of \$55 per share, Magnesium appears to be fairly priced. ... Magnesium is not significantly mispriced because V and P are nearly of ...ze.

18.4.2 Internal Rate of Return

The zero-growth and constant-growth models have equations for V that reformulated in order to solve for the IRR on an investment in a stock. U-nately, a convenient expression similar to Equations (18.15a), (18.15b), (1 and (18.23b) is not available for the multiple-growth model. This can be s noting that the expression for IRR is derived by substituting P for V, and k^* in Equation (18.27):

$$P = \sum_{t=1}^{T} \frac{D_t}{(1 + k^*)^t} + \frac{D_{T+1}}{(k^* - g)(1 + k^*)^T}. \qquad (18.28)$$

This equation cannot be rewritten with k^* isolated on the left-hand side, mean-ing that a closed-form expression for IRR does not exist for the multiple-growth model.

However, all is not lost. It is still possible to calculate the IRR for an invest-ment in a stock conforming to the multiple-growth model by using an "educat-ed" trial-and-error method. The basis for this method is in the observation that the right-hand side of Equation (18.28) is simply equal to the present value of the dividend stream, where k^* is used as the discount rate. Hence the larger the value of k^*, the smaller the value of the right-hand side of Equation (18.28). The trial-and-error method proceeds by initially using an estimate for k^*. If the result-ing value on the right-hand side of Equation (18.28) is larger than P, then a larg-er estimate of k^* is tried. Conversely, if the resulting value is smaller than P, then a smaller estimate of k^* is tried. Continuing this search process, the investor can hone in on the value of k^* that makes the right-hand side equal P on the left-hand side. Fortunately, it is a relatively simple matter to program a computer to conduct the search for k^* in Equation (18.28). Most spreadsheets include a func-tion that does so automatically.

Example

Applying Equation (18.28) to the Magnesium Company results in:

$$\$55 = \frac{\$2}{(1 + k^*)^1} + \frac{\$3}{(1 + k^*)^2} + \frac{\$3.30}{(k^* - .10)(1 + k^*)^2}. \qquad (18.29)$$

Initially a rate of 14% is used in attempting to solve this equation for k^*. Inserting 14% for k^* in the right-hand side of Equation (18.29) results in a value of \$67.54. Earlier 15% was used in determining V and resulted in a value of \$53.92. This means that k^* must have a value between 14% and 15%, since \$55 is between \$67.54 and \$53.92. If 14.5% is tried next, the resulting value is \$59.97, suggesting that a higher rate should be tried. If 14.8% and 14.9% are subsequently tried, the respective resulting values are \$56.18 and \$55.03. As \$55.03 is the closest to P, the IRR associated with an investment in Magnesium is 14.9%. Given a required return of 15% and an IRR of approximately that amount, the stock of Magnesium appears to be fairly priced.

18.4.3 Relationship to the Constant-Growth Model

The constant-growth model can be shown to be a special case of the multiple-growth model. In particular, if the time when constant growth is assumed to begin is set equal to zero, then:

$$V_{T-} = \sum_{t=1}^{T} \frac{D_t}{(1 + k)^t} = 0$$

and

$$V_{T+} = \frac{D_{T+1}}{(k - g)(1 + k)^T} = \frac{D_1}{k - g}$$

because $T = 0$ and $(1 + k)^0 = 1$. Given that the multiple-growth model states that $V = V_{T-} + V_{T+}$, it can be seen that setting $T = 0$ results in $V = D_1/(k - g)$, a formula that is equivalent to the formula for the constant-growth model.

18.4.4 Two-Stage and Three-Stage Models

Two dividend discount models that investors sometimes use are the two-stage model and the three-stage model.[8] The two-stage model assumes that a constant growth rate g_1 exists only until some time T, when a different growth rate g_2 is assumed to begin and continue thereafter. The three-stage model assumes that a constant growth rate g_1 exists only until some time T_1, when a second growth rate is assumed to begin and last until a later time T_2, when a third growth rate is assumed to begin and last thereafter. By letting V_{T+} denote the present value of all dividends after the last growth rate has begun and V_{T-} the present value of all the preceding dividends, it can be seen that these models are just special cases of the multiple-growth model.

In applying the capitalization of income method of valuation to common stocks, it might seem appropriate to assume that the stock will be sold at some point in the future. In this case the expected cash flows would consist of the dividends up to that point as well as the expected selling price. Because dividends after the selling date would be ignored, the use of a dividend discount model may seem to be improper. However, as will be shown next, this is not so.

18.5 VALUATION BASED ON A FINITE HOLDING PERIOD

capitalization of income method of valuation involves discounting all divi-
that are expected throughout the future. Because the simplified models
growth, constant growth, and multiple growth are based on this method,
involve a future stream of dividends. Upon reflection it may seem that
odels are relevant only for an investor who plans to hold a stock forever,
uch an investor would expect to receive this stream of future dividends.

But what about an investor who plans to sell the stock in a year? In this situation, the cash flows that the investor expects to receive from purchasing a share of the stock are equal to the dividend expected to be paid one year from now (for ease of exposition, it is assumed that common stocks pay dividends annually) and the expected selling price of the stock. Thus it would seem appropriate to determine the intrinsic value of the stock to the investor by discounting these two cash flows at the required rate of return as follows:

$$
\begin{aligned}
V &= \frac{D_1 + P_1}{1 + k} \\
&= \frac{D_1}{1 + k} + \frac{P_1}{1 + k}
\end{aligned}
\tag{18.30}
$$

where D_1 and P_1 are the expected dividend and selling price at $t = 1$, respectively.

In order to use Equation (18.30), the expected price of the stock at $t = 1$ must be estimated. The simplest approach assumes that the selling price will be based on the dividends that are expected to be paid after the selling date. Thus the expected selling price at $t = 1$ is:

$$
\begin{aligned}
P_1 &= \frac{D_2}{(1 + k)^1} + \frac{D_3}{(1 + k)^2} + \frac{D_4}{(1 + k)^3} + \cdots \\
&= \sum_{t=2}^{\infty} \frac{D_t}{(1 + k)^{t-1}}.
\end{aligned}
\tag{18.31}
$$

Substituting Equation (18.31) for P_1 in the right-hand side of Equation (18.30) results in:

$$
\begin{aligned}
V &= \frac{D_1}{1 + k} + \left[\frac{D_2}{(1 + k)^1} + \frac{D_3}{(1 + k)^2} + \frac{D_4}{(1 + k)^3} + \cdots\right]\left(\frac{1}{1 + k}\right) \\
&= \frac{D_1}{(1 + k)^1} + \frac{D_2}{(1 + k)^2} + \frac{D_3}{(1 + k)^3} + \frac{D_4}{(1 + k)^4} + \cdots \\
&= \sum_{t=1}^{\infty} \frac{D_t}{(1 + k)^t}
\end{aligned}
$$

which is exactly the same as Equation (18.7). Thus valuing a share of common stock by discounting its dividends up to some point in the future and its expected selling price at that time is equivalent to valuing stock by discounting all future dividends. Simply stated, the two are equivalent because the expected selling price is itself based on dividends to be paid after the selling date. Thus Equation (18.7), as well as the zero-growth, constant-growth, and multiple-growth models that are based on it, is appropriate for determining the intrinsic value of a share of common stock regardless of the length of the investor's planned holding period.

Example

As an example, reconsider the common stock of the Copper Company. Over the past year it was noted that Copper paid dividends of $1.80 per share, with the forecast that the dividends would grow by 5% per year forever. This means that dividends over the next two years (D_1 and D_2) are forecast to be \$1.89 [= \$1.80 $\times$ (1 + .05)] and \$1.985 [= \$1.89 $\times$ (1 + .05)], respectively. If the investor plans to sell the stock after one year, the selling price could be estimated by noting that at t = 1, the forecast of dividends for the forthcoming year would be D_2, or \$1.985. Thus the anticipated selling price at t = 1, denoted P_1, would be equal to \$33.08 [= \$1.985/(.11 − .05)]. Accordingly, the intrinsic value of Copper to such an investor would equal the present value of the expected cash flows, which are D_1 = \$1.89 and P_1 = \$33.08. Using Equation (18.30) and assuming a required rate of 11%, this value is equal to \$31.50 [= (\$1.89 + \$33.08)/(1 + .11)]. Note that this is the same amount that was calculated earlier when all the dividends from now to infinity were discounted using the constant-growth model: $V = D_1/(k - g)$ = \$1.89/(.11 − .05) = \$31.50.

18.6 MODELS BASED ON PRICE-EARNINGS RATIOS

Despite the inherent sensibility of DDMs, many security analysts use a much simpler procedure to value common stocks. First, a stock's earnings per share over the forthcoming year E_1 are estimated, and then the analyst (or someone else) specifies a "normal" **price-earnings ratio** for the stock. The product of these two numbers gives the estimated future price P_1. Together with estimated dividends D_1 to be paid during the period and the current price P, the estimated return on the stock over the period can be determined:

$$\text{Expected return} = \frac{(P_1 - P) + D_1}{P} \tag{18.32}$$

where $P_1 = (P_1/E_1) \times E_1$.

Some security analysts expand this procedure, estimating earnings per share and price-earnings ratios for optimistic, most likely, and pessimistic scenarios to produce a rudimentary probability distribution of a security's return. Other analysts determine whether a stock is underpriced or overpriced by comparing the stock's actual price-earnings ratio with its "normal" price-earnings ratio, as will be shown next.[10]

In order to make this comparison, Equation (18.7) must be rearranged and new variables introduced. To begin, it should be noted that earnings per share E_t are related to dividends per share D_t by the firm's **payout ratio** p_t,

$$D_t = p_t E_t. \tag{18.33}$$

...more, if an analyst has forecast earnings-per-share and payout ratios, ...she has implicitly forecast dividends.

...ion (18.33) can be used to restate the various DDMs where the focus is ...ing what the stock's price-earnings ratio should be instead of on esti... intrinsic value of the stock. In order to do so, $p_t E_t$ is substituted for D_t

in the right-hand side of Equation (18.7), resulting in a general formula for determining a stock's intrinsic value that involves discounting earnings:

$$
\begin{aligned}
V &= \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots \\
&= \frac{p_1 E_1}{(1+k)^1} + \frac{p_2 E_2}{(1+k)^2} + \frac{p_3 E_3}{(1+k)^3} + \cdots \\
&= \sum_{t=1}^{\infty} \frac{p_t E_t}{(1+k)^t}.
\end{aligned}
\tag{18.34}
$$

Earlier it was noted that dividends in adjacent time periods could be viewed as being "linked" to each other by a dividend growth rate g_t. Similarly, earnings per share in any year t can be "linked" to earnings per share in the previous year $t-1$ by a growth rate in earnings per share, g_{et},

$$E_t = E_{t-1}(1 + g_{et}). \tag{18.35}$$

This implies that

$$
\begin{aligned}
E_1 &= E_0(1 + g_{e1}) \\
E_2 &= E_1(1 + g_{e2}) = E_0(1 + g_{e1})(1 + g_{e2}) \\
E_3 &= E_2(1 + g_{e3}) = E_0(1 + g_{e1})(1 + g_{e2})(1 + g_{e3})
\end{aligned}
$$

and so on, where E_0 is the actual level of earnings per share over the past year, E_1 is the expected level of earnings per share over the forthcoming year, E_2 is the expected level of earnings per share for the year after E_1, and E_3 is the expected level of earnings per share for the year after E_2.

These equations relating expected future earnings per share to E_0 can be substituted into Equation (18.34), resulting in:

$$
\begin{aligned}
V = {} & \frac{p_1[E_0(1 + g_{e1})]}{(1+k)^1} + \frac{p_2[E_0(1 + g_{e1})(1 + g_{e2})]}{(1+k)^2} \\
& + \frac{p_3[E_0(1 + g_{e1})(1 + g_{e2})(1 + g_{e3})]}{(1+k)^3} + \cdots.
\end{aligned}
\tag{18.36}
$$

As V is the intrinsic value of a share of stock, it represents what the stock would be selling for if it were fairly priced. It follows that V/E_0 represents what the price-earnings ratio would be if the stock were fairly priced, and is sometimes referred to as the stock's "normal" price-earnings ratio. Dividing both sides of Equation (18.36) by E_0 and simplifying results in the formula for determining the "normal" price-earnings ratio:

$$
\begin{aligned}
\frac{V}{E_0} = {} & \frac{p_1(1 + g_{e1})}{(1+k)^1} + \frac{p_2(1 + g_{e1})(1 + g_{e2})}{(1+k)^2} \\
& + \frac{p_3(1 + g_{e1})(1 + g_{e2})(1 + g_{e3})}{(1+k)^3} + \cdots.
\end{aligned}
\tag{18.37}
$$

This shows that, other things being equal, a stock's "normal" price-earnings ratio will be higher:

The *greater* the expected payout ratios ($p_1, p_2, p_3, \ldots$),
The *greater* the expected growth rates in earnings per share ($g_{e1}, g_{e2}, g_{e3}, \ldots$),
The *smaller* the required rate of return (k).

The qualifying phrase "other things being equal" should not be overlooked. For example, a firm cannot increase the value of its shares by simply making greater payouts. This will increase $p_1, p_2, p_3, \ldots$, but will decrease the expected growth rates in earnings per share $g_{e1}, g_{e2}, g_{e3}, \ldots$. Assuming that the firm's investment policy is not altered, the effects of the reduced growth in its earnings per share will just offset the effects of the increased payouts, leaving its share value unchanged.

Earlier it was noted that a stock was viewed as underpriced if $V > P$ and overpriced if $V < P$. Because dividing both sides of an inequality by a positive constant will not change the direction of the inequality, such a division can be done here to the two inequalities involving V and P, where the positive constant is E_0. The result is that a stock can be viewed as being underpriced if $V/E_0 > P/E_0$ and overpriced if $V/E_0 < P/E_0$. Thus a stock will be underpriced if its "normal" price-earnings ratio is greater than its actual price-earnings ratio, and overpriced if its "normal" price-earnings ratio is less than its actual price-earnings ratio.

Unfortunately, Equation (18.37) is intractable, meaning that it cannot be used to estimate the "normal" price-earnings ratio for any stock. However, simplifying assumptions can be made that result in tractable formulas for estimating "normal" price-earnings ratios. These assumptions, along with the formulas, parallel those made previously regarding dividends and are discussed next.

18.6.1 The Zero-Growth Model

The zero-growth model assumed that dividends per share remained at a fixed dollar amount forever. This is most likely if earnings per share remain at a fixed dollar amount forever, with the firm maintaining a 100% payout ratio. Why 100%? Because if a lesser amount were assumed to be paid out, it would mean that the firm was retaining part of its earnings. These retained earnings would be put to some use, and would thus be expected to increase future earnings and hence dividends per share.

Accordingly, the zero-growth model can be interpreted as assuming $p_t = 1$ for all time periods and $E_0 = E_1 = E_2 = E_3$ and so on. This means that $D_0 = E_0$ = $D_1 = E_1 = D_2 = E_2$ and so on, allowing valuation Equation (18.13) to be restated as:

$$V = \frac{E_0}{k}. \tag{18.38}$$

Dividing Equation (18.38) by E_0 results in the formula for the "normal" price-earnings ratio for a stock having zero growth:

$$\frac{V}{E_0} = \frac{1}{k}. \tag{18.39}$$

Example

Earlier it was assumed that the Zinc Company was a zero-growth firm idends of $8 per share, selling for $65 a share, and having a required turn of 10%. Because Zinc is a zero-growth company, it will be assum has a 100% payout ratio which, in turn, means that E_0 = $8. At this po tion (18.38) can be used to note that a "normal" price-earnings ratio for $1/.10 = 10$. As Zinc has an actual price-earnings ratio of $65/$8 = 8.1, cause $V/E_0 = 10 > P/E_0 = 8.1$, it can be seen that Zinc stock is underpric

18.6.2 The Constant-Growth Model

Earlier it was noted that dividends in adjacent time periods could be viewed being connected to each other by a dividend growth rate g_t. Similarly, it noted that earnings per share can be connected by an earnings growth rate The constant-growth model assumes that the growth rate in dividends per share will be the same throughout the future. An equivalent assumption is that earnings per share will grow at a constant rate g_e throughout the future, with the payout ratio remaining at a constant level p. This means that:

$$
\begin{aligned}
E_1 &= E_0(1 + g_e) = E_0(1 + g_e)^1 \\
E_2 &= E_1(1 + g_e) = E_0(1 + g_e)(1 + g_e) = E_0(1 + g_e)^2 \\
E_3 &= E_2(1 + g_e) = E_0(1 + g_e)(1 + g_e)(1 + g_e) = E_0(1 + g_e)^3
\end{aligned}
$$

and so on. In general, earnings in year t can be connected to E_0 as follows:

$$E_t = E_0(1 + g_e)^t. \qquad (18.40)$$

Substituting Equation (18.40) into the numerator of Equation (18.34) and recognizing that $p_t = p$ results in:

$$
\begin{aligned}
V &= \sum_{t=1}^{\infty} \frac{pE_0(1 + g_e)^t}{(1 + k)^t} \\
&= pE_0\left[\sum_{t=1}^{\infty} \frac{(1 + g_e)^t}{(1 + k)^t}\right]. \qquad (18.41)
\end{aligned}
$$

The same mathematical property of infinite series given in Equation (18.19) can be applied to Equation (18.41), resulting in:

$$V = pE_0\left(\frac{1 + g_e}{k - g_e}\right). \qquad (18.42)$$

It can be noted that the earnings-based constant-growth model has a numerator that is identical to the numerator of the dividend-based constant-growth model, because $pE_0 = D_0$. Furthermore, the denominators of the two models are identical. Both assertions require that the growth rates in earnings and dividends be the same (that is, $g_e = g$). Examination of the assumptions of the models reveals that these growth rates must be equal. This can be seen by recalling that constant earnings growth means:

$$E_t = E_{t-1}(1 + g_e).$$

Now when both sides of this equation are multiplied by the constant payout ratio, the result is:

$$pE_t = pE_{t-1}(1 + g_e).$$

Because $pE_t = D_t$ and $pE_{t-1} = D_{t-1}$, this equation reduces to:

$$D_t = D_{t-1}(1 + g_e)$$

which indicates that dividends in any period $t - 1$ will grow by the earnings growth rate, g_e. Because the dividend-based constant-growth model assumed that dividends in any period $t - 1$ would grow by the dividend growth rate g, it can be seen that the two growth rates must be equal for the two models to be equivalent.

Equation (18.42) can be restated by dividing each side by E_0, resulting in the following formula for determining the "normal" price-earnings ratio for a stock with constant growth:

$$\frac{V}{E_0} = p\left(\frac{1 + g_e}{k + g_e}\right). \tag{18.43}$$

Example

Earlier it was assumed that the Copper Company had paid dividends of \$1.80 per share over the past year, with a forecast that dividends would grow by 5% per year forever. Furthermore, it was assumed that the required rate of return on Copper was 11%, and the current stock price was \$40 per share. Now assuming that E_0 was \$2.70, it can be seen that the payout ratio was equal to 66⅔% (= \$1.80/\$2.70). This means that the "normal" price-earnings ratio for Copper, according to Equation (18.43), is equal to 11.7 [= .6667 × (1 + .05) /(.11 −.05)]. Because this is less than Copper's actual price-earnings ratio of 14.8 (= \$40/\$2.70), it follows that the stock of Copper Company is overpriced.

18.6.3 The Multiple-Growth Model

Earlier it was noted that the most general DDM is the multiple-growth model, where dividends are allowed to grow at varying rates until some point in time T, after which they are assumed to grow at a constant rate. In this situation the present value of all the dividends is found by adding the present value of all dividends up to and including T, denoted by V_{T-}, and the present value of all dividends after T, denoted by V_{T+}:

$$\begin{aligned} V &= V_{T-} + V_{T+} \\ &= \sum_{t=1}^{T} \frac{D_t}{(1 + k)^t} + \frac{D_{T+1}}{(k - g)(1 + k)^T}. \end{aligned} \tag{18.27}$$

In general, earnings per share in any period t can be expressed as equal to E_0 times the product of all the earnings growth rates from time zero to time t:

$$E_t = E_0(1 + g_{e1})(1 + g_{e2}) \cdots (1 + g_{et}). \tag{18.44}$$

Because dividends per share in any period t are equal to the payout ratio for that period times the earnings per share, it follows from Equation (18.44) that:

$$\begin{aligned} D_t &= p_t E_t \\ &= p_t E_0(1 + g_{e1})(1 + g_{e2}) \cdots (1 + g_{et}). \end{aligned} \tag{18.45}$$

Replacing the numerator in Equation (18.37) with the right-hand side of Equation (18.45) and then dividing both sides by E_0 gives the following formula for determining a stock's "normal" price-earnings ratio with the multiple-growth model:

$$\begin{aligned} \frac{V}{E_0} &= \frac{p_1(1 + g_{e1})}{(1 + k)^1} + \frac{p_2(1 + g_{e1})(1 + g_{e2})}{(1 + k)^2} + \cdots \\ &\quad + \frac{p_T(1 + g_{e1})(1 + g_{e2}) \cdots (1 + g_{eT})}{(1 + k)^T} \\ &\quad + \frac{p(1 + g_{e1})(1 + g_{e2}) \cdots (1 + g_{eT})(1 + g)}{(k - g)(1 + k)^T}. \end{aligned} \tag{18.46}$$

Example

Consider the Magnesium Company again. Its share price is currently \$55, and per share earnings and dividends over the past year were \$3 and \$.75, respectively. For the next two years, forecast earnings and dividends, along with the earnings growth rates and payout ratios, are:

$$\begin{array}{llll} D_1 = \$2.00 & E_1 = \$5.00 & g_{e1} = 67\% & p_1 = 40\% \\ D_2 = \$3.00 & E_2 = \$6.00 & g_{e2} = 20\% & p_2 = 50\%. \end{array}$$

Constant growth in dividends and earnings of 10% per year is forecast to begin at $T = 2$, which means that $D_3 = \$3.30$, $E_3 = \$6.60$, $g = 10\%$, and $p = 50\%$.

Given a required return of 15%, Equation (18.46) can be used as follows to estimate a "normal" price-earnings ratio for Magnesium:

$$\begin{aligned} \frac{V}{E_0} &= \frac{.40(1 + .67)}{(1 + .15)^1} + \frac{.50(1 + .67)(1 + .20)}{(1 + .15)^2} + \frac{.50(1 + .67)(1 + .20)(1 + .10)}{(.15 - .10)(1 + .15)^2} \\ &= .58 + .76 + 16.67 \\ &= 18.01. \end{aligned}$$

Because the actual price-earnings ratio of 18.33 (= \$55/\$3) is close to the "normal" ratio of 18.01, the stock of the Magnesium Company can be viewed as fairly priced.

18.7 SOURCES OF EARNINGS GROWTH

So far no explanation has been given as to why earnings or dividends will be expected to grow in the future. One way of providing such an explanation uses the constant-growth model. Assuming that no new capital is obtained externally and no shares are repurchased (meaning that the number of shares outstanding does not increase or decrease), the portion of earnings not paid to stockholders as dividends will be used to pay for the firm's new investments. Given that p_t denotes the payout ratio in year t, then $(1 - p_t)$ will be equal to the portion of earnings not paid out, known as the **retention ratio.** Furthermore, the firm's new investments, stated on a per-share basis and denoted by I_t, will be:

$$I_t = (1 - p_t)E_t. \tag{18.47}$$

If these new investments have an average return on equity of r_t in period t and every year thereafter, they will add $r_t I_t$ to earnings per share in year $t + 1$ and every year thereafter. If all previous investments also produce perpetual earnings at a constant rate of return, next year's earnings will equal this year's earnings plus the new earnings resulting from this year's new investments:

$$\begin{aligned} E_{t+1} &= E_t + r_t I_t \\ &= E_t + r_t(1 - p_t)E_t \\ &= E_t[1 + r_t(1 - p_t)]. \end{aligned} \tag{18.48}$$

Because it was shown earlier that the growth rate in earnings per share is:

$$E_t = E_{t-1}(1 + g_{et}) \tag{18.35}$$

it follows that:

$$E_{t+1} = E_t(1 + g_{et+1}). \tag{18.49}$$

A comparison of Equations (18.48) and (18.49) indicates that:

$$g_{et+1} = r_t(1 - p_t). \tag{18.50}$$

If the growth rate in earnings per share g_{et+1} is to be constant over time, then the average return on equity for new investments r_t and the payout ratio p_t must also be constant over time. In this situation Equation (18.50) can be simplified by removing the time subscripts:

$$g_e = r(1 - p). \tag{18.51a}$$

Because the growth rate in dividends per share g is equal to the growth rate in earnings per share g_e, this equation can be rewritten as:

$$g = r(1 - p). \tag{18.51b}$$

From this equation it can be seen that the growth rate g depends on (1) the proportion of earnings that is retained $1 - p$, and (2) the average return on equity on the earnings that are retained r.

The constant-growth valuation formula given in Equation (18.20) can be modified by replacing g with the expression on the right-hand side of Equation (18.51b), resulting in:

$$
\begin{aligned}
V &= D_0\left(\frac{1+g}{k-g}\right) \\
&= D_0\left[\frac{1+r(1-p)}{k-r(1-p)}\right]. \\
&= D_1\left[\frac{1}{k-r(1-p)}\right].
\end{aligned}
\tag{1}
$$

Under these assumptions, a stock's value (and hence its price) should be greater, the greater its average return on equity for new investments, other things being equal.

Example

Continuing with the Copper Company, recall that $E_0 = \$2.70$ and $p = 66\frac{2}{3}\%$. This means that $33\frac{1}{3}\%$ of earnings per share over the past year were retained and reinvested, an amount equal to \$.90 (= .3333 × \$2.70). The earnings per share in the forthcoming year E_1 are expected to be \$2.835 [= \$2.70 × (1 + .05)] because the growth rate g for Copper is 5%.

The source of the increase in earnings per share of \$.135 (= \$2.835 − \$2.70) is the \$.90 per share that was reinvested at $t = 0$. The average return on equity for new investments r is 15%, because \$.135/\$.90 = 15%. That is, the reinvested earnings of \$.90 per share can be viewed as having generated an annual increase in earnings per share of \$.135. This increase will occur not only at $t = 1$, but also at $t = 2$, $t = 3$, and so on. Equivalently, a \$.90 investment at $t = 0$ will generate a perpetual annual cash inflow of \$.135 beginning at $t = 1$.

Expected dividends at $t = 1$ can be calculated by multiplying the expected payout ratio p of $66\frac{2}{3}\%$ times the expected earnings per share E_1 of \$2.835, or .6667 × \$2.835 = \$1.89. It can also be calculated by multiplying 1 plus the growth rate g of 5% times the past amount of dividends per share D_0 of \$1.80, or 1.05 × \$1.80 = \$1.89.

It can be seen that the growth rate in dividends per share of 5% is equal to the product of the retention rate ($33\frac{1}{3}\%$) and the average return on equity for new investments (15%), an amount equal to 5% (= .3333 × .15).

Two years from now ($t = 2$), earnings per share are anticipated to be \$2.977 [= \$2.835 × (1 + .05)], a further increase of \$.142 (= \$2.977 − \$2.835) that is due to the retention and reinvestment of \$.945 (= .3333 × \$2.835) per share at $t = 1$. This expected increase in earnings per share of \$.142 is the result of earning (15%) on the reinvestment (\$.945), because .15 × \$.945 = \$.142.

The expected earnings per share at $t = 2$ can be viewed as having three components. The first is the earnings attributable to the assets held at $t = 0$, an amount equal to \$2.70. The second is the earnings attributable to the reinvestment of \$.90 at $t = 0$, earning \$.135. The third is the earnings attributable to the reinvestment of \$.945 at $t = 1$, earning \$.142. These three components, when summed, can be seen to equal $E_2 = \$2.977$ (= \$2.70 + \$.135 + \$.142).

Dividends at $t = 2$ are expected to be 5% larger than at $t = 1$, or \$1.985 (= 1.05 × \$1.89) per share. This amount corresponds to the amount calculated by multiplying the payout ratio times the expected earnings per share at $t = 2$, or \$1.985 (= .6667 × \$2.977). Figure 18.2 summarizes the example.

−1	0	1	2	—>∞
E_0 = \$2.70	\$2.700	\$2.700		. . .
	\$.90 x .15 = .135	.135		. . .
	E_1 = \$2.835	\$.945 x .15 = .142		. . .
		E_2 = \$2.977		. . .
I_0 = \$ .90	I_1 = \$ .945	I_2 = \$ .992		. . .
D_0 = 1.80	D_1 = 1.890	D_2 = 1.985		. . .
E_0 = \$2.70	E_1 = \$2.835	E_2 = \$2.977		. . .

Figure 18.2
Growth in Earnings for Copper Company

18.8 A THREE-STAGE DDM

As this chapter's Institutional Issues discusses, the three-stage DDM is the most widely applied form of the general multiple-growth DDM. Consider analyzing the *ABC* Company.

18.8.1 Making Forecasts

Over the past year, *ABC* has had earnings per share of \$1.67 and dividends per share of \$.40. After carefully studying ABC, the security analyst has made the following forecasts of earnings per share and dividends per share for the next five years:

$$E_1 = \$2.67 \quad E_2 = \$4.00 \quad E_3 = \$6.00 \quad E_4 = \$8.00 \quad E_5 = \$10.00$$
$$D_1 = \$\ .60 \quad D_2 = \$1.60 \quad D_3 = \$2.40 \quad D_4 = \$3.20 \quad D_5 = \$\ 5.00.$$

These forecasts imply the following payout ratios and earnings-per-share growth rates:

$$p_1 = 22\% \quad p_2 = 40\% \quad p_3 = 40\% \quad p_4 = 40\% \quad p_5 = 50\%$$
$$g_{e1} = 60\% \quad g_{e2} = 50\% \quad g_{e3} = 50\% \quad g_{e4} = 33\% \quad g_{e5} = 25\%.$$

Furthermore, the analyst believes that *ABC* will enter a transition stage at the end of the fifth year (that is, the sixth year will be the first year of the transition stage), and that the transition stage will last three years. Earnings per share and payout ratio for year 6 are forecast to be E_6 = \$11.90 and p_6 = 55%. {Thus g_{e6} = 19% [= (\$11.90 − \$10.00)/\$10.00] and D_6 = \$6.55 (= .55 × \$11.90)}.

The last stage, known as the maturity stage, is forecast to have an earnings-per-share growth rate of 4% and a payout ratio of 70%. Now it was shown in Equation (18.51b) that with the constant-growth model, $g = r(1 - p)$, where r is the average return on equity for new investment and p is the payout ratio. Given

Applying Dividend Discount Models

Over the last 30 years, dividend discount models (DDMs) have achieved broad acceptance among professional common stock investors. Although few investment managers rely solely on DDMs to select stocks, many have integrated DDMs into their security valuation procedures.

The reasons for the popularity of DDMs are twofold. First, DDMs are based on a simple, widely understood concept: The fair value of any security should equal the discounted value of the cash flows expected to be produced by that security. Second, the basic inputs for DDMs are standard outputs for many large investment management firms—that is, these firms employ security analysts who are responsible for projecting corporate earnings.

Valuing common stocks with a DDM technically requires an estimate of future dividends over an infinite time horizon. Given that accurately forecasting dividends three years from today, let alone 20 years in the future, is a difficult proposition, how do investment firms actually go about implementing DDMs?

One approach is to use constant or two-stage dividend growth models, as described in the text. However, although such models are relatively easy to apply, institutional investors typically view the assumed dividend growth assumptions as overly simplistic. Instead, these investors generally prefer three-stage models, believing that they provide the best combination of realism and ease of application.

Whereas many variations of the three-stage DDM exist, in general, the model is based on the assumption that companies evolve through three stages during their lifetimes. (Figure 18.3 portrays these stages.)

1. **Growth stage:** Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.
2. **Transition stage:** In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

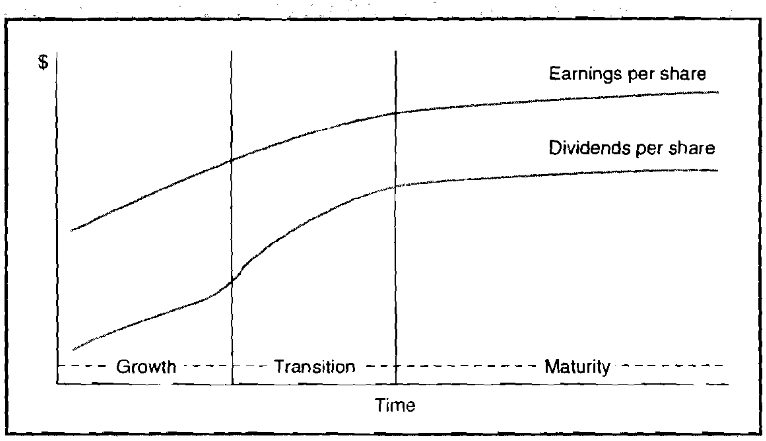


Figure 18.3
The Three Stages of the Multiple-Growth Model
Source: Adapted from Carmine J. Grigoli, "Demystifying Dividend Discount Models," *Merrill Lynch Quantitative Research*, April 1982.

INSTITUTIONAL ISSUES (continued)

3. **Maturity (steady-state) stage:** Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life.

The forecasting process of the three-stage DDM involves specifying earnings and dividend growth rates in each of the three stages. Although one cannot expect a security analyst to be omniscient in his or her growth forecast for a particular company, one can hope that the forecast pattern of growth—in terms of magnitude and duration—resembles that actually realized by the company, particularly in the short run.

Investment firms attempt to structure their DDMs to make maximum use of their analysts' forecasting capabilities. Thus the models emphasize specific forecasts in the near term, when it is realistic to expect security analysts to project earnings and dividends more accurately. Conversely, the models emphasize more general forecasts over the longer term, when distinctions between companies' growth rates become less discernible. Typically, analysts are required to supply the following for their assigned companies:

1. expected annual earnings and dividends for the next several years;
2. after these specific annual forecasts end, earnings growth and the payout ratio forecasts until the end of the growth stage;
3. the number of years until the transition stage is reached;
4. the duration (in years) of the transition stage—that is, once abnormally high growth ends, the number of years until the maturity stage is reached.

Most three-stage DDMs assume that during the transition stage, earnings growth declines and payout ratios rise linearly to the maturity-stage steady-state levels. (For example, if the transition stage is ten years long, earnings growth at the maturity stage is 5% per year, and earnings growth at the end of the growth stage is 25%, then earnings growth will decline 2% in each year of the transition stage.) Finally, most three-stage DDMs make standard assumptions that all companies in the maturity stage have the same growth rates, payout ratios, and return on equity.

With analysts' inputs, plus an appropriate required rate of return for each security, all the necessary information for the three-stage DDM is available. The last step involves merely calculating the discounted value of the estimated dividends to determine the stock's "fair" value.

The seeming simplicity of the three-stage DDM should not lead one to believe that it is without its implementation problems. Investment firms must strive to achieve consistency across their analysts' forecasts. The long-term nature of the estimates involved, the substantial training required to make even short-term earnings forecasts accurately, and the coordination of a number of analysts covering many companies severely complicate the problem. Considerable discipline is required if the DDM valuations generated by a firm's analysts are to be sufficiently comparable and reliable to guide investment decisions. Despite these complexities, if successfully implemented, DDMs can combine the creative insights of security analysts with the rigor and discipline of quantitative investment techniques.

that the maturity stage has constant growth, this equation can be reformulated and used to determine r:

$$r = g/(1 - p).$$

Thus r for ABC has an implied value of 13.33% [= 4%/(100% − 70%)], which is assumed to be consistent with the long-run growth forecasts for similar companies.

At this point there are only two missing pieces of information that are needed to determine the value of ABC—the earnings-per-share growth rates and the payout ratios for the transition stage. Taking earnings per share first, ... forecast that $g_{e6} = 19\%$ and $g_{e9} = 4\%$. One method of determining ... "decay" to 4% is to note that there are three years between the sixth ... years, and 15% between 19% and 4%. A "linear decay" rate would be ... by noting that 15%/3 years = 5% per year. This rate of 5% would be ... from 19% to get g_{e7}, resulting in 14% (= 19% − 5%). Then it would be ... ed from 14% to get g_{e8}, resulting in 9% (= 14% − 5%). Finally, as a check ... be noted that 4% (= 9% − 5%) is the value that was forecast for g_{e9}.

A similar procedure can be used to determine how the payout ratio ... in year 6 will grow to 70% in year 9. The "linear growth" rate will be (70% − 55%)/3 years = 15%/3 years = 5% per year, indicating that p_7 = 60% (= ... + 5%) and p_8 = 65% (= 60% + 5%). Again a check indicates that 70% (= 65% + 5%) is the value that was forecast for p_9.

With these forecasts of earnings-per-share growth rates and payout ratios in hand, forecasts of dividends per share can now be made:

$$
\begin{aligned}
D_7 &= p_7 E_7 \\
&= p_7 E_6 (1 + g_{e7}) \\
&= .60 \times \$11.90 \times (1 + .14) \\
&= .60 \times \$13.57 \\
&= \$8.14 \\
D_8 &= p_8 E_8 \\
&= p_8 E_6 (1 + g_{e7})(1 + g_{e8}) \\
&= .65 \times \$11.90 \times (1 + .14) \times (1 + .09) \\
&= .65 \times \$14.79 \\
&= \$9.61 \\
D_9 &= p_9 E_9 \\
&= p_9 E_6 (1 + g_{e7})(1 + g_{e8})(1 + g_{e9}) \\
&= .70 \times \$11.90 \times (1 + .14) \times (1 + .09) \times (1 + .04) \\
&= .70 \times \$15.38 \\
&= \$10.76.
\end{aligned}
$$

18.8.2 Estimating the Intrinsic Value

Given a required rate of return on *ABC* of 12.4%, all the necessary inputs for the multiple-growth model have been determined. Hence it is now possible to estimate *ABC*'s intrinsic (or fair) value. To begin, it can be seen that $T = 8$, indicating that V_{T-} involves determining the present value of D_1 through D_8,

$$
\begin{aligned}
V_{T-} &= \left[\frac{\$.60}{(1 + .124)^1}\right] + \left[\frac{\$1.60}{(1 + .124)^2}\right] + \left[\frac{\$2.40}{(1 + .124)^3}\right] \\
&\quad + \left[\frac{\$3.20}{(1 + .124)^4}\right] + \left[\frac{\$5.00}{(1 + .124)^5}\right] + \left[\frac{\$6.55}{(1 + .124)^6}\right] \\
&\quad + \left[\frac{\$8.14}{(1 + .124)^7}\right] + \left[\frac{\$9.61}{(1 + .124)^8}\right] \\
&= \$18.89.
\end{aligned}
$$

Then V_{T+} can be determined using D_9:

$$V_{T+} = \frac{\$10.76}{(.124 - .04)(1 + .124)^8}$$
$$= \$50.28.$$

Combining V_{T-} and V_{T+} results in the intrinsic value of *ABC:*

$$V = V_{T-} + V_{T+}$$
$$= \$18.89 + \$50.28$$
$$= \$69.17.$$

Given a current market price for *ABC* of \$50, it can be seen that its stock is underpriced by \$19.17 (= \$69.17 − \$50) per share. Equivalently, it can be noted that the actual price-earnings ratio for *ABC* is 29.9 (= \$50/\$1.67) but that a "normal" price-earnings ratio would be higher, equal to 41.4 (= \$69.17/\$1.67), again indicating that *ABC* is underpriced.

18.8.3 Implied Returns

As shown with the previous example, once the analyst has made certain forecasts, it is relatively straightforward to determine a company's expected dividends for each year up through the first year of the maturity stage. Then the present value of these predicted dividends can be calculated for a given required rate of return. However, many investment firms use a computerized trial-and-error procedure to determine the discount rate that equates the present value of the stock's expected dividends with its current price. Sometimes this long-run internal rate of return is referred to as the security's **implied return.** In the case of *ABC* its implied return is 14.8%.

18.8.4 The Security Market Line

After implied returns have been estimated for a number of stocks, the associated beta for each stock can be estimated. Then for all the stocks analyzed, this information can be plotted on a graph that has implied returns on the vertical axis and estimated betas on the horizontal axis.

At this point there are alternative methods for estimating the security market line (SML).[11] One method involves determining a line of best fit for this graph by using a statistical procedure known as simple regression (as discussed in Chapter 17). That is, the values of an intercept term and a slope term are determined from the data, thereby indicating the location of the straight line that best describes the relationship between implied returns and betas.[12]

Figure 18.4 provides an example of the estimated SML. In this case the SML has been determined to have an intercept of 8% and a slope of 4%, indicating that, in general, securities with higher betas are expected to have higher implied returns in the forthcoming period. Depending on the sizes of the implied returns, such lines can have steeper or flatter slopes, or even negative slopes.

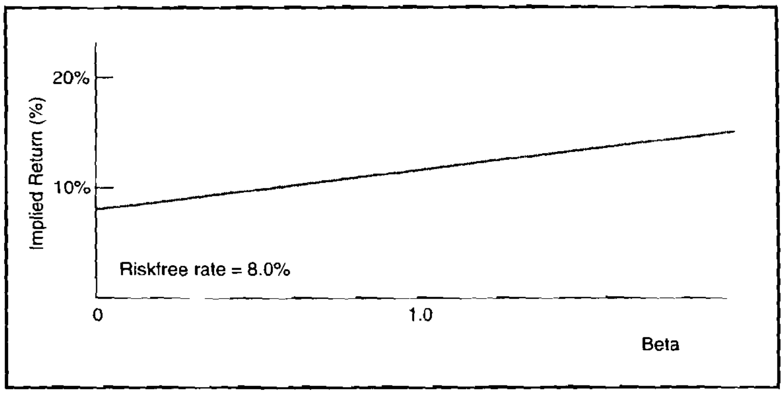


Figure 18.4
A Security Market Line Estimated from Implied Returns

The second method of estimating the SML involves calculating the implied return for a portfolio of common stocks. This is done by taking a value-weighted average of the implied returns of the stocks in the portfolio, with the resulting return being an estimate of the implied return on the market portfolio. Given this return and a beta of 1, the "market" portfolio can be plotted on a graph having implied returns on the vertical axis and betas on the horizontal axis. Next the riskfree rate, having a beta of 0, can be plotted on the same graph. Finally, the SML is determined by simply connecting these two points with a straight line.

Either of these SMLs can be used to determine the required return on a stock. However, they will most likely result in different numbers, as the two lines will most likely have different intercepts and slopes. For example, note that in the first method the SML may not go through the riskfree rate, whereas the second method forces the SML to go through this rate.

18.8.5 Required Returns and Alphas

Once a security's beta has been estimated, its required return can be determined from the estimated SML. For example, the equation for the SML shown in Figure 18.4 is:

$$k_i = 8 + 4\beta_i.$$

Thus if *ABC* has an estimated beta of 1.1, then it would have a required return equal to 12.4% $[= 8 + (4 \times 1.1)]$.

Once the required return on a stock has been determined, the difference between the stock's implied return (from the DDM) and this required return can be calculated. This difference is then viewed as an estimate of the stock's *alpha* and represents "... the degree to which a stock is mispriced. Positive alphas indicate undervalued securities and negative alphas indicate overvalued securities."[13] In the case of *ABC*, its implied and required returns were 14.8% and 12.4%, respectively. Thus its estimated alpha would be 2.4% (= 14.8% − 12.4%). Because this is a positive number, *ABC* can be viewed as being underpriced.

18.8.6 The Implied Return on the Stock Market

Another product of this analysis is that the implied return for a portfolio of stocks can be compared with the expected return on bonds. (The latter is typically represented by the current yield-to-maturity on long-term Treasury bonds.) Specifically, the difference between stock and bond returns can be used as an input for recommendations concerning asset allocation between stocks and bonds. That is, it can be used to form recommendations regarding what percent of an investor's money should go into stocks and what percent should go into bonds. For example, the greater the implied return on stocks relative to bonds, the larger the percentage of the investor's money that should be placed in common stocks.

18.9 DIVIDEND DISCOUNT MODELS AND EXPECTED RETURNS

The procedures described here are similar to those employed by a number of brokerage firms and portfolio managers.[14] A security's implied return, obtained from a DDM, is often treated as an expected return, which in turn can be divided into two components—the security's required return and alpha.

However, the expected return on a stock over a given holding period may differ from its DDM-based implied rate k^*. A simple set of examples will indicate why this difference can exist.

Assume that a security analyst predicts that a stock will pay a dividend of \$1.10 per year forever. On the other hand, the consensus opinion of "the market" (most other investors) is that the dividend will equal \$1.00 per year forever. This suggests that the analyst's prediction is a deviant or nonconsensus one.

Assume that both the analyst and other investors agree that the required rate of return for a stock of this type is 10%. Using the formula for the zero-growth model, the value of the stock is $D_1/.10 = 10D_1$, meaning that the stock should sell for ten times its expected dividend. Because other investors expect to receive \$1.00 per year, the stock has a current price P of \$10 per share. The analyst feels that the stock has a value of $\$1.10/.10 = \$11$ and thus feels that it is underpriced by $\$11 - \$10 = \$1$ per share.

18.9.1 Rate of Convergence of Investors' Predictions

[illegible] this situation the implied return according to the analyst is $\$1.10/\$10 = 11\%$. [illegible] the analyst buys a share now with a plan to sell it a year later, what rate of re[illegible] might the analyst expect to earn? The answer depends on what assumption [illegible]de regarding the *rate of convergence of investors' predictions*—that is, the an[illegible]depends on the expected market reaction to the mispricing that the analyst [illegible] currently exists.

[illegible] cases shown in Table 18.1 are based on an assumption that the analyst is [illegible] that his or her forecast of future dividends is correct. That is, in all of [illegible] the analyst expects that at the end of the year, the stock will pay the [illegible] dividend of \$1.10.

TABLE 18.1

ALPHA AND THE CONVERGENCE OF PREDICTIONS

	Expected Amount of Convergence		
	0% (A)	100% (B)	50% (C)
Dividend predictions D_2			
Consensus of other investors	1.00	1.10	1.05
Analyst	1.10	1.10	1.10
Expected stock price P_1	10.00	11.00	10.50
Expected return:			
Dividence yield D_1/P	11%	11%	11%
Capital gain $(P_1 - P)/P$	0	10	5
Total expected return	11%	21%	16%
Less required return	10	10	10
Alpha	1%	11%	6%

Note: P_1 is equal to the consensus dividend prediction at t = 1 divided by the required return of 10%. The example assumes that the current stock price P is $10, and dividends are forecast by the consensus at t = 0 to remain constant at $1.00 per share, whereas the analyst forecasts the dividends at t = 0 to remain constant at $1.10 per share.

No Convergence

In column (A), it is assumed that other investors will regard the higher dividend as a fluke and steadfastly refuse to alter their projections of subsequent dividends from their initial estimate of $1.00. As a result, the security's price at $t = 1$ can be expected to remain at $10 (= $1.00/.10). In this case the analyst's total return is expected to be 11% (= $1.10/$10), which will be attributed entirely to dividends as no capital gains are expected.

The 11% expected return can also be viewed as consisting of the required return of 10% plus an alpha of 1% that is equal to the portion of the dividend unanticipated by other investors, $.10/$10. Accordingly, if it is assumed that there will be no convergence of predictions, the expected return would be set at the implied rate of 11% and the alpha would be set at 1%.

Complete Convergence

Column (B) shows a very different situation. Here it is assumed that the other investors will recognize their error and completely revise their predictions. At the end of the year, it is expected that they too will predict future dividends of $1.10 per year thereafter; thus the stock is expected to be selling for $11 (= $1.10/.10) at $t = 1$. Under these conditions, the analyst can expect to achieve a total return of 21% by selling the stock at the end of the year for $11, obtaining 11% (= $1.10/$10) in dividend yield and 10% (= $1/$10) in capital gains.

The 10% expected capital gains result directly from the expected repricing of the security because of the complete convergence of predictions. In this case the fruits of the analyst's superior prediction are expected to be obtained all in one year. Instead of 1% "extra" per year forever, as in column (A), the analyst expects to obtain 1% (= \$.10/\$10) in extra dividend yield plus 10% (= \$1/\$10) in capital gains this year. By continuing to hold the stock in subsequent years, the analyst would expect to earn only the required return of 10% over those years. Accordingly, the expected return is 21% and the alpha is 11% when it is assumed that there is complete convergence of predictions.

Partial Convergence

Column (C) shows an intermediate case. Here the predictions of the other investors are expected to converge only halfway toward those of the analyst (that is, from \$1.00 to \$1.05 instead of to \$1.10). Total return in the first year is expected to be 16%, consisting of 11% (= \$1.10/\$10) in dividend yield plus 5% (= \$.50/\$10) in capital gains.

Since the stock is expected to be selling for \$10.50 (= \$1.05/.10) at $t = 1$, the analyst will still feel that it is underpriced at $t = 1$ because it will have an intrinsic value of \$11 (= \$1.10/.10) at that time. To obtain the remainder of the "extra return" owing to this underpricing, the stock would have to be held past $t = 1$. Accordingly, the expected return would be set at 16% and the alpha would be set at 6% when it is assumed that there is halfway convergence of predictions.

In general, a security's expected return and alpha will be larger, the faster the assumed rate of convergence of predictions.[15] Many investors use the implied rate (that is, the internal rate of return k^*) as a surrogate for a relatively short-term (for example, one year) expected return, as in column (A). In doing so, they are assuming that the dividend forecast is completely accurate, but that there is no convergence. Alternatively, investors could assume that there is some degree of convergence, thereby raising their estimate of the security's expected return. Indeed, investors could further alter their estimate of the security's expected return by assuming that the security analyst's deviant prediction is less than perfectly accurate, as will be seen next.[16]

18.9.2 Predicted versus Actual Returns

An alternative approach does not simply use outputs from a model "as is," but *adjusts* them, based on relationships between previous predictions and actual outcomes. Panels (a) and (b) of Figure 18.5 provide examples.

Each point in Figure 18.5(a) plots a *predicted return* on the stock market as a whole (on the horizontal axis) and the subsequent *actual return* for that period (on the vertical axis). The line of best fit (determined by simple regression) through the points indicates the general relationship between prediction and outcome. If the current prediction is 14%, history suggests that an estimate of 10% would be superior.

Each point in Figure 18.5(b) plots a predicted alpha value for a security (on the horizontal axis) and the subsequent "abnormal return" for that period (on the vertical axis). Such a diagram can be made for a given security, or for all the securities that a particular analyst makes predictions about, or for all the securities that the investment firm makes predictions about. Again a line of best fit can be drawn through the points. In this case, if the current prediction of a security's

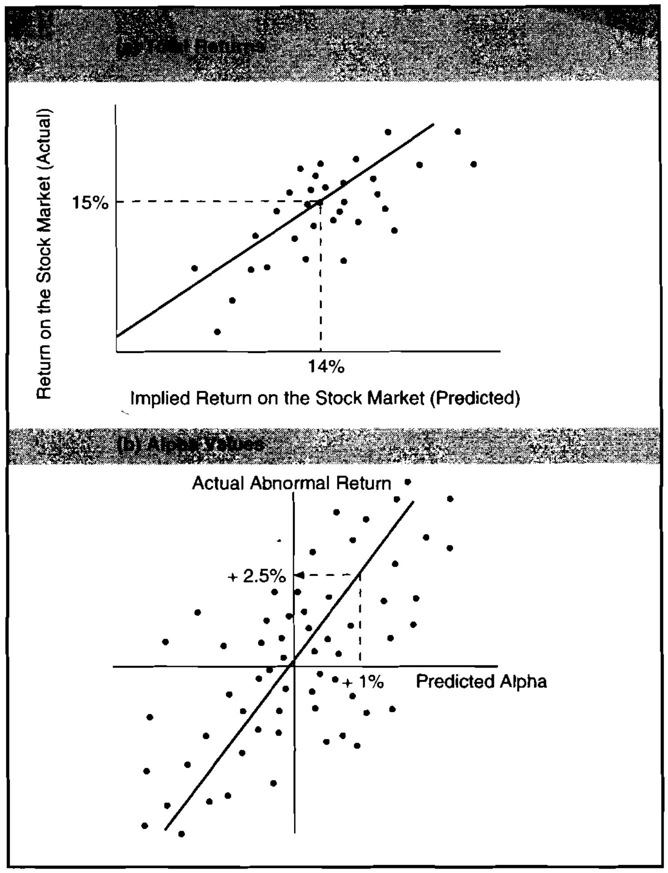


Figure 18.5
Adjusting Predictions

alpha is +1%, this relationship suggests that an "adjusted" estimate of +2.5% would be superior.

An important by-product of this type of analysis is the measure of correlation between predicted and actual outcomes, indicating the nearness of the points to the line. This **information coefficient** (IC) can serve as a measure of predictive accuracy. If it is too small to be significantly different from zero in a statistical sense, the value of the predictions is subject to considerable question.[17]

18.10 SUMMARY

1. The capitalization of income method of valuation states that the intrinsic value of any asset is equal to the sum of the discounted cash flows investors expect to receive from that asset.

2. Dividend discount models (DDMs) are a specific application of the capitalization of income method of valuation to common stocks.
3. To use a DDM, the investor must implicitly or explicitly supply a forecast of all future dividends expected to be generated by a security.
4. Investors typically make certain simplifying assumptions about the growth of common stock dividends. For example, a common stock's dividends may be assumed to exhibit zero growth or growth at a constant rate. More complex assumptions may allow for multiple growth rates over time.
5. Instead of applying DDMs, many security analysts use a simpler method of security valuation that involves estimating a stock's "normal" price-earnings ratio and comparing it with the stock's actual price-earnings ratio.
6. The growth rate in a firm's earnings and dividends depends on its earnings retention rate and its average return on equity for new investments.
7. Determining whether a security is mispriced using a DDM can be done in one of two ways. First, the discounted value of expected dividends can be compared with the stock's current price. Second, the discount rate that equates the stock's current price to the present value of forecast dividends can be compared with the required return for stocks of similar risk.
8. The rate of return that an analyst with accurate non-consensus dividend forecasts can expect to earn depends on the rate of convergence of other investors' predictions to the predictions of the analyst.

Questions and Problems

1. Consider five annual cash flows (the first occurring one year from today):

Year	Cash Flow
1	\$5
2	\$6
3	\$7
4	\$8
5	\$9

Given a discount rate of 10%, what is the present value of this stream of cash flows?

Alta Cohen is considering buying a machine to produce baseballs. The machine costs \$10,000. With the machine, Alta expects to produce and sell 1,000 baseballs per year for \$3 per baseball, net of all costs. The machine's life is five years (with no salvage value). Based on these assumptions and an 8% discount rate, what is the net present value of Alta's investment?

Hub Collins has invested in a project that promised to pay \$100, \$200, and \$300, respectively, at the end of the next three years. If Hub paid \$513.04 for this investment, what is the project's internal rate of return?

ton Products currently pays a dividend of \$4 per share on its common stock.

Equity Risk Premium QUARTERLY

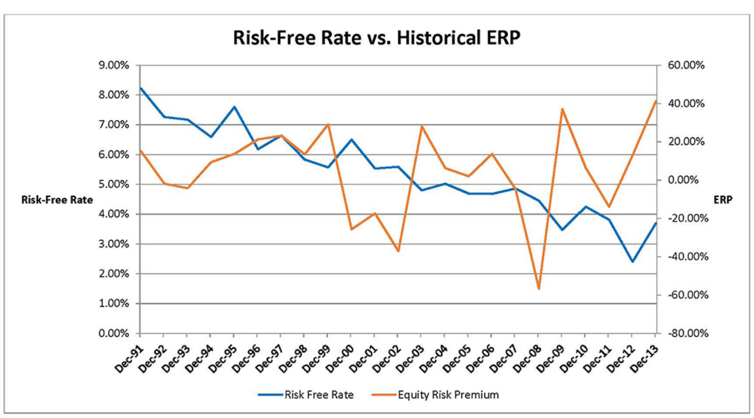
January 2015

US Equity Risk Premium

The equity risk premium ("ERP") is the extra return over the expected yield on risk-free securities that investors expect to receive from an investment in a diversified portfolio of common stocks.[1] It can also be thought to measure what investors demand over and above the risk-free rate for investing in equities as a class or the market price for taking on average equity risk.[2]

In recent years, US risk-free rates have reached levels near historic lows due to the perceived low risk of US treasuries relative to the sovereign debt of other developed nations. Additionally, the Federal Reserve and other Central Banks around the world have undertaken quantitative easing and other efforts to lower interest rates in response to economic conditions. This past quarter, the Federal Reserve announced it would conclude its asset purchase program; however, it will continue to maintain its existing bond holdings and reinvest principal payments. This effort, along with the current lending rate policy, will help maintain accommodative financial conditions. As a result, the capital asset pricing model ("CAPM"), which utilizes the ERP to calculate a cost of equity, has implied a below-average cost of equity when the market may have exhibited higher risk. Yields on US Treasury bonds, which were being manipulated by government intervention, were the primary driver for the implied below-average cost of equity. In the past year, US Treasury yields have been declining after returning to normal levels for a brief period of time late in 2013. Several reasons have been cited for the decline in US Treasury rates, most notably the shift from EU sovereign debt to US Treasuries, geopolitical unrest, pension funds protecting their status and, more recently, a sharp decline in worldwide energy prices. Another factor is the Federal Reserve signaling to the markets that rates may not be raised as previously expected until 2016. Yields on the 20-year US Treasury bond have declined to 2.47% as of December 31, 2014, from 3.08% as of June 30, 2014, and 3.72% as of December 31, 2013. It is too soon to determine whether this pullback trend will last throughout 2015.

Research has shown that the ERP is cyclical during business cycles and that the ERP can fluctuate within its historic range based on current and forecasted economic conditions. The ERP tends



to move in the opposite direction of the economy, so when the business cycle is at its peak, the ERP will be at the lower end of its historical range; conversely, during economic troughs, the ERP will be at the higher end of the range.[1] The historical risk-free rate and ERP are presented in the chart on the preceding page.

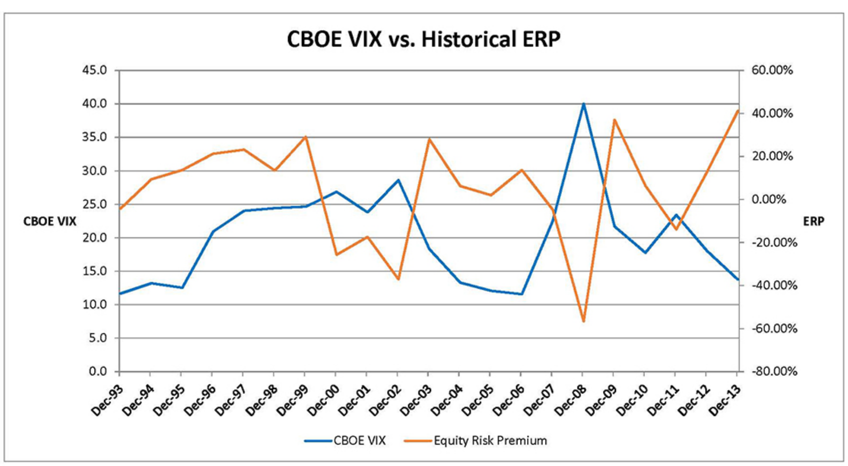
There is no single universally accepted methodology for estimating the ERP; thus, there is wide diversity in practice among academics and financial advisors with regard to recommended ERP estimates.

American Appraisal researched and analyzed various economic and market factors in order to determine where the current ERP should fall within a range of historical ERP. To determine which indicators were most relevant to the ERP, correlations were calculated for these indicators relative to the historical ERP. Long-term correlations greater than +/- 0.5 were considered meaningful.

Based on our research and analysis, American Appraisal utilizes a 6.0% US ERP combined with the actual risk-free rate as of January 2015, which is consistent with our conclusion for the prior quarter. Additional details of the factors we reviewed follow.

Economic/Market Indicators

The factors determined to display moderate or strong correlations with historical ERPs are the CBOE Volatility Index ("VIX"), Damodaran's implied premium, and Moody's Aaa and Baa 20-year corporate credit spreads. VIX is the ticker symbol for the Chicago Board Options Exchange ("CBOE") Volatility Index, which numerically expresses the market's expectations of 30-day volatility; it is constructed by using the implied volatilities of a wide range of S&P 500 Index options. The results are meant to be forward-looking and are calculated by using both call and put options.



1993-2013 Correlation (20 year):	-0.59
2003-2013 Correlation (10 year):	-0.74

The VIX is a widely used measure of market risk and often is referred to as the investor fear gauge. There are three variations of the volatility indexes: (1) the VIX, which tracks the S&P 500; (2) the VXN, which tracks the Nasdaq 100; and (3) the VXD, which tracks the Dow Jones Industrial Average. Damodaran's implied premium, developed by Aswath Damodaran, Professor of Finance at the Stern School of Business at New York University, is a forward-looking approach to calculating an expected ERP. It is based on using current market data to calculate an implied or residualized ERP.[3]

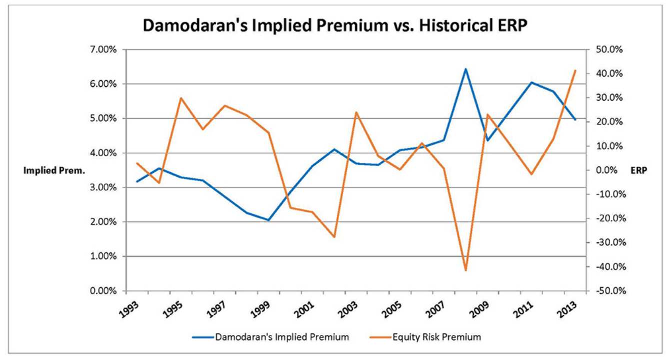
Moody's Aaa corporate credit spreads are calculated based on the difference in Aaa corporate yields vs. US treasuries with similar maturities.

Economic Indicators

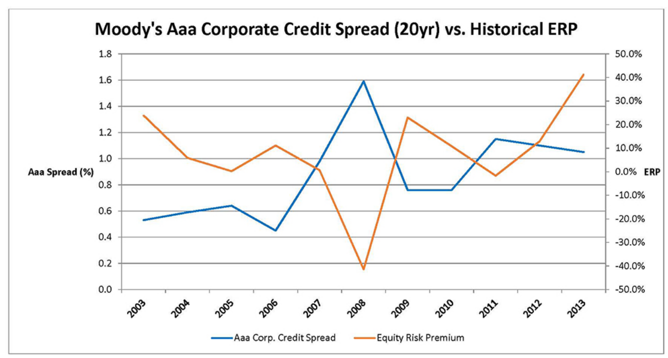
As described previously, the VIX, Damodaran's implied premium, and Moody's Aaa and Baa 20-year corporate credit spreads display meaningful correlations with historical ERPs. Each of the factors is briefly discussed below:

Damodaran's Implied Premium

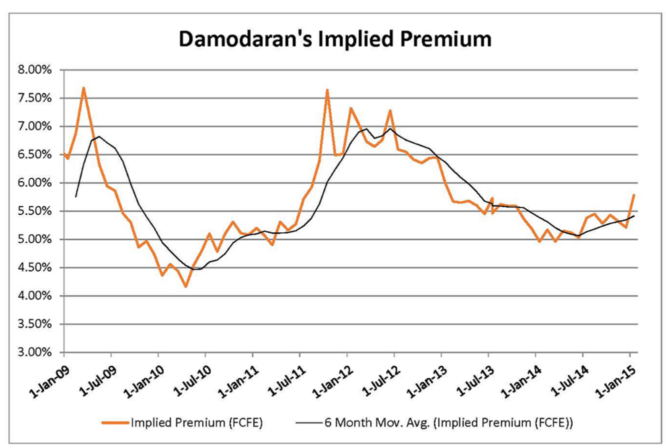
The six-month moving average trendline suggests that the implied premium has steadily trended down from 7.0% toward 6.0%, and dropped sharply - to slightly below 5% - at the end of 2013. It is now back up near 6% at the end of 2014.



1993-2013 Correlation (20 year):	-0.30
2003-2013 Correlation (10 year):	-0.49

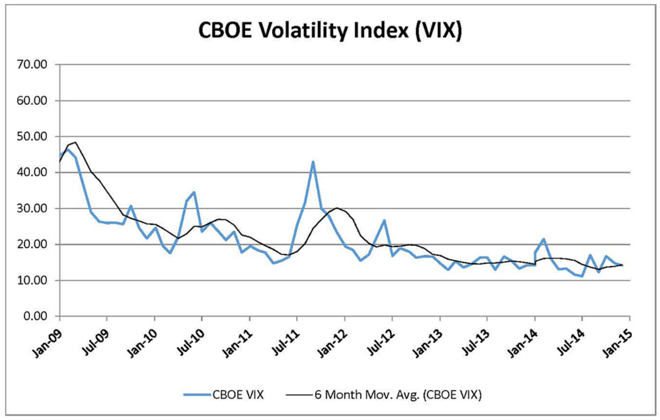


2003-2013 Correlation (10 year):	-0.55



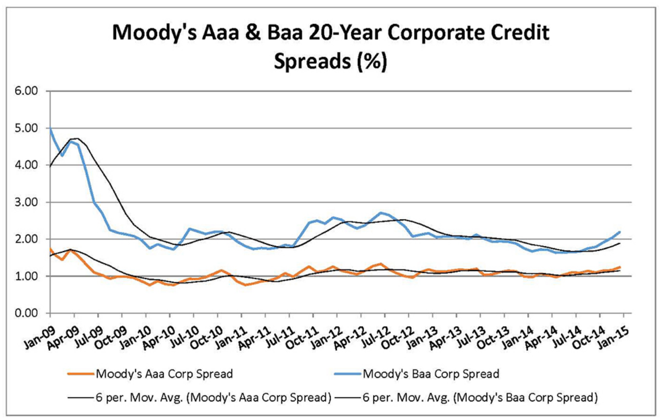
CBOE Volatility Index (VIX)

The VIX appears to be bouncing back from its lows, which approached low double digits, and increased to approximately 17 (long-term average near 20) at the end of September 2014. The VIX has fluctuated considerably over the past few years, spiking to over 40 in 2011. Since the first quarter of 2012, the six-month trendline has dipped down below 20 and is trending toward 15. The index is hovering close to the near-record lows throughout 2014 but toward the end of the year it trended toward 20, reflecting turmoil in the energy markets.



Moody's Aaa and Baa Corporate Credit Spreads (20-year)

In 2012, Aaa and Baa spreads fell, rose, fell, and rose again, while their six-month moving averages remained relatively flat. Since January 2013, corporate credit spreads have remained relatively flat; however, the corporate spreads began to widen slightly over the fourth quarter of 2014.

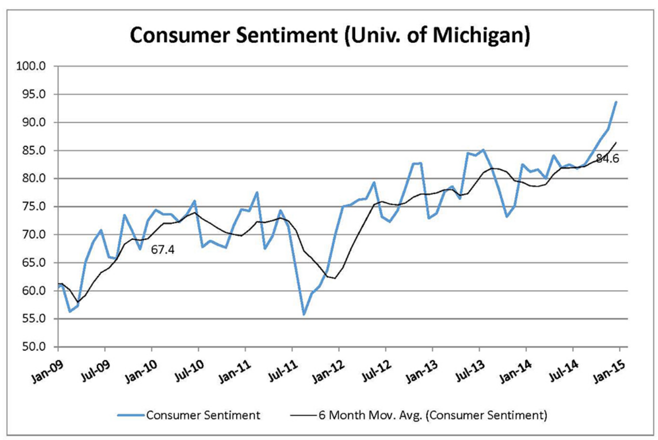


Additional Economic Indicators

In addition to the economic and market factors that display meaningful correlations with historical ERPs, the following economic indicators are monitored on a frequent basis to determine the current status of the US economy and help establish where the current ERP falls within the historical range.

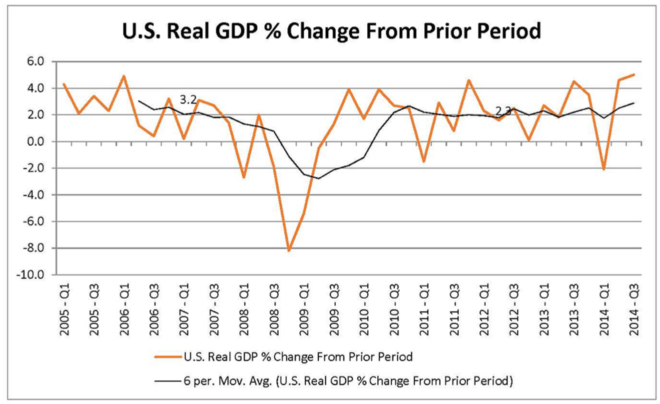
Consumer Sentiment

Consumer sentiment trends, as tracked by the University of Michigan, indicate improving consumer sentiment, which is typically preceded by positive economic trends. The survey has continued to trend toward new highs, with the latest survey posting a result of 93.6.



US Real GDP

The six-month moving average trendline for US real GDP indicates a relatively flat economy with slower growth trending above 2.0%. During the first quarter of 2014 the economy contracted at an annual rate of 2.9%. Economists cite much of the contraction to the bad weather that much of the country endured, which affected production, construction, and shipments. Many economists correctly projected improvement in the second quarter of 2014, with an annualized real growth rate of 4.6%. The economic growth observed in Q2 continued in Q3 with an annualized real growth rate of 5.0%. This is considered a coincident indicator by economists and is neither leading nor lagging.



Conclusion

As the ERP is cyclical and can fluctuate within its historical range based on current and economic conditions, please consult with your American Appraisal valuation advisor when developing a weighted average cost of capital or, more specifically, the cost of equity for your business.

Visit www.american-appraisal.com for more information.

Sources

[1]Shannon Pratt and Roger Grabowski, *Cost of Capital: Applications and Examples*, fourth edition (New York: John Wiley & Sons, 2010), pages 115, 137.

[2] Aswath Damodaran, "Risk Premiums: Looking backwards and forwards…" (presentation, October 2011).

[3] Aswath Damodaran, *Equity Risk Premiums (ERP): Determinants, Estimation and Implications - The 2013 Edition* (paper, updated March 2013).

Earnings Growth: The Two Percent Dilution

William J. Bernstein and Robert D. Arnott

Two important concepts played a key role in the bull market of the 1990s. Both represent fundamental flaws in logic. Both are demonstrably untrue. First, many investors believed that earnings could grow faster than the macroeconomy. In fact, earnings must grow slower than GDP because the growth of existing enterprises contributes only part of GDP growth; the role of entrepreneurial capitalism, the creation of new enterprises, is a key driver of GDP growth, and it does not contribute to the growth in earnings and dividends of existing enterprises. During the 20th century, growth in stock prices and dividends was 2 percent less than underlying macroeconomic growth. Second, many investors believed that stock buybacks would permit earnings to grow faster than GDP. The important metric is not the volume of buybacks, however, but net buybacks—stock buybacks less new share issuance, whether in existing enterprises or through IPOs. We demonstrate, using two methodologies, that during the 20th century, new share issuance in many nations almost always exceeded stock buybacks by an average of 2 percent or more a year.

The bull market of the 1990s was largely built on a foundation of two immense misconceptions. Whether their originators were knaves or fools is immaterial; the errors themselves were, and still are, important. Investors were told the following:

1. With a technology revolution and a "new paradigm" of low payout ratios and internal reinvestment, earnings will grow faster than ever before. Real growth of 5 percent will be easy to achieve.

Like the myth of Santa Claus, this story is highly agreeable but is supported by neither observable current evidence nor history.

2. When earnings are not distributed as dividends and not reinvested into stellar growth opportunities, they are distributed back to shareholders in the form of stock buybacks, which are a vastly preferable way of distributing company resources to the shareholders from a tax perspective.

William J. Bernstein is principal at Efficient Frontier Advisors, LLC, Eastford, Connecticut. Robert D. Arnott is chairman of First Quadrant, LP, and Research Affiliates, LLC, Pasadena, California.

Note: This article was accepted for publication prior to Mr. Arnott's appointment as editor of the Financial Analysts Journal.

True, except that over the long term, net buybacks (that is, buybacks minus new issuance and options) have been reliably negative.

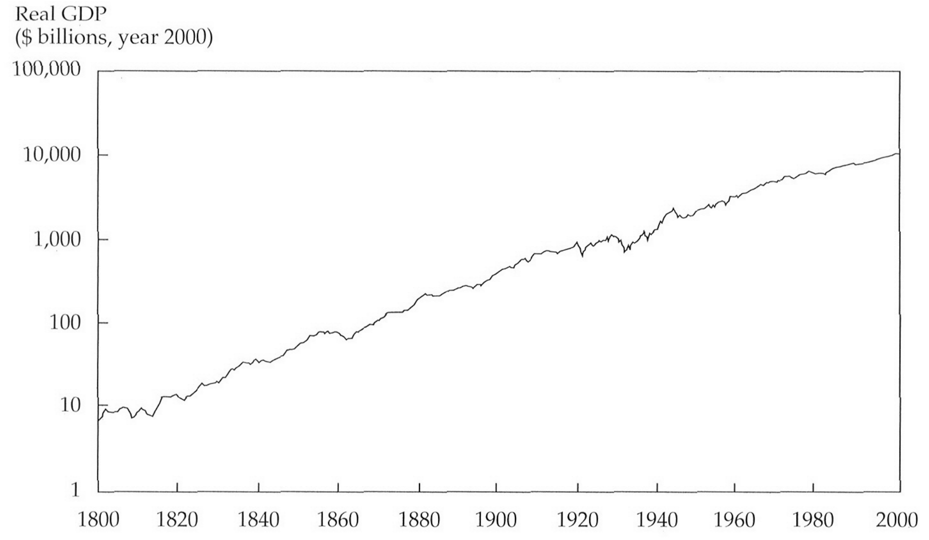
The vast majority of the institutional investing community has believed these untruths and has acted accordingly. Whether these tales are lies or merely errors, our implied indictment of these misconceptions is a serious one—demanding data. This article examines some of the data.

Big Lie #1: Rapid Earnings Growth

In the past two centuries, common stocks have provided a sizable risk premium to U.S. investors: For the 200 years from 1802 through 2001 (inclusive), the returns for stocks, bonds, and bills were, respectively, 8.42 percent, 4.88 percent, and 4.21 percent. In the most simplistic terms, the reason is obvious: A bill or a bond is a promise to pay interest and principal, and as such, its upside is sharply limited. Shares of common stock, however, are a claim on the future dividend stream of the nation's businesses. While the investor in fixed-income securities is receiving a modest fixed trickle from low-risk securities, the shareholder is the beneficiary of the ever-increasing fruits of innovation-driven economic growth.

Viewed over the decades, the powerful U.S. economic engine has produced remarkably steady growth. **Figure 1** plots the real GDP of the United States since 1800 as reported by the U.S. Department

Figure 1. Real U.S. GDP Growth, 1800–2000



of Commerce. From that year to 2000, the economy as measured by real GDP, averaging about 3.7 percent growth a year, has grown a thousandfold. The long-term uniformity of economic growth demonstrated in Figure 1 is both a blessing and a curse. To know that real U.S. GDP doubles every 20 years is reassuring. But it is also a dire warning to those predicting a rapid acceleration of economic growth from the computer and Internet revolutions. Such extrapolations of technology-driven increased growth are painfully oblivious to the broad sweep of scientific and financial history, in which innovation and change are constant and are neither new to the current generation nor unique.

The impact of recent advances in computer science pales in comparison with the technological explosion that occurred between 1820 and 1855. This earlier era saw the deepest and most far reaching technology-driven changes in everyday existence ever seen in human history. The changes profoundly affected the lives of those from the top to the bottom of the social fabric in ways that can scarcely be imagined today. At a stroke, the speed of transportation increased tenfold. Before 1820, people, goods, and information could not move faster than the speed of the horse. Within a generation, journeys that had previously taken weeks and months involved an order of magnitude less time, expense, danger, and discomfort. Moreover, important information that previously required the same long journeys could now be transmitted instantaneously.

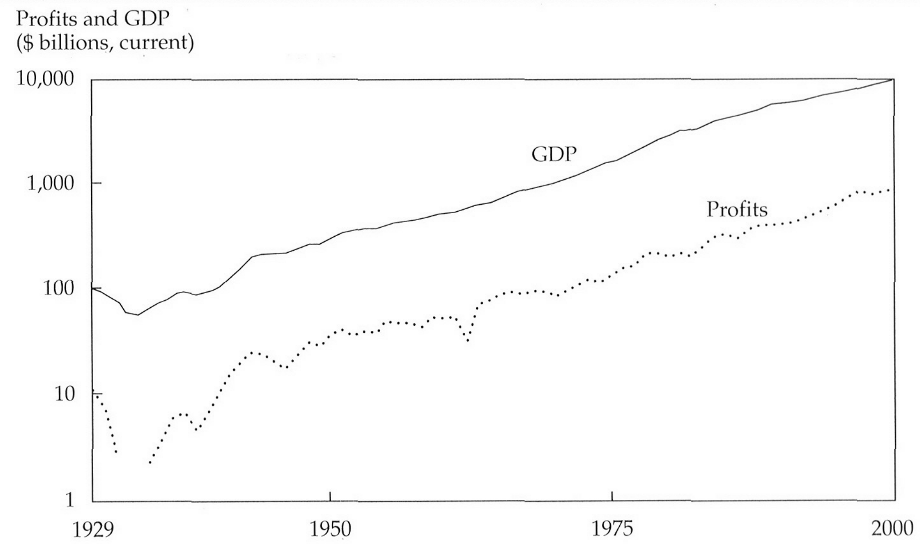
The average inhabitant of 1820 would have found the world 35 years later incomprehensible, whereas a person transported from 1967 to 2002 would have little trouble understanding the intervening changes in everyday life. From 1820 to 1855, the U.S. economy grew sixfold, four times the growth seen in the "tech revolution" of the past 35 years. More importantly, a close look at the right edge of Figure 1—the last decade of the 20th century—shows that the acceleration in growth during the "new paradigm" of the tech revolution of the 1990s was negligible when measured against the broad sweep of history.

The relatively uniform increase in GDP shown in Figure 1 suggests that corporate profits experienced a similar uniformity in growth. And, indeed, **Figure 2** demonstrates that, except for the Great Depression, during which overall corporate profits briefly disappeared, nominal aggregate corporate earnings growth has tracked nominal GDP growth, with corporate earnings remaining constant at 8–10 percent of GDP since 1929. The trend growth in corporate profits shown in Figure 2 is nearly identical, within a remarkable 20 bps, to the trend growth in GDP.[1]

Cannot stock prices also, then, be assumed to grow at the same rate as GDP? After all, a direct relationship between aggregate corporate profits and GDP has existed since at least 1929. The problem with this assumption is that per share earnings and dividends keep up with GDP *only if* no new shares are created. Entrepreneurial capitalism, however, creates a "dilution effect" through new enterprises and new stock in existing enterprises. So, per share earnings and dividends grow considerably slower than the economy.

In fact, since 1871, real stock prices have grown at 2.48 percent a year—versus 3.45 percent a year for GDP. Despite rising price–earnings ratios, we observe a "slippage" of 97 bps a year between stock

Figure 2. Nominal U.S. Corporate Profits and GDP, 1929–2000



prices and GDP. The true degree of slippage is much higher because almost half of the 2.48 percent rise in real stock prices after 1871 came from a substantial upward revaluation. The highly illiquid industrial stocks of the post–Civil War period rarely sold at more than 10 times earnings; often, they sold for multiples as low as 3 or 4 times earnings. These closely held industrial stocks gave way to instantly and cheaply tradable common shares, which today are priced nearly an order of magnitude more dearly.

Until the bull market of 1982–1999, the average stock was valued at 12–16 times earnings and 20–25 years' worth of dividends. By the peak of the bull market, both figures had tripled. Although the bull market was compressed into 18 years of the total period under discussion, this tripling of valuation levels was worth almost 100 bps a year—even when amortized over the full 130-year span. Thus, per share earnings and dividends grew 2 percent a year slower than the macroeconomy. If aggregate earnings and dividends grew as quickly as the economy while per share earnings and dividends were growing at an average of 2 percent a year slower, then shareholders have seen a slippage or dilution of 2 percent a year in the per share growth of earnings and dividends.

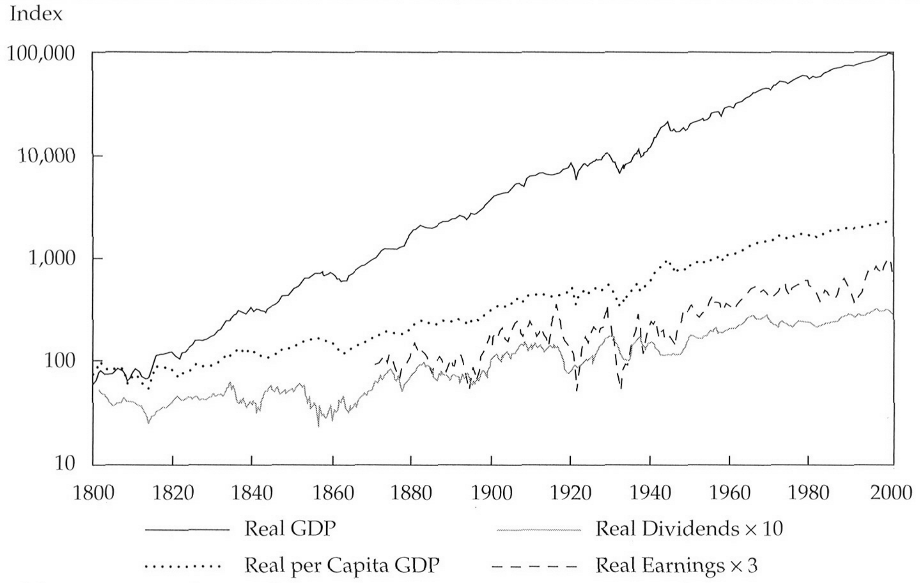
The dilution is the result of the net creation of shares as existing and new companies capitalize their businesses with equity. An often overlooked, but unsurprising, fact is that more than half of aggregate economic growth comes from new ideas and the creation of new enterprises, not from the growth of established enterprises. Stock investments can participate only in the growth of established businesses; venture capital participates only in the new businesses. The same investment capital cannot be simultaneously invested in both.

"Intrapreneurial capitalism," or the creation of new enterprises within existing companies, is a sound engine for economic growth, but it does not supplant the creation of new enterprises. Nor does it reduce the 2 percent gap between economic growth and earnings and dividend growth.

Note also that earnings and dividends grow at a pace very similar to that of per capita GDP (with some slippage associated with the "entrepreneurial" stock rewards to management). Consider that per capita GDP is a measure of productivity (with slight differences for changes in the work force) and aggregate economic wealth per capita can grow only in close alignment with productivity growth. Productivity growth is also the key driver of per capita income and of per share earnings and dividends. Accordingly, no one should be surprised that *per capita GDP, per capita income, per share earnings, and per share dividends—all grow in reasonably close proportion to productivity growth.*

If earnings and dividends grow faster than productivity, the result is a migration from return on labor to return on capital; if earnings and dividends grow more slowly, by a margin larger than the stock awards to management, then the economy migrates from rewarding capital to rewarding labor. Either way, such a change in the orientation of the economy cannot continue indefinitely. **Figure 3** demonstrates the close link between the growth of real corporate earnings and dividends and the growth of real per capita GDP; note that all of these measures exhibit growth far below the growth of real GDP.

Figure 3. Link of U.S. Earnings and Dividends to Economic Growth, 1802–2001



Note: Real GDP, real per capita GDP, and real stock prices were all constructed so that the series are on a common basis of January 1802 = 100.

A Global Laboratory

Is the United States unique? For an answer, we compared dividend growth, price growth, and total return with data on GDP growth and per capita GDP growth for the 16 countries covered by Dimson, Marsh, and Staunton (2002) spanning the 20th century.[2] The GDP data came from Maddison's (1995, 2001) world GDP survey for 1900–1998 and International Finance Corporation data for 1998–2000. The interrelationships of the data shown in **Table 1** are complex:

- The first column contains the real return (in U.S. dollars) of each national stock market.
- The second is real per share dividend growth.
- The third is real aggregate GDP growth for each nation (measured in U.S. dollars).
- The fifth is growth of real per capita GDP (measured in U.S. dollars).
- Thus, the fourth column measures the gap between growth in per share dividends and aggregate GDP—an excellent measure of the leakage that occurs between macroeconomic growth and the growth of stock prices.
- The last column represents the gap between the growth in per share dividends and per capita GDP.

For the full 16-nation sample in Table 1, the average gap between dividend growth and the growth in aggregate GDP is a startling 3.3 percent. The annual shortfall between dividend growth and per capita GDP growth is still 2.4 percent.

The 20th century was not without turmoil. Therefore, we divided the 16 nations into two groups according to the degree of devastation visited upon them by the era's calamities. The first group suffered substantial destruction of the countries' productive physical capital at least once during the century; the second group did not.

The nine nations in Group 1—Belgium, Denmark, France, Germany, Italy, Japan, the Netherlands, Spain, and the United Kingdom—were devastated by one or both of the two world wars or by civil war. The remaining seven—Australia, Canada, Ireland, South Africa, Sweden, Switzerland, and the United States—suffered relatively little direct damage. Even in this fortunate group, Table 1 shows dividend growth that is 2.3 percent less than GDP growth and 1.1 percent less than per capita GDP growth, on average. These gaps are close to the 2.7 percent and 1.4 percent figures observed in the United States during the 20th century.

The data for nations that were devastated during World Wars I and II and the Spanish Civil War are even more striking: The good news is that the economies in Group 1 repaired the devastations wrought by the 20th century; they enjoyed overall GDP growth and per capita GDP growth that rivaled the growth of the less-scarred Group 2 nations. The bad news is that the same cannot be said for per share equity performance; a 4.1 percent slippage occurred between the growth of their economies and per share corporate payouts. The

Table 1. Dilution of GDP Growth as It Flows Through to Dividend Growth: 16 Countries, 1900–2000

Country	Constituents of Real Stock Returns: Real Return	Constituents of Real Stock Returns: Dividend Growth	Real GDP Growth	Dilution in Dividend Growth (vis-à-vis GDP growth)	Real per Capita GDP Growth	Dilution in Dividend Growth (vis-à-vis per capita GDP growth)
Australia	7.5%	0.9%	3.3%	–2.4%	1.6%	–0.7%
Belgium	2.5	–1.7	2.2	–3.9	1.8	–3.5
Canada	6.4	0.3	4.0	–3.7	2.2	–1.9
Denmark	4.6	–1.9	2.7	–4.6	2.0	–3.9
France	3.6	–1.1	2.2	–3.3	1.8	–2.9
Germany	3.6	–1.3	2.6	–3.9	1.6	–2.9
Ireland	4.8	–0.8	2.3	–3.1	2.1	–2.9
Italy	2.7	–2.2	2.8	–5.0	2.2	–4.4
Japan	4.2	–3.3	4.2	–7.5	3.1	–6.4
Netherlands	5.8	–0.5	2.8	–3.3	1.7	–2.2
South Africa	6.8	1.5	3.4	–1.9	1.2	0.3
Spain	3.6	–0.8	2.7	–3.5	1.9	–2.7
Sweden	7.6	2.3	2.5	–0.2	2.0	0.3
Switzerland	5.0	0.1	2.5	–2.4	1.7	–1.6
United Kingdom	5.8	0.4	1.9	–1.5	1.4	–1.0
United States	6.7	0.6	3.3	–2.7	2.0	–1.4
Full-sample average	5.1	–0.5	2.8	–3.3	1.9	–2.4
War-torn Group 1 average	4.0	–1.4	2.7	–4.1	1.9	–3.3
Non-war-torn Group 2 average	6.4	0.7	3.0	–2.3	1.8	–1.1

creation of new enterprises in the wake of war was an even more important engine for economic recovery than in the Group 2 nations.

Thus, in Group 2 "normal nations" (i.e., those untroubled by war, political instability, and government confiscation of wealth), the natural ongoing capitalization of new technologies apparently produces a net dilution of outstanding shares of slightly more than 2 percent a year. The Group 1 nations scarred badly by war represent a more fascinating phenomenon; they can be thought of as experiments of nature in which physical capital is devastated and must be rebuilt. Fortunately, destroying a nation's intellectual, cultural, and human capital is much harder than destroying its economy; within little more than a generation, the GDP and per capita GDP of war-torn nations catch up with, and in some cases surpass, those of the undamaged nations. Unfortunately, the effort requires a high rate of equity recapitalization, which is reflected in the substantial dilution seen in Table 1 for the war-torn countries. This recapitalization savages existing shareholders.

In short, the U.S. experience was not unique. Around the world, every one of these countries except Sweden experienced dividend growth sharply slower than GDP growth, and only two countries experienced dividend growth even slightly faster than per capita GDP growth. The U.S. experience was better than most and was similar to that of the other nations that were not devastated by war.

The data for the individual countries in Table 1 show that the average real growth in dividends was negative for most countries. It also shows that dilution of GDP growth (the fourth column) was substantial for all the countries studied and that dilution of per capita GDP growth (the last column) was substantial for most countries but fit dividend growth with much less "noise" than did the dilution of overall GDP growth.

This analysis has disturbing implications for "paradigmistas" convinced of the revolutionary nature of biotechnology, Internet, and telecommunications/broadband companies. A rapid rate of technological change may, in effect, turn "normal" Group 2 nations into strife-torn Group 1 nations: An increased rate of obsolescence effectively destroys the economic value of plant and equipment as surely as bombs and bullets, with the resultant dilution of per share payouts happening much faster than the technology-driven acceleration of economic growth—if such acceleration exists. How many of the paradigmistas truly believe that the tech revolution will benefit the shareholders of existing enterprises remotely as much as it can benefit the entrepreneurs creating the new enterprises that make up the vanguard of this revolution?

Whatever the true nature of the interaction of technological progress and per share earnings, dividends, and prices, it will come as an unpleasant surprise to many that even in the Group 2 nations, average real per share dividend growth was only 0.66 percent a year (rounded in Table 1 to 0.7 percent); for the war-torn Group 1 nations, it was disturbingly negative.

In short, the equity investor in a nation blessed by prolonged peace cannot expect a real return greatly in excess of the much-maligned dividend yield; the investor cannot expect to be rescued by more rapid economic growth. Not only is outsized economic growth unlikely to occur, but even if it does, its benefits will be more than offset by the dilution of the existing investor's ownership interest by technology-driven increased capital needs.

Big Lie #2: Stock Buybacks

Stock buybacks are attractive to companies and beneficial to investors. They are a tax-advantaged means of providing a return on shareholder capital and preferable to dividends, which are taxed twice. Buybacks have enormous appeal. But contrary to popular belief, they did not occur in any meaningful way in the 1990s.

To support this contention, we begin with a remarkably simple measure of slippage in per share earnings and dividend growth: the ratio of the proportionate increase in market capitalization to the proportionate increase in stock price. For example, if over a given period, the market cap increases by a factor of 10 and the cap-weighted price index increases by a factor of 5, a 100 percent net share issuance has taken place in the interim. Formally,

$$\text{Net dilution} = \left(\frac{1+c}{1+r}\right) - 1,$$

where c is capitalization increase and r is price return. This relationship has the advantage of factoring out valuation changes, which are embedded in both the numerator and denominator, and neutralizing the impact of stock splits. Furthermore, it holds only for universal market indexes, such as the CRSP 1–10 or the Wilshire 5000, because less inclusive indexes can vary the ratio simply by adding or dropping securities. **Figure 4** contains plots of the total market cap and price indexes of the CRSP 1–10 beginning at the end of 1925.

The CRSP data contained NYSE-listed stocks until 1962. Even the CRSP data, however, can involve adding securities: CRSP added the Amex stocks in July 1962 and the Nasdaq stocks in July 1972, which created artificial discontinuities on those dates. The adjustment for these shifts is evident in **Figure 5**, for which we held the dilution ratio constant during the two months in question.[3] Note how market cap slowly and gradually pulls away from market price. The gap does not look large in Figure 4, but by the end of 2001, the cap index had grown 5.49 times larger than the price index, suggesting that for every share of stock extant in 1926, 5.49 shares existed in late 2001. The implication is that net new share issuance occurred at an annualized rate of 2.3 percent a year. Note that this rate is identical to the average dilution for non-war-torn countries during the 20th century given in Table 1. To give a better idea of how this dilution has proceeded over the past 75 years, Figure 5 provides a dilution index, defined as the ratio of capitalization growth to price index growth.

Figure 4. CRSP 1–10 Market Cap and Price Indexes, 31 December 1925–June 2002

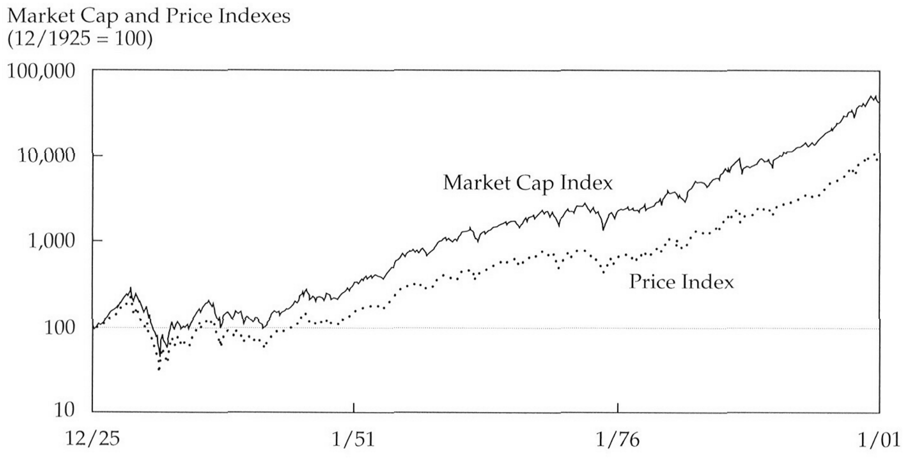


Figure 5. Cumulative Excess Growth of Market Cap Relative to Price Index, 31 December 1925 through June 2002

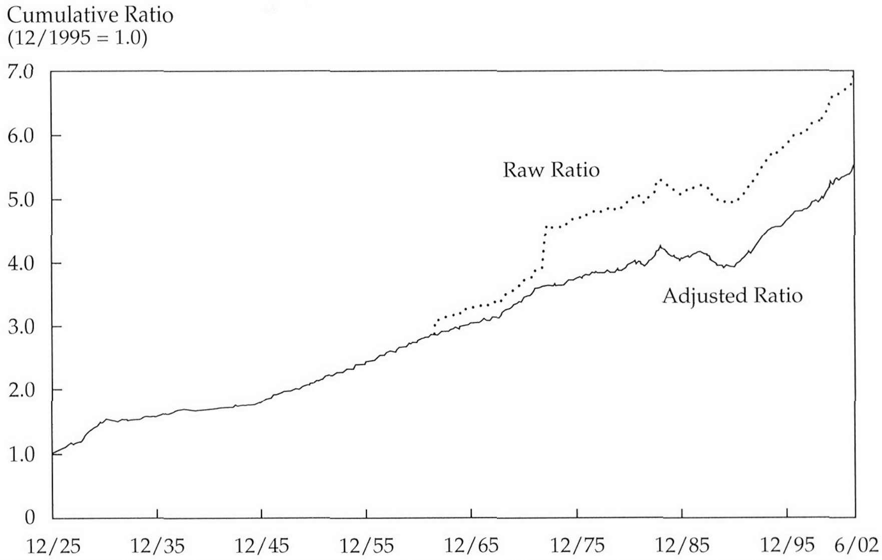
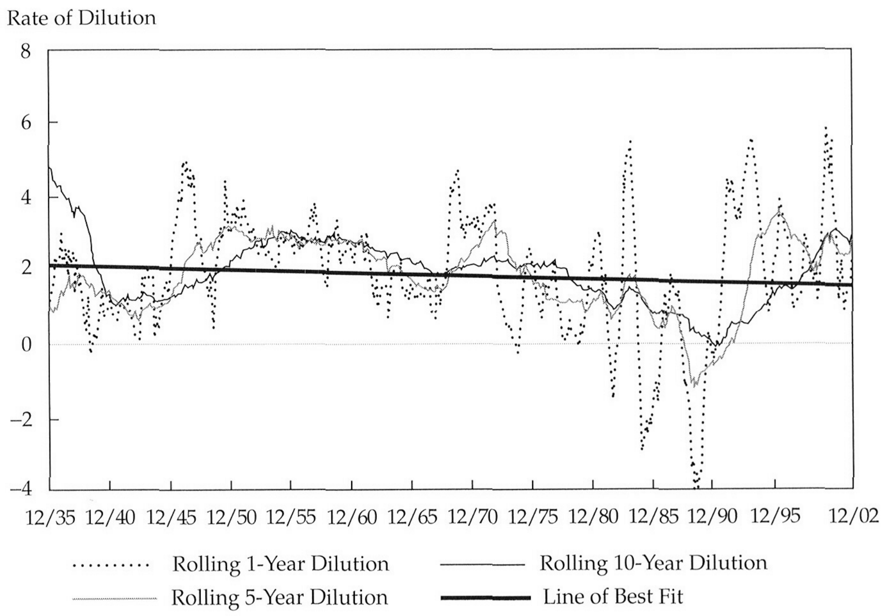


Figure 5 traces the growth in the ratio of the capitalization of the CRSP 1–10 Index as compared with the market-value-weighted price appreciation of these same stocks. The fact that this line rises nearly monotonically shows clearly that new-share issuance almost always sharply exceeds stock buybacks. The notable exception occurred in the late 1980s, when buybacks modestly outpaced new share issuance (evident from the fact that the line falls slightly during these "Milken years"). This development probably played a key role in precipitating the popular illusion that buybacks were replacing dividends. For a time, they did. But that stock buybacks were an important force in the 1990s is simply a myth. And belief in the myth may have been an important force in the bull market of the 1990s.

Figure 6 shows the rolling 1-year, 5-year, and 10-year dilution effect on existing equity shareholders as a consequence of a growth in the aggregate

Figure 6. Annualized Rate of Shareholder Dilution, 31 December 1935 through June 2002



supply of equity shares. Keep in mind that every 1 percent rise in equity capital is a 1 percent rise in market cap in which existing shareholders did not (could not) participate. Aside from the 1980s, this dilution effect on shareholders was essentially never negative—not even on a one-year basis. One can see how the myth of stock buybacks gained traction after the 1980s; even the 10-year average rate of dilution briefly dipped negative in the late 1980s. But then, during the late 1990s, stock buybacks were outstripped by new share issuance at a pace that was only exceeded in the IPO binge of 1926–1930. These conclusions hold true whether one is looking at net new share issuance on a 1-year, 5-year, or 10-year basis.

Those who argue that stock buybacks will allow future earnings growth to exceed GDP growth can draw scant support from history. Investors did see enormous earnings growth, far faster than real economic growth, from 1990 to 2000. But Figure 3 shows how tiny that surge of growth was in the context of 130 years of earnings history. Much of the earnings surge of the 1990s was dubious, at best.

The Eye of the Storm?

The big question today is whether the markets are likely to rebound into a new bull market or have merely been in the eye of the storm. We think the markets are in the eye.

The rapid earnings growth of the 1990s, which many pointed to as "proof" of a new paradigm, had several interesting characteristics:

1. A trough in earnings in the 1990 recession transformed into a peak in earnings in the 2000 bubble. Measuring growth from trough to peak is an obvious error; extrapolating that growth is even worse. This decade covered a large chunk of the careers of most people on Wall Street, many of whom have come to believe that earnings can grow very fast for a very long time. Part of conventional wisdom now is that earnings growth can outstrip macroeconomic growth.
2. Influenced by the new paradigm, analysts frequently ignored write-offs to focus increasingly on operating earnings. This practice is acceptable if write-offs are truly "extraordinary items," but it is not acceptable if write-offs become a recurring annual or biannual event, as was commonplace in the 1990s. Furthermore, what are extraordinary items for a single company are entirely ordinary for the economy as a whole. In some companies and some sectors, write-offs are commonplace. The focus on operating earnings for the broad market averages is misguided at best and deceptive at worst.
3. Those peak earnings of 1999–2000 consisted of three dubious components. The first is an underrecognition of the impact of stock options, which various Wall Street strategists estimated at 10–15 percent of earnings. The second is pension expense (or pension "earnings") based on assumptions of a 9.5 percent return, which were realistic then but are no longer; this factor pumped up earnings by approximately 15 percent at the peak and 20–30 percent from current depressed levels. The third component is Enron-style "earnings management," which various observers have estimated to be 5–10 percent of the peak earnings. (We suspect this percentage will turn out to be conservative.)

If these three sources of earnings overstatement (aggressive pension accounting, failure to expense management stock options, and outright fraud) are removed, the \$54 peak earnings per share for the S&P 500 Index in 2000 turn out to be closer to \$36. This figure implies normalized earnings a notch lower still. If the normalized earnings for the S&P 500 are in the \$30–\$36 range, as we suspect is the case, then the market at mid-year 2003 was still at a relatively rich 27–32 times normalized earnings. Using Shiller's (2000) valuation model (real S&P 500 level divided by 10-year average of real reported earnings) confirms this analysis. Shiller's model pegs the current multiple at nearly 30 times normalized earnings in mid-2003.

In principle, several conditions could allow earnings growth to exceed GDP growth. Massive stock buybacks are one. But we have demonstrated that buybacks in the 20th century were far more smoke than fire. Buybacks have been much touted as the basis for sustained earnings growth at unprecedented rates, but they simply do not show up in the data on market capitalization relative to market index price levels. Cross-holdings could also offer an interesting complication. But again, their impact does not show up in the objective shareholder dilution data. We have demonstrated that buybacks and cross-holdings do not yet show any signs of offsetting the historical 2 percent dilution, but the exploration of the possible impact of buybacks and cross-holdings is beyond the scope of this study.

Conclusion

Expected stock returns would be agreeable if dividend growth, and thus price growth, proceeded at the same rate as, or a higher rate than, aggregate economic growth. Unfortunately, dividends do not grow at such a rate: When we compared the Dimson et al. 20th century dividend growth series with aggregate GDP growth, we found that even in nations that were not savaged by the century's tragedies, dividends grew 2.3 percent more slowly, on average, than GDP. Similarly, by measuring the gap between the growth of market cap and share prices in the CRSP database, we found that between 1926 and the present, a 2.3 percent net annual dilution has occurred in the outstanding number of shares in the United States.

Two independent analytical methods point to the same conclusion: In stable nations, a roughly 2 percent net annual creation of new shares—the Two Percent Dilution—leads to a separation between long-term economic growth and long-term growth in dividends per share, earnings per share, and share price.

The markets are probably in the eye of a storm and can expect further turmoil as the rest of the storm passes over. If normalized S&P 500 earnings are $30–$36 per share, if payout ratios on those normalized earnings are at the low end of the historical range (implying lower-than-normal future earnings growth), if normal earnings growth is really only about 1 percent a year above inflation, if stock buybacks have been little more than an appealing fairy tale, if the credibility of earnings is at an all-time low, and if demographics suggest Baby Boomer dis-saving in the next 20 years, then we have a problem.

The authors would like to acknowledge the help, suggestions, and encouragement of Cliff Asness, Peter Bernstein, and Max Darnell.

Notes

1. In calculating "trend growth," we used a loglinear line of best fit to minimize the impact of distortions from an unusually high or low starting or ending date. The loss years of 1932 and 1933 were excluded because of loglinear calculation.
2. The Dimson et al. book is a masterwork. If you do not have a copy, you should.
3. We assumed the dilution factor to be zero in those two months. If a massive stock buyback or a massive new IPO occurred during one of these two months, we may have missed it. But net buybacks or net new share issuance during months in which the "index" saw a major reconstitution would be difficult to measure.

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alternative investment vehicles has recently been documented, no such evidence is available on the ability of investors to generate superior risk-adjusted returns based on timing among various hedge fund styles.

This article is, to the best of our knowledge, the first to document the existence of predictability in hedge fund index returns and to focus on its implications for tactical allocation decisions. Specifically, we examined (lagged) multifactor models for the return on nine hedge fund indexes. We chose factors that would measure the many dimensions of financial risk—market risks (proxied by stock prices, interest rates, and commodity prices), volatility risk (proxied by implicit volatilities from option prices), default risk (proxied by default spreads), and liquidity risk (proxied by trading volume). We show that a parsimonious set of models captures a significant amount of predictability for most hedge fund styles.

We also found that the benefits of tactical style allocation are potentially enormous. The article first provides evidence of the economic significance of the performance of hedge fund style-timing models by comparing the performance of a market timer with perfect forecasting ability in the alternative investment universe with the performance of a perfect market timer in the traditional universe. Then, the performance of a realistic style-timing model is presented. An equity-oriented portfolio that mixed traditional and alternative investment vehicles and a similar debt-oriented mixed portfolio produced spectacular results. Moreover, the results do not seem to be significantly affected by the presence of reasonably high transaction costs.

Some specific features of hedge fund investing do not facilitate the implementation of tactical allocation strategies. In particular, the absence of liquidity and the presence of lockup periods, which are typical of investments in hedge funds, are likely to prevent investors from implementing any kind of dynamic allocation among funds. We believe, however, that the future of hedge fund style timing is even brighter than its past or present. The hedge fund industry is still relatively new, and market conditions are evolving at an astounding pace. Although the world of alternative investing has consisted of a disparate set of managers following disparate specific strategies, significant attempts at structuring the markets have occurred in the past few years. Important, well-established firms are creating relatively liquid investment products designed to track the performance of hedge fund indexes. ⊠

Keywords: Alternative Investments: hedge fund strategies; Portfolio Management: asset allocation; Portfolio Management: hedge fund strategies

Earnings Growth: The Two Percent Dilution page 47

William J. Bernstein and Robert D. Arnott

The bull market of the 1990s was built largely on a foundation of two immense misconceptions:

- With a technology revolution and a "new paradigm" of low payout ratios and internal reinvestment, earnings will grow faster than ever before. Five percent real growth will be easy to achieve.
- When earnings are not distributed as dividends and not reinvested into stellar growth opportunities, they are distributed back to shareholders in the form of stock buybacks.

In fact, neither of these widespread beliefs stands up to historical scrutiny. Since 1800, the economy, as measured by real GDP, has grown a thousandfold, averaging about 3.7 percent a year. The long-term uniformity of economic growth is remarkable; it is both a blessing and a curse. To know that real U.S. GDP doubles every 20 years is reassuring. But this growth is also a dire warning to those predicting rapid acceleration of economic growth from the computer and Internet revolutions.

The relatively uniform increase in GDP implies a similar uniformity in the growth of corporate profits—which does, in fact, occur. Except for the Great Depression, during which overall corporate profits briefly disappeared, nominal aggregate corporate earnings have tracked nominal GDP growth, with corporate earnings staying at 8–10 percent of the GDP growth. The trend growth in corporate profits is identical, to within a remarkable 20 bps, to the trend growth in GDP.

For 16 countries, with data spanning the 20th century, we compared dividend growth, price growth, and total return with GDP data from the same period. We found that in stable, non-war-torn nations, per share dividend growth was 2.3 percent less than growth in aggregate GDP and 1.1 percent less than growth in per capita GDP. In the war-torn nations, the situation was far worse—per share dividend growth 4.1 percent less than growth in aggregate GDP and 3.3 percent less than growth in per capita GDP.

Data for the comprehensive CRSP 1–10 Index from 1926 to June 2002 show that, after adjustment for additions to the index, total U.S. market capitalization grew 2.3 percent faster than the price index. Thus, over the past 76 1/2 years, a 2.3 percent net new issuance of shares took place, which is the equivalent of *negative* buybacks. Although net buybacks occurred in the 1980s, by the 1990s, buyback activity had once again returned to historical norms.

Earnings growth was indeed high during the 1990s. But the persistence of this growth is dubious for three reasons:

- The market went from trough earnings in the 1990 recession to peak earnings in the 2000 bubble. Measuring growth from trough to peak is meaningless; extrapolating that growth is even worse.
- Analysts frequently ignored write-offs while increasing their focus on operating earnings. This behavior is acceptable if write-offs are truly "extraordinary items" but not if write-offs become an annual or biannual event, as was commonplace in the 1990s. Furthermore, what are extraordinary items for a single company are entirely ordinary for the economy as a whole.
- The peak earnings of 1999–2000 consisted of three dubious components. The first was an underrecognition of the impact of stock options, which various Wall Street strategists estimated at 10 percent or more of earnings. The second was pension expense (or pension "earnings") based on 9–10 percent return assumptions, which were realistic then but are no longer; this factor pumped up earnings by about 15 percent at the peak and 20–30 percent from recent, depressed levels. The third was Enron-style "earnings management," which various observers have estimated at 5–10 percent of the peak earnings.

In summary, in a dynamic, free-market economy, considerable capital is consumed funding new ventures. For this reason, per share growth of prices, earnings, and dividends will lag aggregate macroeconomic growth by an amount equal to the net issuance of new shares. In peaceful, stable societies, this gap appears to be about 2 percent a year. In war-torn nations, this gap is considerably larger. Although these nations' economies can recover relatively rapidly, the high degree of recapitalization that is required savages shareholders.

Keywords: Portfolio Management: asset allocation; Economics: macroeconomics; Investment Industry: future directions and sources of change

Outlier-Resistant Estimates of Beta

page 56

R. Douglas Martin and Timothy T. Simin

Recent surveys show that many analysts continue to use the capital asset pricing model and that most of them purchase betas from commercial providers, which invariably use a raw or adjusted ordinary least-squares estimate of beta. The sanctified use of OLS is justified by the fact that the OLS beta is statistically the best estimate of the linear model parameters under idealized assumptions.

In practice, however, one of the ways these assumptions fail is associated with the occurrence of a small fraction of exceptionally large or small returns—that is, outliers. We show by using several examples that outliers can, depending on their location in the equity-market-returns space, substantially bias OLS estimates of beta. Furthermore, the weekly returns for 8,314 companies from the CRSP database that had at least two years of returns in the period January 1992 through December 1996 contained many examples in which the deletion of a few outliers, sometimes even a single outlier, dramatically affected the OLS beta.

The vast majority of commercial providers do nothing to deal with outliers; the few that do deal with this problem use some form of outlier treatment without a solid statistical rationale. We deal with the vulnerability of the OLS beta to outliers by introducing a new beta estimate that is resistant to the types of outliers that cause the most bias in OLS estimates but that produces estimates similar to OLS for outlier-free data. The outlier-resistant beta is an intuitively appealing weighted-least-squares estimate with data-dependent weights. It has several advantages over other commonly used "robust" techniques.

The outlier-resistant beta applied to the CRSP database shows that the absolute value of the difference between the resistant and OLS betas is greater than 0.5 for 13 percent of the companies and that this difference is considerably larger than 1.0 for 3.2 percent of the companies. Such extreme sensitivity of the OLS beta to outliers results in misleading interpretations of the risk and return characteristics of a company. This study shows that outlier distortion of the OLS beta is primarily a small-firm effect (i.e., there is a monotonic relationship between the median market capitalization of companies and the absolute difference between the resistant and OLS betas). Furthermore, the resistant beta has superior performance relative to the OLS beta for predicting future betas when influential outliers are present but suffers (at most) only a slight degradation in performance when no influential outliers are present.

What Risk Premium Is "Normal"?

Robert D. Arnott and Peter L. Bernstein

The goal of this article is an estimate of the objective forward-looking U.S. equity risk premium relative to bonds through history—specifically, since 1802. For correct evaluation, such a complex topic requires several careful steps: To gauge the risk premium for stocks relative to bonds, we need an expected real stock return and an expected real bond return. To gauge the expected real bond return, we need both bond yields and an estimate of expected inflation through history. To gauge the expected real stock return, we need both stock dividend yields and an estimate of expected real dividend growth. Accordingly, we go through each of these steps. We demonstrate that the long-term forward-looking risk premium is nowhere near the level of the past; today, it may well be near zero, perhaps even negative.

The investment management industry thrives on the expedient of forecasting the future by extrapolating the past. As a consequence, U.S. investors have grown accustomed to the idea that stocks "normally" produce an 8 percent real return and a 5 percent (that is, 500 basis point) risk premium over bonds, compounded annually over many decades.[1] Why? Because long-term historical returns have been in this range with impressive consistency. And because investors see these same long-term historical numbers year after year, these expectations are now embedded in the collective psyche of the investment community.[2]

Both the return and the risk premium assumptions are unrealistic when viewed from current market levels. Few have acknowledged that an important part of the lofty real returns of the past stemmed from rising valuation levels and from high dividend yields, which have since diminished. As we will demonstrate, the long-term forward-looking risk premium is nowhere near the 5 percent level of the past; indeed, today, it may well be near zero, perhaps even negative. Credible studies in and outside the United States are challenging the flawed conventional view. Well-researched studies by Claus and Thomas (2001) and Fama and French (2000) are just two (see also Arnott and Ryan 2001). Similarly, the long-term forward-looking real return from stocks is nowhere near history's 8 percent. We argue that, barring unprecedented economic growth or unprecedented growth in earnings as a percentage of the economy, real stock returns will probably be roughly 2–4 percent, similar to bond returns. In fact, even this low real return figure assumes that current near-record valuation levels are "fair" and likely to remain this high in the years ahead. "Reversion to the mean" would push future real returns lower still.

Furthermore, if we examine the historical record, neither the 8 percent real return nor the 5 percent risk premium for stocks relative to government bonds has ever been a realistic *expectation*, except from major market bottoms or at times of crisis, such as wartime. But this topic merits careful exploration. After all, according to the Ibbotson Associates data, equity investors earned 8 percent real returns and stocks have outpaced bonds by more than 5 percent over the past 75 years. Intuition suggests that investors should not require such outsized returns in order to bear equity market risk. Should investors have expected these returns in the past, and why shouldn't they continue to do so? We examine these questions expressed in a slightly different way. First, can we derive an objective estimate of what investors had good reasons to expect in the past? Second, why should we expect less in the future than we have earned in the past?

The answers to both questions lie in the difference between the *observed* excess return and the *prospective* risk premium, two fundamentally different concepts that, unfortunately, carry the same label—risk premium. If we distinguish between past excess returns and future expected risk premiums, the idea that future risk premiums should be different from past excess returns is not at all unreasonable.[3]

Robert D. Arnott is managing partner at First Quadrant, L.P., Pasadena, California. Peter L. Bernstein is president of Peter L. Bernstein, Inc., New York.

This complex topic requires several careful steps if it is to be evaluated correctly. To gauge the risk premium for stocks relative to bonds, we need an expected real bond return and an expected real stock return. To gauge the expected real bond return, we need both bond yields and an estimate of expected inflation through history. To gauge the expected real stock return, we need both stock dividend yields and an estimate of expected real dividend growth. Accordingly, we go through each of these steps, in reverse order, to form the building blocks for the final goal—an estimate of the objective forward-looking equity risk premium relative to bonds through history.

Has the Risk Premium Natural Limits?

For equities to have a zero or negative risk premium relative to bonds would be unnatural because stocks are, on average over time, more volatile than bonds. Even if volatility were not an issue, stocks are a secondary call on the resources of a company; bondholders have the first call. Because the risk premium is usually measured for corporate stocks as compared with government debt obligations (U.S. T-bonds or T-bills), the comparison is even more stark. Stocks should be priced to offer a superior return relative to *corporate* bonds, which should offer a premium yield (because of default risk and tax differences) relative to T-bonds, which should typically offer a premium yield (because of yield-curve risk) relative to T-bills. After all, long bonds have greater duration—hence, greater volatility of price in response to yield changes—so a capital loss is easier on a T-bond than on a T-bill.

In other words, the current circumstance, in which stocks appear to have a near-zero (or negative) risk premium relative to government bonds, is abnormal in the extreme. Even if we add 100 bps to the risk premium to allow for the impact of stock buybacks, today's risk premium relative to the more relevant corporate bond alternatives is still negligible or negative. This facet was demonstrated in Arnott and Ryan and is explored further in this article.

If zero is the natural minimum risk premium, is there a natural maximum? Not really. In times of financial distress, in which the collapse of a nation's economy, hyperinflation, war, or revolution threatens the capital base, expecting a large reward for exposing capital to risk is not unreasonable. Our analysis suggests that the U.S. equity risk premium approached or exceeded 10 percent during the Civil War, during the Great Depression, and in the wake of World Wars I and II. That said, however, it is difficult to see how one might objectively measure the forward-looking risk premium in such conditions.

A 5 percent excess return on stocks over bonds compounds so mightily over long spans that most serious fiduciaries, if they believed stocks were going to earn a 5 percent risk premium, would not even consider including bonds in a portfolio with a horizon of more than a few years: The probabilities of stocks outperforming bonds would be too high to resist.[4] Hence, under so-called normal conditions—encompassing booms and recessions, bull and bear markets, and "ordinary" economic stresses—a good explanation is hard to find for why expected long-term real returns should ever reach double digits or why the expected long-term risk premium of stocks over bonds should ever exceed about 5 percent. These upper bounds for expected real returns or for the risk premium, unlike the lower bound of zero, are "soft" limits; in times of real crisis or distress, the sky's the limit.

Expected versus "Hoped-For" Returns

Throughout this article, we deal with *expected* returns and *expected* risk premiums. This concept is rooted in objective data and defensible expectations for portfolio returns, rather than in the returns that an investor might *hope* to earn. The distinction is subtle; both represent expectations, but one is objective and the other subjective. Even at times in the past when valuation levels were high and when stockholders would have had no objective reason to expect any growth in real dividends over the long run, hopes of better-than-market short-term profits have always been the primary lure into the game.[5]

When we refer to expected returns or expected risk premiums, we are referring to the estimated future returns and risk premiums that an objective evaluation—based on past rates of growth of the economy, past and prospective rates of inflation, current stock and bond yields, and so forth—might have supported at the time. We explicitly do not include any extrapolation of past returns per se, because past returns are driven largely by changes in valuation levels (e.g., changes in yields), which in an efficient market, investors should not expect to continue into the indefinite future. By the same token, we explicitly do not presume any reversion to the mean, in which high yields or low yields are presumed to revert toward historical norms. We presume that the current yield is "fair" and is an unbiased estimator of future yields, both for stocks and bonds.

Few investors subjectively expect returns as low as the objective returns produced by this sort of analysis. In a recent study by Welch (2000), 236 financial economists projected, on average, a 7.2 percent risk premium for stocks relative to T-bills over the next 30 years. If we assume that T-bills offer the same 0.7 percent real return in the future that they have offered over the past 75 years, then stocks must be expected to offer a compounded geometric average real return of about 6.6 percent.[6] Given a dividend yield of roughly 1.5 percent in 1998–1999, when the survey was being carried out, the 236 economists in the survey were clearly presuming that dividend and earnings growth will be at least 5 percent a year above inflation, a rate of real growth three to five times the long-term historical norm and substantially faster than plausible long-term economic growth.

Indeed, even if ir vestors take seriously the real return estimates and risk premiums produced by the sort of objective analysis we propose, many of them will continue to believe that their own investments cannot fail to do better. Suppose they agree with us that stocks and bonds are priced to deliver 2–4 percent real returns before taxes.[7] Do they believe that *their* investments will produce such uninspired pretax real returns? Doubtful. If these kinds of projections were taken seriously, markets would be at far different levels from where they are. Consequently, if these objective expectations are correct, most investors will be wrong in their (our?) subjective expectations.

What Were Investors Expecting in 1926

Are we being reasonable to suggest that, after a 75-year span with 8 percent real stock returns and a 5 percent excess return over bonds (the Ibbotson findings), an 8 percent real return or a 5 percent risk premium is abnormal? Absolutely. The relevant question is whether the investors of 1926 would have had reason to *expect* these extraordinary returns. In fact, they would not. What they got was different from what they should have expected, which is a normal result in a world of uncertainty.

At the start of 1926, the beginning of the returns covered in the Ibbotson data, investors had no reason to expect the 8 percent real returns that have been earned over the past 75 years nor that these returns would provide a 5 percent excess return over bonds. As we will describe, these outcomes were the consequence of a series of historical accidents that uniformly helped stocks and/or helped the risk premium.

Consider what investors might objectively have expected at the start of 1926 from their long-term investments in stocks and bonds. In January that year, government bonds were yielding 3.7 percent. The United States was on a gold standard, government was small relative to the economy as a whole, and the price level of consumer goods, although volatile, had been trendless throughout most of U.S. history up to that moment; thus, inflation expectations were nil. It was a time of relative stability and prosperity, so investors would have had no reason to expect to receive less than this 3.7 percent government bond yield. Accordingly, the *real* return that investors would have expected on their government bonds was 3.7 percent, plain and simple.

Meanwhile, the dividend yield on stocks was 5.1 percent. We can take that number as the starting point to apply the sound theoretical notion that the real return on stocks is equal to

- the dividend yield
- plus (or minus) any change in the real dividend (now viewed as participation in economic growth)
- plus (or minus) any change in valuation levels, as measured by P/E multiples or dividend yields.

What did the investors expect of stocks in early 1926? The time was the tail end of the era of "robber baron" capitalism. As Chancellor (1999) observed, investors were accustomed to the fact that company managers would often dilute shareholders' returns if an enterprise was successful but that the shareholder was a full partner in any business decline. More important was the fact that the long-run history of the market was trendless. Thoughts of long-term economic growth, or long-run capital appreciation in equity holdings, were simply not part of the tool kit for return calculations in those days.

Investors generally did not yet consider stocks to be "growth" investments, although a few people were beginning to acknowledge the full import of Smith's extraordinary study *Common Stocks as Long-Term Investments*, which had appeared in 1924. Smith demonstrated how stocks had outperformed bonds over the 1901–22 period.[8] His work became the bible of the bulls as the bubble of the late 1920s progressed. Prior to 1926, however, investors continued to follow J.P. Morgan's dictum that the market would fluctuate, a traditional view hallowed by more than 100 years of stock market history. In other words, investors had no *trend* in mind. The effort was to buy low and to sell high, period.

Assuming that markets were fairly priced in early 1926, investors should have expected little or no benefit from rising valuation levels. Accordingly, the real long-term return that stock investors could reasonably have expected on average, or from the market as a whole, was the 5.1 percent dividend yield, give or take a little. Thus, stock investors would have expected roughly a 1.4 percent risk premium over bonds, not the 5 percent they actually earned in the next 75 years. The market exceeded objective expectations as a consequence of a series of historical accidents:

- *Historical accident #1: Decoupling yields from real yields.* The Great Depression (roughly 1929–1939) introduced a revolutionary increase in the role of government in peacetime economic policy and, simultaneously, drove the United States (and just about the rest of the world) off the gold standard. As prosperity came back in a big way after World War II, expected inflation became a normal part of bond valuation. This change created a one-time shock to bonds that decoupled nominal yields from real yields and drove nominal yields higher even as real yields fell. Real yields at year-end 2001 were 3.4 percent (the Treasury Inflation-Indexed Securities, commonly called TIPS, yield[9]), but nominal yields were 5.8 percent. This rise in nominal yields (with real yields holding steady) has cost bondholders 0.4 percent a year over 75 years. That accident alone accounts for nearly one-tenth of the 75-year excess return for stocks relative to bonds.
- *Historical accident #2: Rising valuation multiples.* Between 1926 and 2001, stocks rose from a valuation level of 18 times dividends to nearly 70 times dividends. This fourfold increase in the value assigned to each dollar of dividends contributed 180 bps to annual stock returns over the past 75 years, even though the entire increase occurred in the last 17 years of the period (we last saw 5.1 percent yields in 1984). This accident explains fully one-third of the 75-year excess return.
- *Historical accident #3: Survivor bias.* Since 1926, the United States has fought no wars on its own soil, nor has it experienced revolution. Four of the fifteen largest stock markets in the world in 1900 suffered a total loss of capital, a –100 percent return, at some point in the past century. The markets are China, Russia, Argentina, and Egypt. Two others came close—Germany (twice) and Japan. Note that war or revolution can wipe out bonds as easily as stocks (which makes the concept of "risk premium" less than relevant). U.S. investors in early 1926 would *not* have considered this likelihood to be zero, nor should today's true long-term investor.
- *Historical accident #4: Regulatory reform.* Stocks have gone from passing relatively little economic growth through to shareholders to passing much of the economic growth through to shareholders. This shift has led to 1.4 percent a year growth in real dividend payments and in real earnings since 1926. This accelerated growth in real dividends and earnings, which no one in 1926 could have anticipated, explains roughly one-fourth of the 75-year excess return.[10]

In short, the equity investors of 1926 probably expected to earn a real return little different from their 5.1 percent yield and expected to earn little more than the 140 bp yield differential over bonds. Indeed, an objective investor might have expected a notch less because of the greater frequency with which investors encountered dividend cuts in those days.

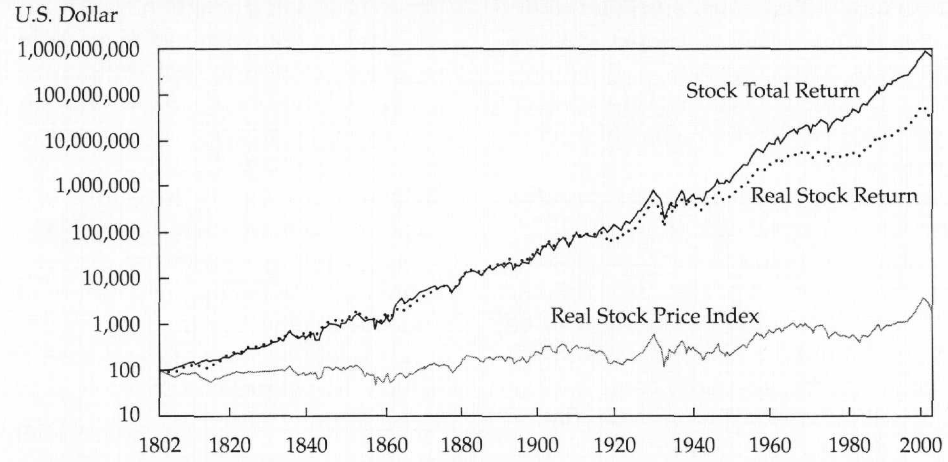
What Expectations Were Realistic in the Past?

To gauge what risk premium an investor might have objectively expected in the longer run past, we need to (1) estimate the real return that investors might reasonably have expected from stocks, (2) estimate the real return that investors might reasonably have expected from bonds, and (3) take the difference. From this exercise, we can gauge what risk premium an investor might reasonably have expected at any point in history, not simply an isolated snapshot of early 1926. A brief review of the sources of stock returns over the past two centuries should help lay a foundation for our work on return expectations and shatter a few widespread misconceptions in the process. The sources of the data are given in Appendix A.[11]

Step I: How Well Does Economic Growth Flow into Dividend Growth? Over the past 131 years, since reliable earnings data became available in 1870, the average earnings yield has been 7.6 percent and the average real return for stocks has been 7.2 percent; this close match has persuaded many observers to the view (which is wholly consistent with finance theory) that the best estimate for real returns is, quite simply, the earnings yield. On careful examination, this hypothesis turns out to be wrong. In the absence of changing valuation levels, real returns are systematically *lower* than earnings yields.

Figure 1 shows stock market returns since 1802 in a fashion somewhat different from that shown in most of the literature. The solid line in Figure 1 shows the familiar cumulative total return for U.S. equities since 1802, in which each $100 invested grows, with reinvestment of dividends, to almost $700 million in 200 years. To be sure, some of this growth came from inflation; as the line "Real Stock Return" shows, $700 million will not buy what it

Figure 1. Return from Inflation and Dividends: Growth of $100, 1801–2001

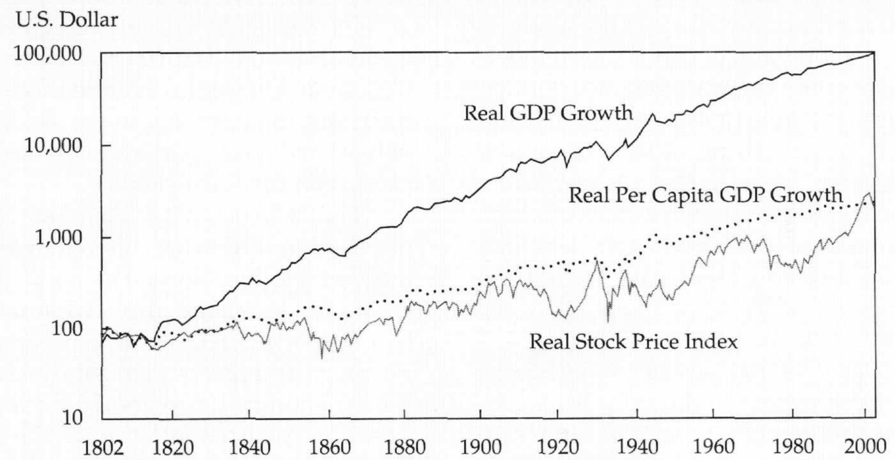


would have in 1802, when one could have purchased the entire U.S. GNP for less than that sum.[12] By removing inflation, we show in the "Real Stock Return" line that the $100 investment grew to "only" $37 million. Thus, adjusted for inflation, our fortune is much diminished but still impressive. Few portfolios are constructed without some plans for future spending, and the dividends that stocks pay are often spent. So, the "Real Stock Price Index" line shows the wealth accumulation from price appreciation alone, net of inflation and dividends. This bottom line (literally and figuratively) reveals that stocks have risen just 20-fold from 1802 levels. Put another way, if an investor had placed $100 in stocks in 1802 and received and spent the average dividend yield of 4.9 percent for the next 200 years, his or her descendants would today have a portfolio worth $2,099, net of inflation. So much for our $700 million portfolio!

Worse, the lion's share of the growth from $100 to $2,099 occurred in the massive bull market from 1982 to date. In the 180 years from 1802 to the start of 1982, the real value of the $100 portfolio had grown to a mere $400. If stocks were priced today at the same dividend yields as they were in 1802 and 1982, a yield of 5.4 percent, the $100 portfolio would be worth today, net of inflation and dividends, just $550. These data put the lie to the conventional view that equities derive most of their returns from capital appreciation, that income is far less important, if not irrelevant.

Figure 2 allows a closer look at the link between equity price appreciation and economic growth. It shows that the growth in share prices is much more closely tied to the growth in real *per capita* GDP (or GNP) than to growth in real GDP per se. The solid line shows that, compounding at about 4 percent in the 1800s and 3 percent in the 1900s, the economy itself delivered an impressive 1,000-fold growth.

Figure 2. The Link between Stock Prices and Economic Growth, 1802–2001



But net of inflation and dividend distributions, stock prices (the same "Real Stock Price Index" line in Figure 1) fell far behind, with cumulative real price appreciation barely 1/50 as large as the real growth in the economy itself.

How can this be? Can't shareholders expect to participate in the growth of the economy? No. Shareholders can expect to participate *only in the growth of the enterprises they are investing in.* An important engine for economic growth is the creation of new enterprises. The investor in today's enterprises does not own tomorrow's new enterprises—not without making a separate investment in those new enterprises with new investment capital.

Finally, the "Real Per Capita GDP Growth" line in Figure 2 shows the growth of the economy measured net of inflation *and population growth.* This growth in real per capita GDP tracks much more closely with the real price appreciation of stocks (the bottom line) than does real GDP itself.

Going one step further, **Figure 3** shows the internal growth of real dividends—that is, the growth that an index fund would expect to see in its own real dividends in the absence of additional investments, such as reinvestment of dividends.[13] Real dividends exhibit *internal* growth that is similar to the growth in real per capita GDP. Because growth in per capita GDP is a measure of productivity growth, the internal growth that can be sustained in a diversified market portfolio should closely match the growth of *productivity* in the economy, not the growth in the economy per se. Therefore, the dotted line traces per capita real GDP growth, the "Real Stock Price Index" line shows real stock prices, and the bottom line shows real dividends (× 10).[14] Figure 3 reveals the remarkable resemblance between real dividend growth and growth in real per capita GDP.

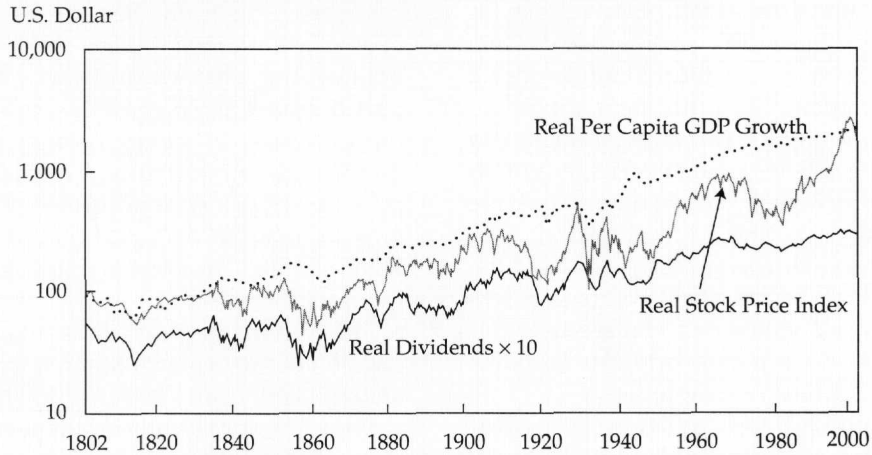
When we measure the internal growth of real dividends as in Figure 3, we see that real dividends have risen a modest fivefold from 1802 levels. In other words, the real dividends for a $100 portfolio invested in 1802 have grown merely 0.9 percent a year net of inflation. To be sure, the price assigned to each dollar of dividends has quadrupled, which leads to the 20-fold real price gain in the 200 years.

Although real dividends have tracked remarkably well with real per capita GDP, they have consistently fallen short of GDP gains. Not only have real dividends failed to match real GDP growth (as many equity investors seem to think is a *minimal* future growth rate for earnings and dividends), they have even had a modest shortfall, at an average of about 70 bps a year, relative to per capita economic growth.

In short, more than 85 percent of the return on stocks over the past 200 years has come from (1) inflation, (2) the dividends that stocks have paid, and (3) the rising valuation levels (rising P/Es and falling dividend yields) since 1982, not from growth in the underlying fundamentals of real dividends or earnings.[15] Furthermore, real dividends and real per capita GDP both grew faster in the 20th century than in the 19th century. Conversely, GDP grew faster in the 19th century than in the 20th century, *unless* we convert to per capita GDP.

Many observers think that earnings growth is far more important than dividend growth. We respectfully disagree. As noted by Hicks (1946), ". . . any increase in the present value of prospective net receipts must raise profits." In other words, properly stated, earnings should represent a proportional share of the net present value of all future

Figure 3. Dividends and Economic Growth, 1802–2001



profits. The problem is that reported earnings often do not follow this theoretical definition. For example, negative earnings should almost never be reported, yet reported operating losses are not uncommon. Furthermore, the quality of earnings reports prior to the advent of the U.S. SEC is doubtful at best; worse, we were unable to find any good source for earnings information prior to 1870. Accordingly, the dividend is the one reliable aspect of stock ownership over the past two centuries. It is the cash income returned to the shareholders; it is the means by which the long-term investor earns most of his or her internal rate of return. Finally, with earnings growth barely 0.3 percent faster than dividend growth over the past 131 years, an analysis based on earnings would reach conclusions nearly identical to our conclusions based on dividends.

Finance theory tells us that capital is fungible; that is, equity and debt, retained earnings and dividends—all should flow to the best use of capital and should (in the absence of tax-related arbitrages and other nonsystematic disruptions) produce a similar risk-adjusted return on capital. Thus, the retained earnings should deliver a return similar to the return an investor could have earned on that capital had it been paid out as dividends. Consider an example: If a company has an earnings yield of 5 percent (corresponding to a P/E of 20), it can pay out all of the earnings and thereby deliver a 5 percent yield to the shareholder. The real value of the company should not be affected by this full earnings distribution (unless the earnings are themselves being misstated), so the 5 percent earnings yield should also be the expected real return. Now, if the company, instead, pays a 2 percent yield and retains earnings worth 3 percent of the stock price, the company ought to achieve 3 percent real growth in earnings; otherwise, it should have distributed the cash to the shareholders. How does this theory stand up to reality?

Over the past 200 years, dividend yields have averaged 4.9 percent, yet real returns have been far higher, 6.6 percent. Since 1870, earnings yields have averaged 7.6 percent, close to the real returns of 7.2 percent over that span. This outcome is consistent with the notion of fungible capital, that the return on capital reinvested in an enterprise ought to match the return an investor might otherwise have earned on that same capital if it had been distributed as a dividend. However, if we take out the changes in valuation levels since 1982 (regardless of whether dividend yields or P/Es are used for those levels), the close match between earnings yield and real stock returns evaporates.

Moreover, with an average earnings yield of 7.6 percent and an average dividend yield of 4.7 percent since 1871, the average "retained earnings yield" has been nearly 3 percent. This retained earnings yield should have led to real earnings and dividend growth of 3 percent; otherwise, management ought to have paid this money out to the shareholders. Instead, real dividends and earnings grew at annual rates of, respectively, 1.2 percent and 1.5 percent. Where did the money go? The answer is that during the era of "pirate capitalism," success often led to dilution: Company managers issued themselves more stock![16]

Furthermore, retained earnings often chase poor internal reinvestment opportunities. If existing enterprises experienced only 1.2–1.5 percent internal growth of real dividends and earnings in the past two centuries, most of the 3.6 percent economic growth the United States has enjoyed has clearly not come from reinvestment in existing enterprises. In fact, it has stemmed from entrepreneurial capitalism, from the creation of new enterprises. Indeed, dividends on existing enterprises have fallen relative to GDP growth by approximately 100-fold in the past 200 years.[17]

The derring-do of the pirate capitalists of the 19th and early 20th centuries is not the only or even the most compelling explanation for this phenomenon. All the data we used are from indexes, which are a particular kind of sampling of the market. Old companies fading from view lose their market weight as the newer and faster growing companies gain a meaningful share in the economy. The older enterprises often have the highest earnings yield and the worst internal reinvestment opportunities, but the new companies do not materialize in the indexes the minute they start doing business or even the minute they go public. When they do enter the index, their starting weight is often small.

Furthermore, an index need only change the divisor whenever a new enterprise is added, whereas we cannot add a new enterprise to our portfolio without cost. The index changing the divisor is mathematically the same as selling a little bit of *all other* holdings to fund the purchase of a new holding, but when we add a new enterprise to our portfolios, we must commit some capital to effect the purchase. Whether through reinvestment of dividends or infusion of new capital, this new enterprise cannot enter our portfolio through the *internal* growth of an existing portfolio of assets. In effect, we must rebalance out of existing stocks to make room for the new stock—which produces the natural dilution that takes place as a consequence of the creation of new enterprises in a world of entrepreneurial capitalism: The same dollar cannot own an existing enterprise and simultaneously fund a new enterprise.[18]

The dynamics of the capitalist system inevitably lead to these kinds of results. Good business leads to expansion; in a competitive environment, expansion takes place on a wide scale; expansion on a wide scale intensifies the competitive environment; margins begin to decline; earnings growth slows; in time, earnings begin to decline; then, expansion slows, profit margins improve, and the whole thing repeats itself. We can see this drama playing out in the relationship between payout ratios in any given year and earnings growth: Since 1984, the payout ratio has explained more than half of the variation in five-year earnings growth rates with a t-statistic of 9.51.[19]

Few observers have noticed that much of the difference between stock dividend yields and the real returns on stocks can be traced directly to the upward revaluation of stocks since 1982. The historical data are muddied by this change in valuation levels—which is why we find the current fashion of forecasting the future by extrapolating the past to be so alarming. The earnings yield is a better estimate of future real stock returns than any extrapolation of the past. And the dividend yield plus a small premium for real dividend growth is even better, because in the absence of changes in valuation levels, the earnings yield systematically overstates future real stock returns.

If long-term real growth in dividends had been 0.9 percent, real stock returns would have been only 90 bps higher than the dividend yield if it were not for the enormous jump in the price-to-dividend ratio since 1982. Even if we adjust today's 1.4 percent dividend yield sharply upward to include "dividends by another name" (e.g., stock repurchases), making a case for real returns higher than the 3.4 percent currently available in the TIPS market would be a stretch.[20]

Step II: Estimating Real Stock Returns. To estimate the historical equity risk premium, we must compare (1) a realistic estimate of the *expected* real stock return that objective analysis might have supported in past years with (2) the *expected* real bond return available at the time. Future long-term real stock return is defined as[21]

$$RSR(t) = DY(t) + RDG(t) + \Delta PD(t) + \varepsilon, \quad (1)$$

where

$DY(t)$ = percentage dividend yield for stocks at time t

$RDG(t)$ = percentage real dividend growth rate over the applicable span starting at time t

$\Delta PD(t)$ = percentage change in the price assigned to each dollar of dividends starting at time t

ε = error term for sources of return not captured by the three key constituents (this term will be small because it will reflect only compounding effects)

Viewed from the perspective of forecasting future real returns, the $\Delta PD(t)$ term is a valuation term, which we deliberately exclude from our analysis. If markets exhibit reversion to the mean, valuation change should be positive when the market is inexpensive and negative when the market is richly priced. If markets are efficient, this term should be random. We choose not to go down the slippery slope of arguing valuation, even though we believe that valuation matters. Rather, we prefer to make the simplifying assumption that market valuations at any stage are "fair" and, therefore, that the real return stems solely from the dividend yield and real growth of dividends.

That said, the estimation process becomes more complex when we consider a sensible estimate for real dividend growth. For example, what real dividend growth rate might an investor in 1814 have expected on the heels of the terrible 1802–14 bear market and depression, during which real per capita GDP, real dividends, and real stock prices all contracted 40–50 percent? How can we objectively put ourselves in the position of an investor almost 200 years ago? For this purpose, we partition the real growth in dividends into two constituent parts, real economic growth and the growth of dividends relative to the economy.

Why not simply forecast dividend growth directly? Because countless studies have shown that analysts' forecasts are too optimistic, especially at market turning points. In fact, dividends (and earnings) in aggregate cannot grow as fast as the economy on a sustainable long-term basis, in large part because of the secular increase in shares outstanding and introduction of new enterprises. So, long-term dividend growth should be equal to long-term economic growth minus a haircut for dilution or entrepreneurial capitalism (the share of economic growth that is tied to new enterprises not yet available in the stock market) or plus a premium for hidden dividends, such as stock buybacks. So, real dividend growth is given by

$$RDG(t) = RGDP(t) + DGR(t) + \varepsilon, \quad (2)$$

where

$RGDP(t)$ = percentage real per capita GDP growth over the applicable span starting at time t

$DGR(t)$ = annual percentage dilution of real GDP growth as it flows through to real dividends starting at time t

ε = error term for compounding effects (it will be small)

Basically, in Equation 2, we are substituting $RGDP(t) + DGR(t)$ for $RDG(t)$ and rolling the $\Delta PD(t)$ term into the error term (to avoid getting into the debates about valuation and regression to the mean). With these two changes, and converting to an expectations model, our model for expected real stock market returns, *ERSR*, becomes

$$ERSR(t) = EDY(t) + ERGDP(t) + EDGR(t), \tag{3}$$

where

$EDY(t)$ = *expected* percentage dividend yield for stocks at time t

$ERGDP(t)$ = *expected* percentage real per capita GDP growth over the applicable span starting at time t

$EDGR(t)$ = *expected* annual percentage dilution of real per capita GDP growth as it flows through to real dividends starting at time t

A complication in this structure is the impact of recessions. In serious recessions, dividends are cut and GDP growth stops or reverses, possibly leading to a decline in even the long-term GDP growth. The result is a dividend yield that is artificially depressed, real per capita GDP growth that is artificially depressed, and long-term dividend growth relative to GDP growth that is artificially depressed, all three of which lead, in recessionary troughs, to understated expected real stock returns. The simplest way to deal with this issue is to use the last peak in dividends before a business downturn and the last peak in GDP before a business downturn in computing each of the three constituents of expected real stock returns.[22]

We illustrate how we constructed an objective real stock return forecast for the past 192 years in **Figure 4**; Panel A spans 1810 to 2001, and Panel B shows the same data after 1945. To explain these graphs, we will go through them line by line.

The easiest part of forecasting real stock returns, the "Estimated Real Stock Return" line in Figure 4, is the dividend yield: It is a known fact. We have adjusted dividends to correct for the artificially depressed dividends during recessions to get the $EDY(t)$ term shown as the "Dividend Yield" line in Figure 4. This step allows us to avoid understating the equity risk premium in recessions when dividends are artificially depressed. This adjustment boosts the expected dividend yield slightly relative to the raw dividend yield because the deepest recessions are often deeper than the average recessions of the prior 40 years. Against an average dividend yield of 4.9 percent, we found an average *expected* dividend yield of 5.0 percent.

Most long-run forecasts of earnings or dividend growth ignore the simple fact that aggregate earnings and dividends in the economy cannot sustainably grow faster than the economy itself. If new enterprise creation and secondary equity offerings dilute the share of the economy held by the shareholders in existing enterprises, then one sensible way to forecast dividend growth is to forecast economic growth and then forecast how rapidly this dilution will take place.[23] Stated another way, we want to know how much *less* rapidly dividends (and earnings) on existing enterprises can grow than the economy at large. The sum of real economic growth less this shortfall is the real growth in dividends.

The resulting line, "Dilution of GDP Growth in Dividends," in the two graphs of Figure 4 represents the $EDGR(t)$ term in our model (Equation 3). Note the persistent tendency for dividend growth to lag GDP growth: Real dividends have grown at 1 percent a year over the past 192 years, whereas the real economy has grown at 3.8 percent a year, and even real per capita GDP has grown at 1.8 percent a year. Why should real dividends have grown so much more slowly than the economy?

First, much of the growth in the economy has come from innovation and entrepreneurial capitalism. More than half of the capitalization of the Russell 3000 today consists of enterprises that did not exist 30 years ago. The 1971 buy-and-hold investor could not participate in this aspect of GDP growth or market growth because the companies did not exist. So, today's dividends and earnings on the existing companies from 1971 are only part of the dividends and earnings on today's total market.

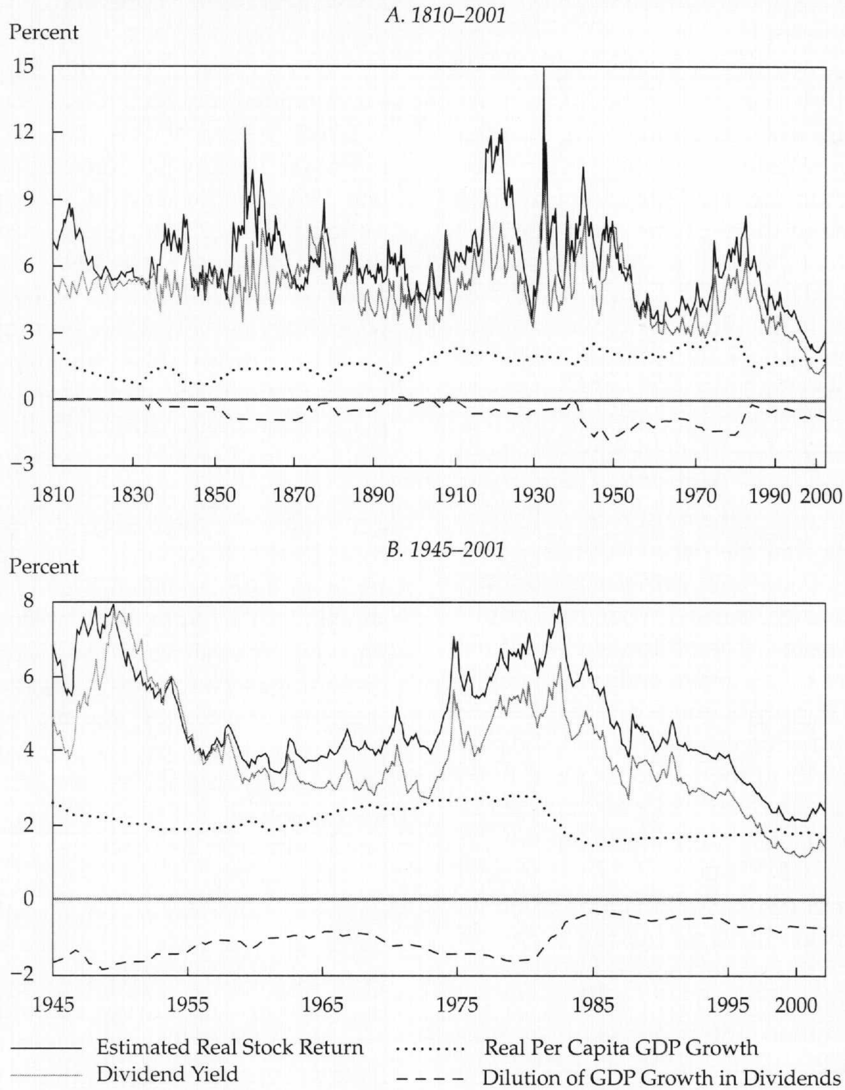
Second, as was demonstrated in Bernstein (2001b), retained earnings are often not reinvested at a return that rivals externally available investments; earnings and dividend growth are faster when payout ratios are high than when they are low, perhaps because corporate managers are then forced to be more selective about reinvestment alternatives.[24]

Finally, as we have emphasized, corporate growth typically leads to more shares outstanding, which automatically imposes a drag on the growth in dividends per share.

As a sensible estimate of the future dividend/GDP shortfall, the rational investor of any day might forecast dividend growth by using the prior 40-year shortfall in dividend growth relative to per capita GDP or might choose to use the cumulative (by now, 200-year) history. We chose the simple expedient of averaging the two.

The dilution effect we found from the 40-year and cumulative data for real dividends and real per capita GDP averages –60 bps. So, in the past 40 years, the dilution of dividend growth is almost

Figure 4. Estimating Real Stock Returns



exactly the same as the long-term average, –80 bps. With a standard deviation of just 0.5 percent, this shortfall of dividend growth relative to economic growth is the steadiest of any of the components of real stock returns or real bond returns. It has never been materially positive on a long-term sustained basis; it has never risen above +10 bps for any 40-year span in the entire history since 1810.

The history of dividend growth shows no evidence that dividends can ever grow materially faster than per capita GDP. Indeed, they almost always grow more slowly. Suppose real GDP growth in the next 40 years is 3 percent a year and population growth is 1 percent a year. These assumptions would appear to put an *upper limit* on real dividend growth at a modest 2 percent a year, far below consensus expectations. If the historical average dilution of dividend growth relative to real per capita GDP growth prevails, then the future real growth in dividends should be only about 1 percent, even with relatively robust, 2.5–3.0 percent, real GDP growth.

Now consider the third part of forecasting real stock returns in this fashion—the forecast of long-term real per capita GDP growth, *ERGDP*(*t*) in our model. How much real per capita GDP growth would an investor have expected at any time in the past 200 years? Again, a simple answer might come from the most recent 40 years' growth rate; another might come from the cumulative record going back as far as we have dividend and GDP data, to 1802. These historical data are shown in the "Real per Capita GDP Growth" line in Figure 4. And again, we chose the simple expedient of averaging the average of the two. Real per capita GDP growth has been remarkably stable over the past 200 years, particularly if we adjust it to correct for temporary dips during recessions. If we examine truly long-term results, the 40-year real growth rate in real per capita GDP has averaged 1.8 percent with a standard deviation of only 0.9 percent.[25]

Note from Figure 4 that the total economy grew faster during the 19th century than the 20th century whereas stock returns (and the underlying earnings and dividends) grew faster in the 20th century than the 19th. Why would the rapid growth of the 19th century flow through to the shareholder less than the slower growth of the 20th century? We see two possible answers. First, the base from which industrial growth started in the 19th century was so much smaller that much faster new enterprise creation occurred then than in the 20th century. Second, with nearly 3 percent growth in the population from 1800 to 1850, the growing talent and labor pool fueled a faster rate of growth than the 1.25 percent annual population growth rate of the most recent 50 years. It is not surprising that the pace of dilution, both from the creation of new enterprises and from secondary equity offerings, is faster when the population is growing faster. Population growth fuels growth in human capital, in available labor, and in both demand *and* supply of goods and services. As a result, when population growth is rapid, the pace of dilution of growth in the economy (as it flows through to a shareholder's earnings and dividends) is far more stable relative to real per capita GDP than relative to real GDP itself.

The simple framework we have presented for estimating real stock returns reveals few surprises. As Panels A and B of Figure 4 show, the expected stock return is the sum of the three constituent parts graphed in the other lines. We estimate that expected real stock returns for the past 192 years averaged about 6.1 percent with the following constituent parts: an expected yield averaging 5.0 percent plus real per capita GDP growth of 1.7 percent a year minus an expected *shrinkage* in dividends relative to real per capita GDP averaging –0.6 percent. Meanwhile, investors actually earned real returns of 6.8 percent. Most of this 70 bp difference from the 6.1 percent rational expectation over the past 192 years can be traced to the rise in valuation levels since 1982; the rest consists of the other happy accidents detailed previously.

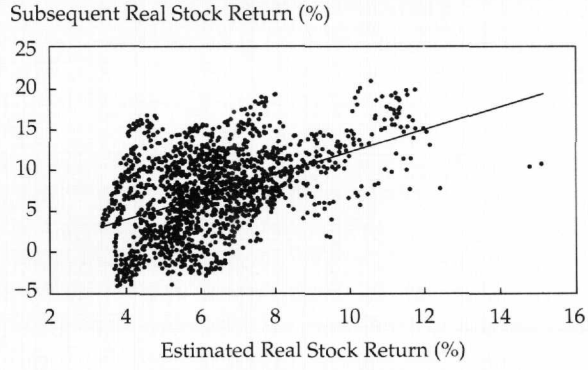
Expectations for real stock returns have soared above 6 percent often enough that many actuaries even today consider 8 percent a "normal" real return for equities. Our estimate for real stock returns, however, exceeds 8 percent only during the depths of the Great Depression, in the rebuilding following the War of 1812, the Civil War, World War I, and World War II, and in the Crash of 1877. In the past 50 years, expected real stock returns above 7 percent have been seen only in the aftermath of World War II, when many investors still feared a return to Depression conditions, and in the depths of the 1982 bear market.

When viewed from the vantage point of this formulation for expected real stock returns, the full 192-year record shows that expected real stock returns fell below 3.5 percent only once before the late 1990s, at the end of 1961 just ahead of the difficult 1962–82 span, real stock prices fell by more than 50 percent. Since 1997, expected real stock returns have fallen well below the 1961 levels, where they remain at this writing.

This formulation for expected real stock returns reveals the stark paradigm shift that took place in the 1950s. Until then, the best estimate for real dividend growth was rarely more than 1 percent, so the best estimate for real stock returns was approximately the dividend yield plus 100 bps—considerably less than the earnings yield! From the 1950s to date, as Panel B of Figure 4 shows, the shortfall of dividends relative to GDP growth improved (perhaps because the presence of the SEC discourages company managers from ignoring shareholder interests) and the real return that one could objectively expect from stocks finally and persuasively rose above the dividend yield. Today, it stands at almost twice the dividend yield, but it is still a modest 2.4 percent.

Figure 5 shows the strong correlation between our formulation for expected real stock returns and the actual real returns that stocks have delivered over the subsequent 10-year span. The correlation is good—at 0.62 during the modern market era after World War II and 0.46 for the full 182 years.[26] If we test the correlation between this simple metric of expected real stock returns and the actual subsequent 20-year real stock returns (not shown), the correlations grow to 0.95 and 0.60 for the post-1945 period and the full 182 years, respectively.

Figure 5. Estimated and Subsequent Actual Real Stock Returns, 1802–2001



The regression results given in Panel A **Table 1** show that the coefficient in the regression is larger than 1.00. So, that 100 bp increase in the expected real stock return, *ERSR*, is worth more than 100 bps in the subsequent 10-year actual real stock return, *RSR*. The implication is that some tendency for reversion to the mean does exist and that it will magnify the effect of unusually high or low expected real stock returns. This suggestion has worrisome implications for the recent record low levels for expected real stock returns.

Because rolling 10-year returns (and expected returns in our model) are highly serially correlated, the *t*-statistics given in Panel A of Table 1 are not particularly meaningful. One way to deal with overlapping data is to eliminate the overlap by using nonoverlapping samples—in this case, examining only our 19 nonoverlapping samples beginning December 1810. The Panel B results, with a coefficient larger than 1.00, confirm the previous results (and approach statistical significance, even with only 17 degrees of freedom).[27] One worrisome fact, in light of the recent large real stock returns, is that the nonoverlapping real stock returns by decades have a –31 percent serial correlation. Although it is not a statistically significant correlation, it is large enough to be interesting: It suggests that spectacular decades or wretched decades may be considerably more likely to reverse than to repeat.

Evaluating the real returns on stocks is clearly a useful exercise if the metric of success for a model is subsequent actual real returns, but we live in a relative world. The future real returns on all assets will rise and fall; so, real returns are an insufficient metric of success. What is of greater import is whether this metric of prospective real stock returns helps us identify the attractiveness of stocks *relative to other assets.*

Step III: Estimating Future Real Bond Returns. On the bond side, real realized returns are equal to the nominal yield minus inflation (or plus deflation) and plus or minus yield change times duration:

$$RBR(t) = BY(t) - INFL(t) + \Delta BY(t)DUR(t) + \varepsilon, \quad (4)$$

where

$BY(t)$ = percentage bond yield at time t

$INFL(t)$ = percentage inflation over the applicable span starting at time t

$\Delta BY(t)DUR(t)$ = annual change in yield over the applicable span times duration at time t (under the assumption that rolling reinvestment is in bonds of similar duration)

ε = error term (compounding effects lead to a small error term in this simple formulation)

As with stocks, we prefer to take current yields as a fair estimate of future bond yields. So, we eliminate the variable that focuses on changes in yields, $\Delta BY(t)DUR(t)$. We also need to shift our focus from measuring past real bond returns to forecasting future real bond returns. Therefore, our model is

$$ERBR(t) = BY(t) - EINFL(t), \quad (5)$$

where $BY(t)$ is the percentage bond yield at time t and $EINFL(t)$ is the expected percentage inflation over the applicable span starting at time t.

Equation 5 is difficult only in the sense that expectations for inflation in past economic environs are difficult to estimate objectively. How, for example, are we to gauge how much inflation an investor in February 1864 would have expected at a time when inflation had averaged 20 percent over the prior three years because of wartime shortages?

Table 1. Regression Results: Estimated Real Stock Return versus Actual 10-Year Real Stock Return
(*t*-statistics in parentheses)

Period	*a*	*b*	R^2	Correlation	Serial Correlation
A. Raw data: RSR(t) = a + b[ERSR(t – 120)]					
1810–2001	–1.51%	1.38%	0.214	0.46	0.992
	(–4.2)	(24.4)			0.990
1945–2001	–7.80	3.15	0.391	0.62	0.996
	(–8.8)	(19.0)			0.995
B. Using 19 nonoverlapping samples, beginning December 1810					
1810–2000	–0.35%	1.22%	0.182	0.430	–0.315
	(–0.1)	(1.9)			0.021

Expectations would depend strongly on the outcome of the war: A victory by the North would have been expected to result in a restoration of the purchasing power of the dollar as wartime shortages disappeared; a victory by the South could have had severe consequences on the ultimate purchasing power of the North's dollar as a consequence of debt that could no longer be serviced. A rational expectation might have been for inflation greater than 0 (reflecting the possibility of victory by the South) but less than the 20 percent three-year inflation rate (reflecting the probability of victory by the North).

We based the estimate for expected future inflation on an *ex ante* regression forecast of 10-year future inflation based, in turn, on recent three-year inflation.[28] **Figure 6** shows how the expected rate of inflation has steadily become more closely tied to recent actual inflation in recent decades. Bond yields responded weakly to bursts of inflation up until the time of the Great Depression; they responded more strongly as inflation became a structural component of the economy in the past four decades.

Until the last 40 years, inflation was generally associated with wars and was virtually nonexistent—even negative—in peacetime. Figure 6 shows a burst of double-digit inflation on the heels of the War of 1812, in the late stages of the Civil War, during World War I, and in the rebuilding following World War II. And more recently, double-digit inflation characterized the "stagflation" of 1978–1981 that followed the Vietnam War and the oil shocks of the 1970s. The most notable changes since the Great Depression, especially since World War II, involve the magnitude and perceived role of government and loss of the automatic brakes once applied by the gold standard. From the end of World War II to the great inflationary crisis at the end of the 1970s, the dread of unemployment that was inherited from the Great Depression was the driving factor in both fiscal and monetary policy.

With the introduction of TIPS in January 1997, we finally have a U.S. government bond that pays a real return, which allows us to simplify the expected real bond returns to be the TIPS yield itself from that date forward; that is,

$$ERBR(t) = YTIPS(t), \qquad (6)$$

where $YTIPS(t)$ is the percentage TIPS yield at time t.

Figure 7 shows how the current government bond yield (the "Bond Yield" line) minus expected inflation ("Estimated Inflation") leads to an estimate of the real bond return and hence the long-term expected real bond return ("Estimated Real Bond Yield"), which is the estimate through March of 1998 and the TIPS yield thereafter.[29] From the Equation 5 (or, more recently, Equation 6) formulation, expected real bond returns averaged 3.7 percent over the full period, a very respectable real yield, given the limited risk of government bonds, and good recompense for an investor's willingness to bear some bond-price volatility. Investors may not always have viewed government debt as the rock-solid investment, however, that it is generally considered today.

The 3.7 percent real bond return consists of an average nominal bond yield of 4.9 percent minus an expected inflation rate of 1.2 percent. For comparison, the average actual inflation rate has been 1.4 percent. In the years after World War II, the rate of peacetime inflation embedded in investors' memory banks was essentially zero, perhaps even slightly negative. Consequently, bond investors kept expecting inflation to go away, despite its persistence at a modest rate in the 1950s and early 1960s and an accelerating rate thereafter. As a result, bonds were badly priced for reality during most of

Figure 6. Estimating Future Inflation, 1810–2001

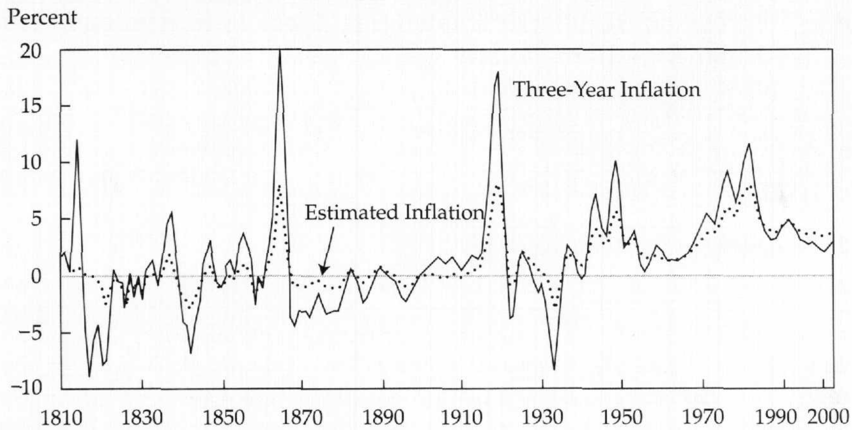
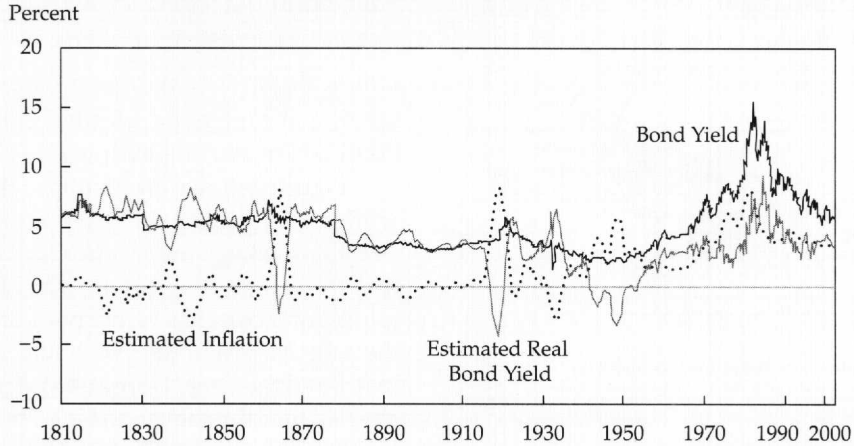


Figure 7. Estimating Real Bond Yields, 1810–2001



these two decades; they turned out to be certificates of confiscation for their holders until people finally woke up in the 1970s and 1980s. Actual inflation exceeded expected inflation with few exceptions from the start of World War II until roughly 1982; as can be seen in Figure 7, our model captures this phenomenon. Expectations are lower than actual outcomes during this span.

Figure 7 also shows several regimes of real yield with distinct structural change from one regime to the next. From the time the United States was in its infancy until the end of Reconstruction in the late 1870s, investors would not have viewed U.S. government bonds as a secure investment. They would have priced these bonds to deliver a 5–7 percent real yield, except during times of war. The overall stability of the yields is impressive: Unlike the history of stock prices, the surprise elements have been small.

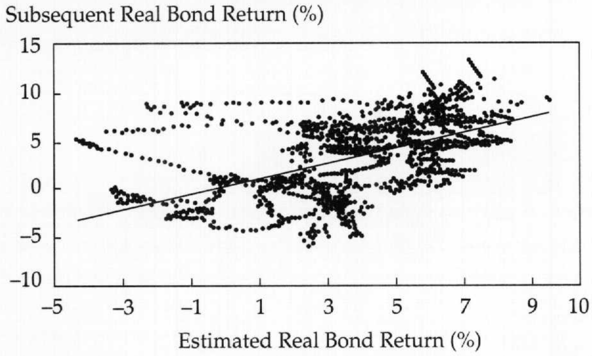
Once the United States had survived the Civil War and the security of U.S. government debt had been demonstrated repeatedly, investors began to price government debt at a 3–5 percent real yield. As Figure 7 shows, this level held, with a brief interruption in World War I, until the country went off the gold standard in 1933. This record is remarkable in view of the high rate of economic growth, but revolutionary technological change in those days, especially in transportation and agriculture, led to such stunning reductions in product costs that inflation was kept at bay except for very brief intervals.

For the next 20–25 years, the nation struggled with the Great Depression, World War II, and the war's aftermath. Investors slowly began to realize that deflationary price drops did not rebound fully after the trough of the Depression and that inflationary price increases did not retreat after the end of the war. The changed role of government plus the end of the gold standard had altered the picture, perhaps irrevocably. During this span, investors priced bonds to offer a 2–4 percent *notional* yield but a rocky −3 percent to +3 percent real yield. As Figure 7 shows, bond investors woke up late to the fact that inflation was now a normal part of life.

From the mid-1950s to date, investors have struggled with more structural inflation and more inflation uncertainty than ever before. Although investors sought to price bonds to deliver a real yield, inflation consistently exceeded their expectations. Only during the down cycle of the inflation roller coaster of 1980–1985 did bonds finally provide real yields to their owners. After this experience, bond investors developed an anxiety about inflation far greater than objective evidence would support. The result was a brief spike in real bond returns in 1984, as Figure 7 shows, with bond yields still hovering at 13.8 percent, even though three-year inflation had fallen to 4.7 percent (and our regression model for future inflation would have suggested expected inflation of 4.6 percent). The "expected" real yield was a most unusual 9.2 percent because investors were not yet prepared to believe that double-digit inflation was a thing of the past.

Another interesting fact is evident in **Figure 8**: The expected real bond returns produced by our formulation are highly correlated with the actual real returns earned over the subsequent decade. For 1810 to 1991, the expected real bond return has a 0.52 correlation with the actual real bond return earned over the next 10 years; from 1945 to date, the correlation rises to an impressive 0.63. Panel A of **Table 2** shows that the coefficient is reliably positive but not reliably more than 1.00, which suggests that, unlike expected real stock returns, no powerful tendency for reversion to the mean is at work in real bond yields. When we used the 19 available nonoverlapping samples (Panel B), we found the resulting correlation to be 0.64, which is a statistically significant relationship.[30]

Figure 8. Estimated and Subsequent Actual Real Bond Yield, 1802–2001



Why is the bond model a better predictor, when raw data are used, than the stock model for the two-century history? Two reasons seem evident. First, stocks have been more volatile than bonds for almost all 200 years of U.S. data. Therefore, any model for expected real stock returns should have a larger error term. Second, stocks are by their very nature longer term than bonds: A 10-year bond expires in 10 years; stocks have no maturity date.

The bond market correlations would be even better were it not for the negative real yields during times of war, when people tend to consider the inflation a temporary phenomenon. These episodes show up as the "loops" to the left of the body of the scatterplot in Figure 8. At these times, many U.S. investors apparently subordinated their own interests in a strong real yield to the needs of the nation: Long Treasury rates were essentially pegged during World War II and up to 1951, but that did not stop investors from buying them.

Step IV: Estimating the Equity Risk Premium. If we now take the difference between the expected real stock return and the expected real bond return, we are left with the expected equity risk premium:

$$ERP(t) = ERSR(t) - ERBR(t), \quad (7)$$

where $ERSR(t)$ is the expected real stock return starting at time t and $ERBR(t)$ is the expected real bond return starting at time t.

Figure 9 shows the results of this simple framework for estimating the risk premium over the past 192 years. Many observers may be startled to see that this estimate of the forward-looking risk premium for stocks has rarely been above 5 percent in the past 200 years; the exceptions are war, its aftermath, and the Great Depression. The historical average risk premium is a modest 2.4 percent, albeit with a rather wide range. The wide range is more a result of the volatility of expected real bond returns than the volatility of expected real stock returns, which are surprisingly steady except in times of crisis.[31]

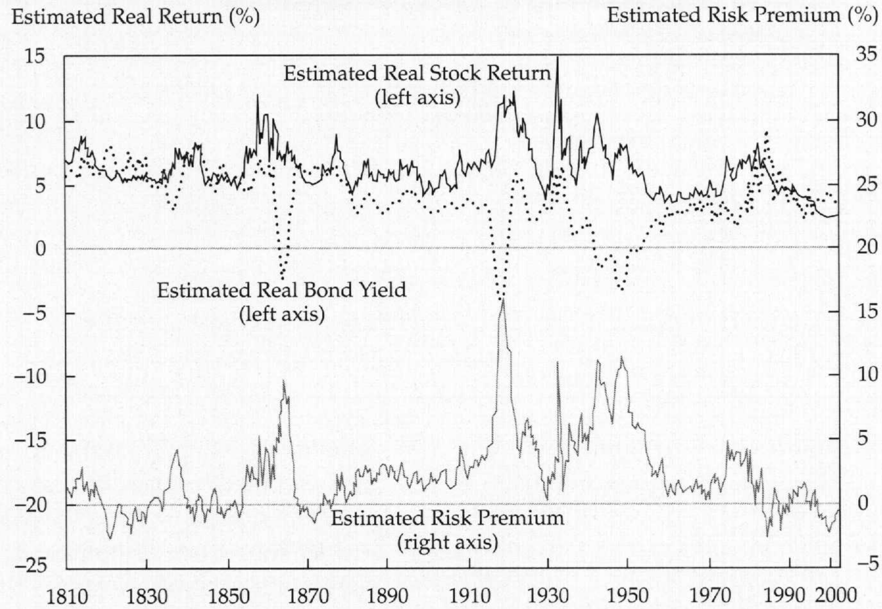
Over the past 192 years, our model (Equation 3) suggests that an objective evaluation would have pegged expected real stock returns at about 6.1 percent on average, only 120 bps higher than the average dividend yield. Investors have earned fully 70 bps more than this objective expectation, but they did not have objective reasons to expect to earn as much as they did. Our model suggests that an objective evaluation would have pegged expected real bond returns at about 3.7 percent. Investors have earned 20 bps less because of the inflationary shocks of the 1960s to 1980s; they expected more than they got.

The difference between the expected real returns for stocks and bonds reveals a stark reality. An objective estimate of the expected risk premium would have averaged 2.4 percent (240 bps) during this history (6.1 percent expected real stock returns minus 3.7 percent expected real bond returns), not the oft-cited 5 percent realized excess return that

Table 2. Regression Results: Estimated Real Bond Return versus Actual 10-Year Real Bond Return
(t-statistics in parentheses)

Period	a	b	R^2	Correlation	Serial Correlation
A. Raw data: $RBR(t) = a + b[ERBR(t - 120)]$					
1810–2001	0.45%	0.81%	0.266	0.52	0.999
	(3.5)	(28.1)			0.997
1945–2001	–0.74	1.05	0.399	0.63	0.997
	(–4.0)	(19.3)			0.980
B. Using 19 nonoverlapping samples, beginning December 1810					
1810–2001	–1.81%	1.31%	0.4120	0.64	0.182
	(–1.1)	(3.5)			0.677

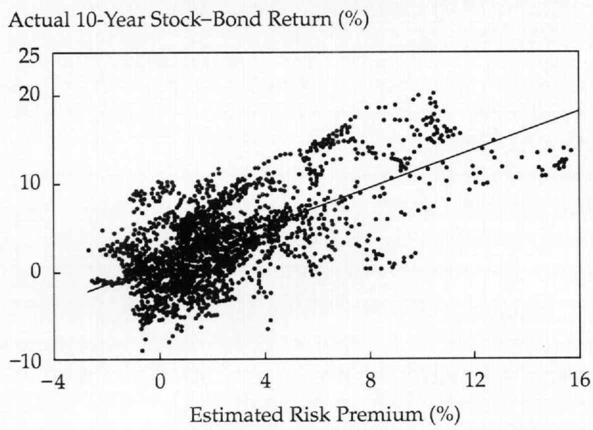
Figure 9. Estimating the Equity Risk Premium, 1810–2001



much of the investment world now depends on. Investors have *earned* a higher 3.3 percent (330 bps) excess return for stocks (6.8 percent actual real stock returns minus 3.5 percent for bonds), but the reason is the array of happy accidents for stocks and one extended unhappy accident for bonds.

All of this analysis is of mere academic interest, however, unless we can establish a link between our estimated risk premium and actual subsequent relative returns. Indeed, such a link does exist. The result of our formulation for the equity risk premium has a 0.79 correlation with the actual 10-year excess return for stocks over bonds since 1945 and a 0.66 correlation for the full span. This strong link is clear in **Figure 10**, for 1810–2001, and **Table 3**

Figure 10. Risk Premium and Subsequent 10-Year Excess Stock Returns: Correlations, 1810–1991



(where, for convenience, we have defined the 10-year excess return of stocks relative to bonds as *ERSB*); each 100 bp change in the equity risk premium is worth modestly more than 100 bps in subsequent annual excess returns for stocks relative to bonds over the next 10 years. As with the expected stock return model (Equation 3), the link for 20-year results is stronger, with correlations over the full span and since 1945 of, respectively, 0.64 and 0.95.

This strong link between objective measures of the risk premium and subsequent stock–bond excess returns is also clear for the 1945–2001 period shown in **Figure 11**, in which every wiggle of our estimate for the risk premium is matched by a similar wiggle in the subsequent 10-year excess return that stockholders earned relative to bondholders. Figure 11 shows that the excess returns on stocks relative to bonds became negative in the late 1960s on a 10-year basis, following low points in the risk premium, and again touched zero 10 years after the 1981 peak in bond yields.

We can also see in Figure 11 how the gap in 10-year results opened up sharply for the 10 years of the 1990s; it opened to unprecedented levels, even wider than in the early 1960s. Prior to this gap opening, the fit between the risk premium and subsequent excess returns is remarkably tight. The question is whether this anomaly is sustainable or is destined to be "corrected." History suggests that such anomalies are typically corrected, especially when the theoretical case to support them is so weak. This reminder should be sobering to investors who are depending on a large equity risk premium.

Table 3. Regression Results: Estimated Equity Risk Premium versus Actual 10-Year Excess Return of Stocks versus Bonds
(*t*-statistics in parentheses)

Period	*a*	*b*	R^2	Correlation	Serial Correlation
A. Raw data: ERSB(t) = a + b[ERP(t – 120)]					
1810–2001	0.91%	1.08%	0.430	0.66	0.993
	(8.8)	(40.6)			0.995
1945–2001	2.85	1.41	0.621	0.79	0.995
	(15.4)	(30.4)			0.996
B. Using 19 nonoverlapping samples, beginning December 1810					
1810–2001	0.84%	1.36%	0.490	0.70	0.055
	(0.8)	(4.0)			0.371

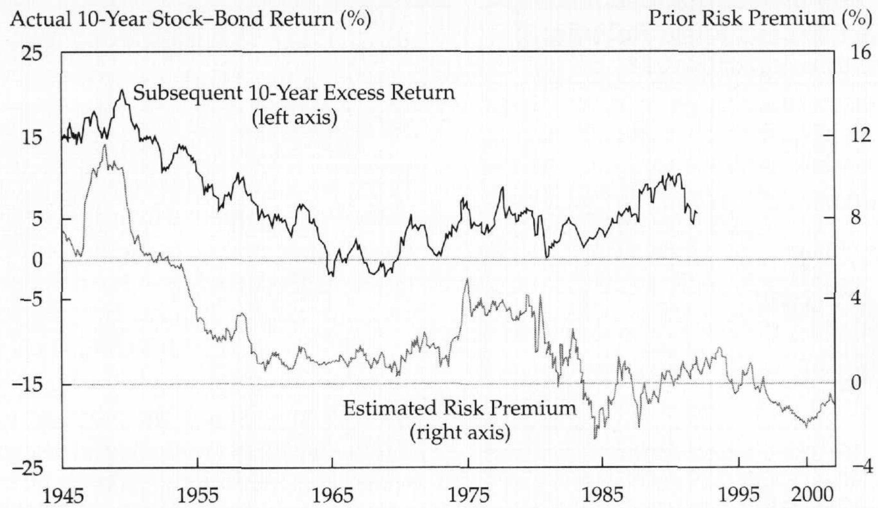
As with the models for real stock returns and for real bond returns, we also used nonoverlapping spans to take out the effect of the strong serial correlation in the estimated risk premium. For the 19 nonoverlapping spans (Panel B of Table 3), the correlation for the full period jumps to 0.70, with a highly significant *t*-statistic of 4.0.[32]

Conclusions

We have advanced several provocative assertions.

- The observed real stock returns and the excess return for stocks relative to bonds in the past 75 years have been extraordinary, largely as a result of important nonrecurring developments.
- It is dangerous to shape future expectations based on extrapolating these lofty historical returns. In so doing, an investor is tacitly assuming that valuation levels that have doubled, tripled, and quadrupled relative to underlying earnings and dividends can be expected to do so again.
- The investors of 75 years ago would not have had an objective basis for expecting the 8 percent real returns or 5 percent risk premium that stocks subsequently delivered. The estimated equity risk premium at the time was above average, however, which makes 1926 a better-than-average starting point for the historical risk premium.
- The real internal growth that companies generated in their dividends averaged 0.9 percent a year over the past 200 years, whereas earnings growth averaged 1.4 percent a year over the past 131 years.
- Dividends and earnings growth was slower than the increase in real per capita GDP, which averaged 1.6 percent over the past 200 years and 2.0 percent over the past 131 years. This internal growth is far less than the consensus expectations for future earnings and dividend growth.

Figure 11. Risk Premium and Subsequent 10-Year Excess Returns, 1945–2001



- The historical average equity risk premium, measured relative to 10-year government bonds as the risk premium investors might objectively have expected on their equity investments, is about 2.4 percent, half what most investors believe.
- The "normal" risk premium might well be a notch lower than 2.4 percent because the 2.4 percent objective expectation preceded *actual* excess returns for stocks relative to bonds that were nearly 100 bps higher, at 3.3 percent a year.
- The current risk premium is approximately zero, and a sensible expectation for the future real return for both stocks and bonds is 2–4 percent, far lower than the actuarial assumptions on which most investors are basing their planning and spending.[33]
- On the hopeful side, because the "normal" level of the risk premium is modest (2.4 percent or quite possibly less), current market valuations need not return to levels that can deliver the 5 percent risk premium (excess return) that the Ibbotson data would suggest. If reversion to the mean occurs, then to restore a 2 percent risk premium, the difference between 2 percent and zero still requires a near halving of stock valuations or a 2 percent drop in real bond yields (or some combination of the two). Either scenario is a less daunting picture than would be required to facilitate a reversion to a 5 percent risk premium.
- Another possibility is that the modest difference between a 2.4 percent normal risk premium and the negative risk premiums that have prevailed in recent quarters permitted the recent bubble. Reversion to the mean might not ever happen, in which case, we should see stocks sputter along delivering bondlike returns, but at a higher risk than bonds, for a long time to come.

The consensus that a normal risk premium is about 5 percent was shaped by deeply rooted naiveté in the investment community, where most participants have a career span reaching no farther back than the monumental 25-year bull market of 1975–1999. This kind of mind-set is a mirror image of the attitudes of the chronically bearish veterans of the 1930s. Today, investors are loathe to recall that the real total returns on stocks were negative for most 10-year spans during the two decades from 1963 to 1983 or that the excess return of stocks relative to long bonds was negative as recently as the 10 years ended August 1993.[34]

When reminded of such experiences, today's investors tend to retreat behind the mantra "things will be different this time." No one can kneel before the notion of the long run and at the same time deny that such circumstances will occur in the decades ahead. Indeed, such crises are more likely than most of us would like to believe. Investors greedy enough or naive enough to expect a 5 percent risk premium and to substantially overweight equities accordingly may well be doomed to deep disappointments in the future as the realized risk premium falls far below this inflated expectation.

What if we are wrong about today's low equity risk premium? Maybe real yields on bonds are lower than they seem. This chance is a frail reed to rely on for support. At this writing, at the end of 2001, an investor can buy TIPS, which provide government-guaranteed yields of about 3.4 percent, but inflation-indexed bond yields are a relatively recent phenomenon in the United States. So, we could not estimate historical real yields for prior years directly, only through a model such as the one described here. If we compare our model for real stock returns, at 2.4 percent in mid-2001, with a TIPS yield of 3.4 percent, we get an estimate for the equity risk premium of –100 bps.

Perhaps real earnings and dividend growth will exceed economic growth in the years ahead, or perhaps economic growth will sharply exceed the historical 1.6 percent real per capita GDP growth rate. These scenarios are certainly possible, but they represent the dreams of the "new paradigm" advocates. The scenarios are unlikely. Even if they prove correct, it will likely be in the context of unprecedented entrepreneurial capitalism, unprecedented new enterprise creation, and hence, unprecedented dilution of shareholders in existing enterprises.

The recurring pattern of history is that exceptionally poor or exceptionally rapid economic growth is never sustained for long. The best performance that dividend growth has ever managed, relative to real per capita GDP, is a scant 10 bp outperformance. This rate, the best 40-year real dividend growth *ever seen,* fell far short of real GDP growth: Real dividend growth was some 2 percent a year below real GDP growth during those same 40-year spans. So, history does not support those who hope that dividend growth will exceed GDP growth. This evidence is not encouraging for those who wish to see a 1.4 percent dividend yield somehow transformed into a 5 percent (or higher) real stock return.

The negative risk premium that precipitated the writing of "The Death of the Risk Premium" (Arnott and Ryan) in early 2000 was not without precedent, although most of the precedents, until recently, are found in the 19th century. In 1984 and again just before the 1987 market crash, real bond yields rose materially above the estimated real return on stocks. How well did this development predict subsequent relative returns? Stated more provocatively, why didn't our model work? Why didn't bonds beat stocks in the past decade? After all, with the 1984 peak in real bond returns and again shortly before the 1987 crash, the risk premium dipped even lower than the levels seen at the market peak in early 2000. Yet, stocks subsequently outpaced bonds. For an answer, recall that the context was a more than doubling of stock valuations, whether measured in price-to-book ratios, price-to-dividend ratios, or P/E multiples. If valuation multiples had held constant, the bonds would have prevailed.[35]

Appendix A. Estimating the Constituents of Return

An analysis of historical data is only as good as the data themselves. Accordingly, we availed ourselves of multiple data sources whenever possible. We were encouraged by the fact that the discrepancies between the various sources led to compounded rates of return that were no more than 0.2 percent different from one another.

Long Government Bond Yields, *BY(t)*. Our data sources are as follows: for January 1800 to May 2001, 10-year government bond yields from Global Financial Data of the National Bureau of Economic Research (NBER) (data were annual until 1843 and were interpolated for monthly estimates); for June 2001 to December 2001, Bloomberg; and for January 1926 to December 2000, Ibbotson Associates, long-term government bond yields and returns. In cases of differences, we (1) averaged the yield data and (2) recomputed monthly total returns based on an assumed 10-year maturity standard.

Inflation, *INF(t)*. We used two sources of inflation and U.S. Consumer Price Index data. For January 1801 to May 2001, NBER (annual until 1950; interpolated for monthly estimates); for June 2001 to December 2001, Bloomberg; and for January 1926 to December 2000, Ibbotson Associates. In cases of differences, we averaged the available data. Ibbotson data were given primary (two-thirds) weighting for 1926–1950 because the NBER data are annual through 1950.

Gross Domestic Product, *GDP(t)*. For January 1800 to September 2001, NBER GNP data annually through 1920, interpolated July-to-July; for 1921–2001, quarterly GDP data; and for December 2001, *Wall Street Journal* consensus estimates.

Dividend Yield in Month *t*, *DY(t)*, and Return on Stocks in Month *t*, *RS(t)*. For January 1802 to December 1925, G. William Schwert (1990); for February 1871 to March 2001, Robert Shiller (2000); for January 1926 to December 2000, Ibbotson Associates (2001); and for April 2001 to December 2001, Bloomberg. In cases of differences, we averaged the available data. In Shiller's data, monthly dividend and earnings data are computed from the S&P four-quarter data for the quarter since 1926, with linear interpolation to monthly figures. Dividend and earnings data before 1926 are from Cowles (1939), interpolated from annual data.

Notes

1. The "bible" for the return assumptions that drive our industry is the work of Ibbotson Associates, building on the pioneering work of Ibbotson and Sinquefield (1976a, 1976b). The most recent update of the annual Ibbotson Associates data (2001) shows returns for U.S. stocks, bonds, bills, and inflation of, respectively, 11.0 percent, 5.3 percent, 3.8 percent, and 3.1 percent. These figures imply a real return for stocks of 7.9 percent and a risk premium over bonds of 5.7 percent (570 bps), both measured over a 75-year span. These data shape the expectations of the actuarial community, much of the consulting community, and many fund sponsors.
2. Fischer Black was fond of pointing out that examining the same history again and again with one new year added each passing year is an insidious form of data mining (see, for example, Black 1976). The past looks best when nonrecurring developments and valuation-level changes have distorted the results; extrapolating the past tacitly implies a belief that these nonrecurring developments can recur and that the changes in valuation levels will continue.
3. We strongly suggest that the investment community draw a distinction between past excess returns (observed returns from the past) and expected risk premiums (expected return differences in the future) to avoid continued confusion and to reduce the dangerous temptation to merely extrapolate past excess returns in shaping expectations for the risk premium. This habit is an important source of confusion that, quite literally, (mis)shapes decisions about the management of trillions in assets worldwide. We propose that the investment community begin applying the label "risk premium" *only* to expected future return differences and apply the label "excess returns" to observed historical return differences.
4. To see the effect of compounding at this rate, consider that if our ancestors could have earned a mere 1.6 percent real return on a $1 investment from the birth of Christ in roughly 4 B.C. to today, we would today have enough to buy more than the entire world economy. Similarly, the island of Manhattan was ostensibly purchased for $24 of goods, approximately the same as an ounce of gold when the dollar was first issued. This modest sum invested to earn a mere 5 percent real return would have grown to more than $20 billion in the 370 years since the transaction. At an 8 percent real return, as stocks earned from 1926 to 2000 in the Ibbotson data, this $24 investment would now suffice to buy more than the entire world economy.

5. No rational investor buys if he or she expects less than 1 percent real growth a year in capital, but objective analysis will demonstrate that this return is what stocks have actually delivered, plus their dividend yield, plus or minus any profits or losses from changes in yields. As Asness pointed out in "Bubble Logic" (2000), few buyers of Cisco would have *expected* a 1 percent internal rate of return at the peak, although the stock was priced to deliver just that, even if the overly optimistic consensus earnings and growth forecasts at the time were used. These buyers were focused on the view that the stock would produce handsome gains, as it had in the past, rather than on pursuing an objective evaluation, by using IRR or similar objective valuation tools, of expected returns. Such a focus plants the seeds of major disappointment.
6. The Welch study investigated an expected *arithmetic* risk premium for stocks relative to *cash*, not bonds. The difference between arithmetic and geometric returns is often illustrated by someone earning 50 percent in one year and –50 percent in the next. The arithmetic average is zero, but the person is down 25 percent (or 13.4 percent a year). Most practitioners think in terms of compounded geometric returns; in this example, practitioners would focus on the 13 percent a year loss, not on the zero arithmetic mean. If stocks have 16 percent average annual volatility (the average since World War II), the result is that the arithmetic mean is 130 bps higher than the geometric mean return (the difference is approximately half the variance, or 16 percent × 16 percent/2). Such a difference might be considered a "penalty for risk." If we add a 70 bp real cash yield (the historical average) plus a 720 bp risk premium minus a 130 bp penalty for risk, we find 6.6 percent to be the implied consensus of the economists for the geometric real stock return.
7. Such a return could easily fall to 0–2 percent net of taxes, especially in light of government's taxes on the inflation component of returns.
8. Smith's work even won a favorable review from John Maynard Keynes (for Keynes' approach, see his 1936 classic).
9. TIPS is the acronym for Treasury Inflation-Protected Securities, which have been replaced by Treasury Inflation-Indexed Securities.
10. In fairness, growth is now an explicit part of the picture. Dividend payout ratios are substantially lower than in the early 1920s and the 19th century as a result, at least in part, of corporate desires to finance growth. That said, our own evidence would suggest that internal reinvestment is not necessarily successful: High payout ratios precede higher growth than do low payout ratios.
11. We are indebted to G. William Schwert and Jeremy Siegel for some of the raw data for this analysis (see also Schwert 1990 and Siegel 1998). Although multiple sources exist for data after 1926 and a handful of sources provide data beginning in 1855 or 1870, Professor Schwert was very helpful in assembling these difficult early data. Professor Siegel provided earnings data back to 1870. We have not found a source for earnings data before 1870.
12. The U.S. Bureau of Labor Statistics maintains GDP data from 1921 to date; the earlier data are for GNP (gross national product). Because the two were essentially the same thing until international commerce became the substantial share of the economy that it is today, we used the GNP data from the Bureau of Labor Statistics for the 19th century and the first 20 years of the 20th century.
13. We stripped out reinvestment in the measure of real dividend growth shown in Figure 3 because investors are already receiving the dividend. To include dividends in the real dividend growth would double-count these dividends. What should be of interest to us is the internal growth in dividends stemming from reinvestment of the retained earnings.
14. We multiplied the real dividends by 10 to bring the line visually closer to the others; the result is that on those few occasions when the price line and dividend line touch, the dividend yield is 10 percent.
15. The fact that growth in real dividends and earnings is closer to per capita GDP growth than it is to overall GDP growth is intuitively appealing on one fundamental basis: Real per capita GDP growth measures the growth in productivity. It is sensible to expect real income, real per share earnings, and real per share dividends to grow with productivity rather than to mirror overall GDP growth.
16. This history holds a cautionary tale with regard to today's stock option practices.
17. This fall in dividends of existing enterprises is not surprising when one considers that the companies that existed in 1802 probably encompass, at most, 1 percent of the economy of 2001. The world has so changed that, at least from the perspective of the dominant stocks, today's economy would be unrecognizable in 1802.
18. Another way to think about this idea is to recognize the distinction between a market portfolio and a market index. The market portfolio shows earnings and dividend growth that are wholly consistent with growth in the overall economy (Bernstein 2001a). But if one were to unitize that market portfolio, the unit values would not grow as fast as the total capitalization and the earnings and dividends per unit (per "share" of the index) would not keep pace with the growth in the aggregate dollar earnings and dividends of the companies that compose the market portfolio. (When one stock is dropped and another added to a market index, typically the added stock is larger in capitalization than the deletion, which increases the divisor for constructing the index.) Precisely the same thing would happen in the management of an actual index fund. When a stock was replaced, the proceeds from the deleted stock would rarely suffice to fund the purchase of the added stock. So, all stocks would be trimmed slightly to fund that purchase; this consequence is implied by the change in the divisor for an index. It is this mechanism that drives the difference between the growth of the aggregate dollar earnings and dividends for the market portfolio, which will keep pace with GDP growth over time, and the growth of the "per share" earnings and dividends for the market *index* that creates the dilution we attribute to entrepreneurial capitalism. After all, entrepreneurial capitalism creates the companies that we must add to the market portfolio, thus changing our divisor and driving a wedge between the growth in market earnings or dividends and the growth in earnings and dividends per share in a market index.
19. See Bernstein (2001b). Over the past 131 years, the correlation between payout ratios and subsequent 10-year growth in real earnings has been 0.39; over the past 50 years, this correlation has soared to 0.66. Apparently, the larger the fraction of earnings paid out as dividends, the faster earnings subsequently grow, which is directly contrary to the Miller–Modigliani maxim (see Miller and Modigliani 1961 and Modigliani and Miller 1958).
20. To produce a 3.4 percent real return from stocks, matching the yield on TIPS, real growth in dividends needs to be 1.9 percent (twice the long-term historical real growth rate) while valuation levels remain where they are. Less than twice the historical growth in real dividends, or a return to the 3–6 percent yields of the past, will not get us there.
21. We have made the simplifying assumption that "long term" is a 10-year horizon. Redefining the long-term returns over a 5-year or 20-year horizon produces similar results.
22. Because this adjusted dividend is always at or above the true dividend, we have introduced a positive error into the average dividend yield. We offset this error by subtracting the 40-year average difference between the adjusted dividend and the true dividend. In this way, $EDY(t)$ is not overstated, on average, over time.

23. Of course, stock buybacks increase the share of the economy held by existing shareholders.
24. Arnott and Asness (2002) have shown that since 1945, the payout ratio has had a 77 percent correlation with subsequent real earnings growth. That is, higher retained earnings have historically led to slower, not faster, earnings growth.
25. Throughout this article, when we refer to a 10-year average or a 40-year average, we have used the available data if fewer years of data were available. For instance, for 1820, we used the 20-year GDP growth rate because 40 years of data were unavailable. We followed a convention of requiring at least 25 percent of the intended data; so, if the analysis was based on a 40-year average, we tolerated a 10-year average if necessary. To do otherwise would have forced us to begin our analysis in about 1840 and lose decades of interesting results. Because data before 1800 are very shaky and we required at least 10 years of data, our analysis begins, for the most part, in 1810.
26. We cannot know the 10-year returns from starting dates after 1991, so 192 years of expected return data lead to 182 years of correlation with subsequent 10-year actual returns.
27. Another way to deal with serially correlated data is to test correlations of differenced data. When we carried out such tests, we found that over the full span, the R^2 actually *rose* to 0.446 from the 0.214 shown in Panel A of Table 1; moreover, since 1945, the differenced results showed a still impressive 46 percent correlation. These results are available from the authors on request.
28. In an *ex ante* regression, the model is respecified for each monthly forecast with the use of all previously available data only.
29. We made the simplifying assumption that "long term" is a 10-year horizon. Redefining the long-term returns over a 5-year or 20-year horizon produced similar results.
30. Even when we considered successive differences to eliminate the huge serial correlation of real bond yields and 10-year real bond returns, the result from 1945 to date (available from the authors) was identical to the result for the raw data—a correlation of 0.63.
31. For investors accustomed to the notion that stock returns are uncertain and bond returns are assured over the life of the bond, this result will come as a surprise. But conventional bonds do *not* assure real returns; their expected real returns, therefore, should be highly uncertain. Stocks do, in a fashion, pass inflation through to the shareholder. So, nominal returns for stocks may be volatile and uncertain, but expected real stock returns are much more tightly defined than expected real bond returns.
32. Differencing caused the correlation for the full 182-year span to fall from 0.66 to 0.61 and, for the span following World War II, caused it to fall from 0.79 to 0.48.
33. For the taxable investor, the picture is worse, of course. In the United States, investors are even taxed on the inflation component of returns. From valuation levels that are well above historical norms, a negative real after-tax return is not at all improbable.
34. The excess return of stocks over bonds was negative also in the decades ended September 1991, November 1990, most 10-year spans ending August 1977 to June 1979, and the spans ending September 1974 to January 1975.
35. Consider the 10 years starting just before the stock market crash in September 1987. This span began with double-digit bond yields. The bond yield of 9.8 percent minus a regression-based inflation expectation of 3.6 percent led to an expected real bond return of 6.2 percent. The stock yield of 2.9 percent plus expected real per capita GDP growth of 1.6 percent minus an expected dividend shortfall relative to per capita GDP of 0.4 percent led to an expected real stock return of 4.0 percent. The risk premium was –2.0 percent. But stocks beat bonds by 4.9 percent a year over the next 10 years ending September 1997. What happened? The dividend yield plunged to 1.7 percent. This plunge in yields contributed 5.8 percent a year to stock returns; in the absence of this revaluation, stocks would have underperformed bonds by –0.9 percent. So, the –2.0 percent forecast was not bad; dividends rose a notch faster than normal, and more importantly, the price that the market was willing to pay for each dollar of dividends nearly doubled.

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Stocks versus Bonds: Explaining the Equity Risk Premium

Clifford S. Asness

From the 19th century through the mid-20th century, the dividend yield (dividends/price) and earnings yield (earnings/price) on stocks generally exceeded the yield on long-term U.S. government bonds, usually by a substantial margin. Since the mid-20th century, however, the situation has radically changed. In addressing this situation, I argue that the difference between stock yields and bond yields is driven by the long-run difference in volatility between stocks and bonds. This model fits 1871–1998 data extremely well. Moreover, it explains the currently low stock market dividend and earnings yields. Many authors have found that although both stock yields forecast stock returns, they generally have more forecasting power for long horizons. I found, using data up to May 1998, that the portion of dividend and earnings yields explained by the model presented here has predictive power only over the long term whereas the portion not explained by the model has power largely over the short term.

The dividend yield on the S&P 500 Index has long been examined as a measure of stock market value. For instance, the well-known Gordon growth model expresses a stock price (or a stock market's price) as the discounted value of a perpetually growing dividend stream:

$$P = \frac{D}{R - G}. \tag{1}$$

where

P = price
D = dividends in Year 0
R = expected return
G = annual growth rate of dividends in perpetuity

Now, solving this equation for the expected return on stocks produces

$$R = \frac{D}{P} + G. \tag{2}$$

Thus, if growth is constant, changes in dividends to price, D/P, are exactly changes in expected (or required) return. Empirically, studies by Fama and French (1988, 1989), Campbell and Shiller (1998), and others, have found that the dividend yield on the market portfolio of stocks has forecasting power for aggregate stock market returns and that this power increases as forecasting horizon lengthens.

Clifford S. Asness is president and managing principal at AQR Capital Management, LLC.

The market earnings yield or earnings to price, E/P (the inverse of the commonly tracked P/E), represents how much investors are willing to pay for a given dollar of earnings. E/P and D/P are linked by the payout ratio, dividends to earnings, which represents how much of current earnings are being passed directly to shareholders through dividends. Studies by Sorenson and Arnott (1988), Cole, Helwege, and Laster (1996), Lander, Orphanides, and Douvogiannis (1997), Campbell and Shiller (1998), and others, have found that the market E/P has power to forecast the aggregate market return.

Under certain assumptions, a bond's yield-to-maturity, Y, will equal the nominal holding-period return on the bond.[1] Like the equity yields examined here, the inverse of the bond yield can be thought of as a price paid for the bond's cash flows (coupon payments and repayment of principal). When the yield is low (high), the price paid for the bond's cash flow is high (low). Bernstein (1997), Ilmanen (1995), Bogle (1995), and others, have shown that bond yield levels (unadjusted or adjusted for the level of inflation or short-term interest rates) have power to predict future bond returns.

This article examines the relationship between stock and bond yields and, by extension, the relationship between stock and bond market returns (the difference between stock and bond expected returns is commonly called the equity risk premium). I hypothesize that the relative yield stocks must provide versus bonds today is driven by the experience of each generation of investors with each asset class.

The article also addresses the observation of many authors, economists, and market strategists that today's dividend and earnings yields on stocks are, by historical standards, shockingly low. I find they are not.

Finally, I report the results of decomposing stock yields into a fitted portion (i.e., stock yields explained by the model presented here) and a residual portion (i.e., stock yields not explained by the model).

Historical Yields on Stocks and Bonds

As far as yields are concerned, 1927–1998 tells a tale of two periods—as **Figure 1** clearly shows. Figure 1 plots the dividend yield for the S&P 500 and the yield to maturity for a 10-year U.S. T-bond from January 1927 through May 1998.[2] Prior to the mid-1950s, the stock market's yield was consistently above the bond market's yield. Anecdotally, investors of this era believed that stocks should yield more than bonds because stocks are riskier investments. Since 1958, the stock yield has been below the bond yield, usually substantially below. As of the latest data in Figure 1 (May 1998), the stock market yield was at an all-time low of 1.5 percent whereas the bond market yield was at 5.5 percent, not at all a corresponding low point. This observation has led many analysts to assert that the role of dividends has changed and that dividend yields in the late 1990s are not comparable to those of the past. Although this assertion may have some merit, I will argue that it is largely unnecessary to explain today's low D/P.

As did dividend yields, the stock market's earnings yields systematically exceeded bond yields early in the sample period, but as **Figure 2** shows, since the late-1960s, earnings yields have been comparable to bond yields and clearly strongly related (as are dividend yields, albeit from a lower level).[3] **Table 1** presents monthly correlation coefficients for various periods between the levels of D/P and Y and E/P and Y. The numbers in Table 1 clearly bear out what is seen in Figures 1 and 2. For the entire period, D/P and Y were negatively correlated because of their reversals; E/P was essentially uncorrelated with Y. For the later period, however, stock and bond yields show the strong positive relationship many economists and market strategists have noted.

Thus, we are left with several puzzles:

- Why did the stock market strongly outyield bonds for so long only to now consistently underyield bonds?
- Why did stock and bond yields move relatively independently, or even perversely, in the overall 1927–98 period but move strongly together in the later 40 years of this period?
- Perhaps most important, why are today's stock market yields so low and what does that fact mean for the future?

The rest of this article tries to answer these questions.

Figure 1. S&P 500 Dividend Yield and T-Bond Yield to Maturity, January 1927–May 1998

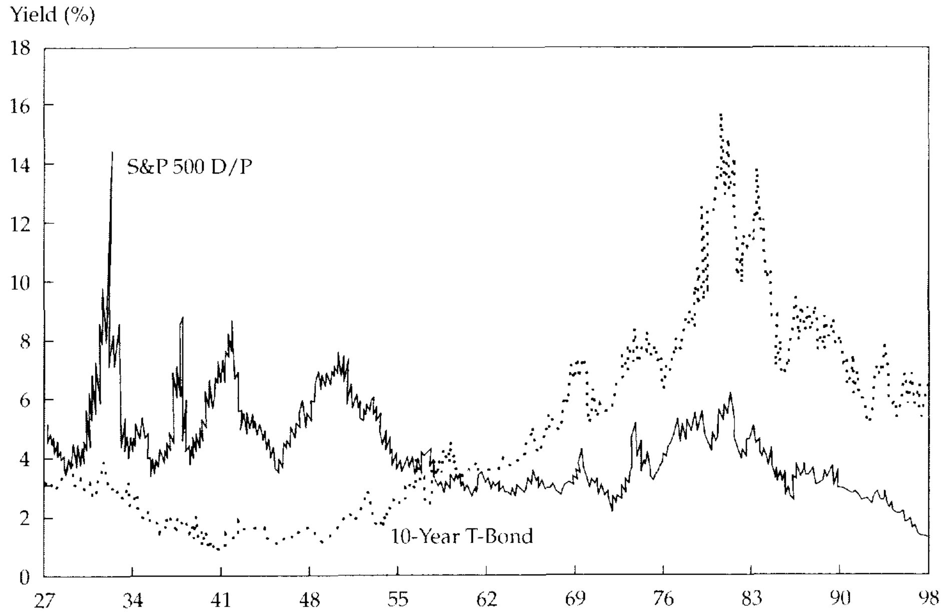


Figure 2. S&P 500 Earnings Yield and T-Bond Yield to Maturity, January 1927–May 1998

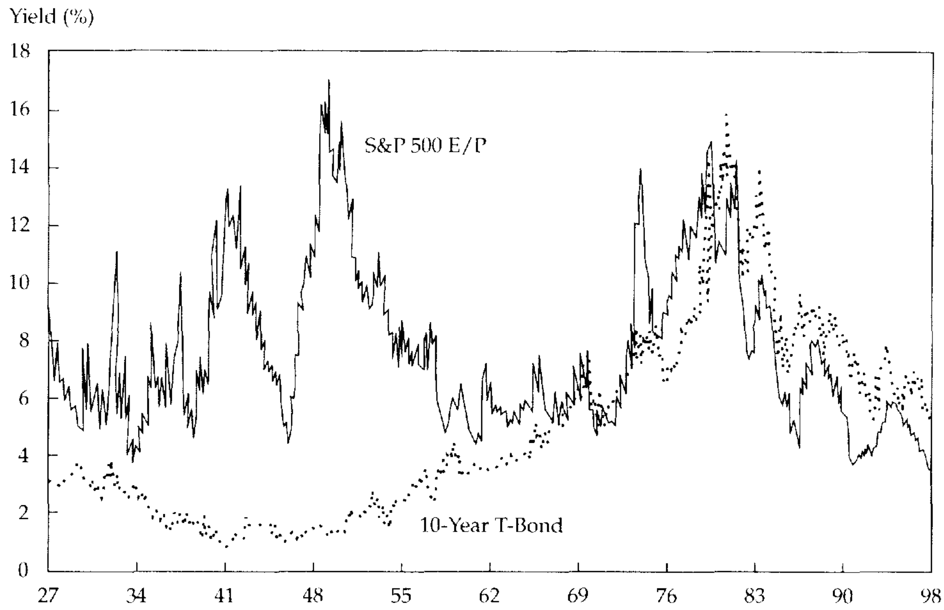


Table 1. Monthly Correlation Coefficients, Various Periods

Period	Correlation of D/P and Y	Correlation of E/P and Y
Full (January 1927–May 1998)	–0.28	+0.08
Early (January 1927–December 1959)	–0.23	–0.49
Late (January 1960–May 1998)	+0.71	+0.69

Model for Stock Market Yields

Researchers have shown a strong link between aggregate dividend and earnings yields and expected stock market returns, especially for long horizons. When stock market yields are high (low), expected future stock returns are high (low). This predictability has two possible explanations that are at least partly consistent with efficient markets (there are many *inefficient*-market explanations). One, investors' taste for risk varies. When investors are relatively less risk averse, they demand less in the way of an expected return premium to bear stock market risk. Fama and French (1988, 1989), among others, explored this hypothesis. Two, the perceived level of risk can change even if investors' taste for risk is constant.

I explore the hypothesis that the perceived level of risk can change (although the two hypotheses are not mutually exclusive). Note that investor perception of long-term risk need not be accurate for this hypothesis to be true. If investor perception of risk is accurate, then the evidence presented here may be consistent with an efficient market. If investor perception of risk is inaccurate but explains the pricing of stocks versus bonds, then the hypothesis may be deemed accurate but still pose a dilemma for fans of efficient markets.

Consider a simple model in which the required long-term returns on aggregate stocks and bonds vary through time. Expected stock returns, E(Stocks), are assumed to be proportional to dividend yields, whereas expected bond returns, E(Bonds), are assumed to move one-for-one with current bond yields; that is,

$$E(\text{Stocks})_t = a + b(\text{D/P}_t) + \varepsilon_{Stocks,t}, \quad (3)$$

$$E(\text{Bonds})_t = Y_t + \varepsilon_{Bonds}, \quad (4)$$

(where a is the intercept, b is the slope, D/P_t is dividend yield at time t, and ε is an error term). The hypothesis is that b is positive, so expected stock returns vary positively with current stock dividend yields, and that the ε terms are identically and independently distributed error terms representing the portion of expected returns not captured by the model.[4]

Now, I assume that expected stock and bond returns are linked through the long-run stock and bond volatility experienced by investors. So,

$$E(\text{Stocks})_t - E(\text{Bonds})_t = c + d\sigma(\text{Stocks})_t + e\sigma(\text{Bonds})_t. \quad (5)$$

The hypothesis is that d is positive whereas e is negative. That is, I assume that the expected (or required) return differential between stocks and bonds is a positive linear function of a weighted difference of their volatilities.[5] Although Equations 3, 4, and 5 do not represent a formal asset-pricing model, they do capture the spirit of allowing expected returns to vary through time as a function of volatility. Moreover, they yield empirically testable implications.[6]

Rearranging these equations (and aggregating coefficients) produces the following model:

$$D/P = \gamma_0 + \gamma_1 Y + \gamma_2 \sigma(\text{Stocks}) + \gamma_3 \sigma(\text{Bonds}) + \varepsilon_{D/P,t}. \quad (6)$$

Now, the hypothesis is that γ_1 is positive, γ_2 is positive, and γ_3 is negative. This model, and the precisely corresponding model for E/P, is tested in the following section.[7] Other authors (e.g., Merton 1980; French, Schwert, and Stambaugh 1987) have tested the link between expected stock returns and volatility by examining the relationship between realized stock returns and *ex ante* measures of volatility.[8] However, as these authors noted, realized stock returns are a noisy proxy for expected stock returns. I believe that linking Equations 3, 4, and 5 and focusing on the long term will reveal a clearer relationship between stock market volatility and expected stock market returns as represented by stock market yield (D/P or E/P).[9]

Preliminary Evidence

To investigate Equation 6, I defined a generation as 20 years and used a simple rolling 20-year annualized monthly return volatility for σ(Stocks) and σ(Bonds).[10] The underlying argument is that each generation's perception of the relative risk of stocks and bonds is shaped by the volatility it has experienced. For instance, Campbell and Shiller (1998) mentioned (but did not necessarily advocate) the argument that Baby Boomers are more risk tolerant "perhaps because they do not remember the extreme economic conditions of the 1930s." Another example is Glassman and Hassett (1999), who argued in *Dow 36,000* that remembrances of the Great Depression have led investors to require too high an equity risk premium.

A 20-year period captures the long-term generational phenomenon that I hypothesized.[11] The hypothesis is inherently behavioral because it states that the long-term, slowly changing relationship between stock and bond yields is driven by the long-term volatility of stocks and bonds experienced by the bulk of current investors. Although I believe a 20-year period is intuitively reasonable, given the hypothesis, I am encouraged by the fact that the results that follow are robust to alternative specifications of long-term volatility (i.e., from 10-year to 30-year trailing volatility) and still showed up significantly when windows as short as 5 years were used.

The regressions in this section are simple linear regressions that do not account for some significant econometric problems; for example, the following regressions have highly autocorrelated independent variables, dependent variables, and residuals. But the goal of these regressions is to initially establish the existence of an economically significant relationship. Because statistical inference is problematic, I do not focus on (but do report) the t-statistics. The focus is on the economic significance of the estimated coefficients and R^2 figures. (Subsequent sections explore the issue of statistical significance and report robustness checks.)

Because I required 20 years to estimate volatility and the monthly data began in 1926, I estimated Equation 6 by using monthly data from January 1946 through May 1998. Before examining this equation in full, I first examine the regression of D/P on bond yields only and D/P on the rolling volatility of stock and bond markets only for the 1946–98 period (the first data points are dividend and bond yields in January 1946 and stock and bond volatility estimated from January 1926 through December 1945; the t-statistics are in parentheses under the equations. The results are as follows:

$$\begin{aligned} D/P = {} & \underset{(40.72)}{4.10\%} - \underset{(-2.26)}{0.03Y} \end{aligned} \quad (7)$$

(with an adjusted R^2 of 0.7 percent) and

$$D/P = \underset{(11.87)}{2.02\%} + \underset{(18.96)}{0.14\sigma(\text{Stocks})} - \underset{(-5.24)}{0.07\sigma(\text{Bonds})} \quad (8)$$

(with an adjusted R^2 of 43.0 percent).[12]

Equation 7 shows that D/P and Y have a mildly negative relationship for 1946–1998, similar to what I found for the entire 1926–98 period (Table 1). Equation 8 shows that a significant amount of the variance of D/P (note the adjusted R^2) is explained by stock and bond volatility, with D/P rising with stock market volatility and falling with bond market volatility. This relationship is economically significant. An increase in stock market volatility from 15 percent to 20 percent, all else being equal, raises the required dividend yield on stocks by 70 basis points (bps). Now, note the estimate for Equation 6:

$$D/P = \underset{(-0.05)}{0.00\%} + \underset{(28.77)}{0.35Y} + \underset{(39.51)}{0.23\,\sigma(\text{Stocks})} - \underset{(-25.69)}{0.31\sigma(\text{Bonds})} \quad (9)$$

(with an adjusted R^2 of 75.4 percent).

This result supports the hypothesis. The dividend yield is mildly negatively related to the bond yield when measured alone (Equation 7), but this negative relationship is a highly misleading indicator of how stock and bond yields covary. When I adjusted for different levels of volatility, I found stock and bond yields to be strongly positively related. My interpretation of this regression is that stock and bond market yields are strongly positively related and the difference between stock and bond yields is a direct positive function of the weighted difference between stock and bond volatility. Intuitively, the more volatile stocks have been versus bonds, the higher the yield premium (or smaller a yield deficit) stocks must offer. In any case, when volatility is held constant, stock yields do rise and fall with bond yields.

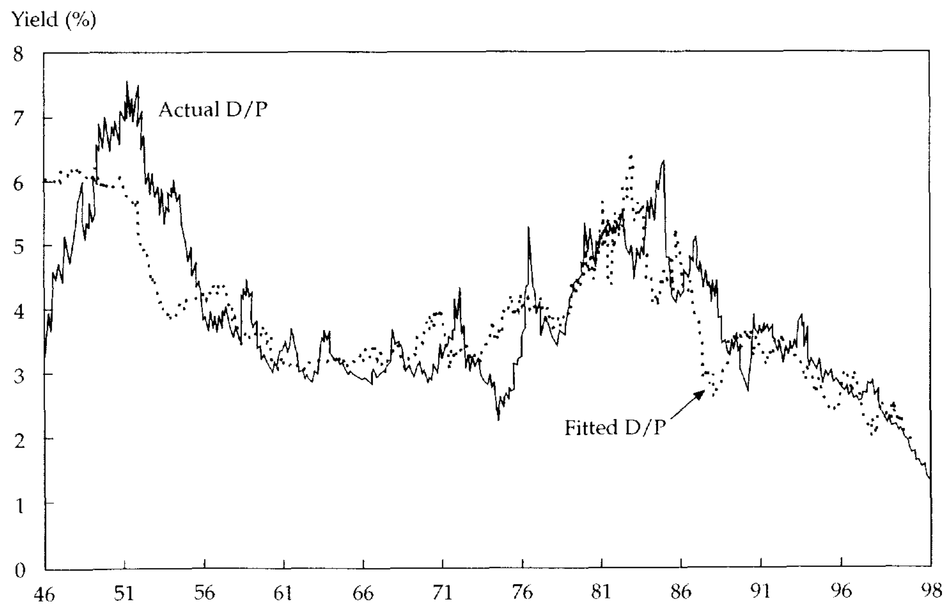
Again, these results are economically significant. For example, a 100 bp rise in bond yields translates to a 35 bp rise in the required stock market dividend yield, whereas a rise in stock market volatility from 15 percent to 20 percent leads to a rise of 115 bps in the required stock market dividend yield.

The fact that stock and bond yields are univariately unrelated (or even negatively related) over long periods (Table 1) is a result of changes in relative stock and bond volatility that obscure the strong positive relationship between stock and bond yields. The reason stock and bond yields are univariately positively related over shorter periods (e.g., 1960–1998) is because of the stable relationship between stock and bond volatility over short periods. In other words, a missing-variable problem is not much of a problem if the missing variable was not changing greatly during the period being examined (such as in 1960–1998). The problem is potentially destructive, however, if the missing variable varied significantly during the period (such as in 1927–1998).

Figure 3 presents the actual market D/P and the in-sample D/P fitted from the regression in Equation 9. **Figure 4** presents the residual from this regression (actual D/P minus fitted D/P). For today's reader, perhaps the most interesting part of Figures 3 and 4 is the latest results. The actual D/P at the end of May 1998 (the last data point) is 1.5 percent, a historic low. The forecasted D/P is also at a historic low, however—2.1 percent—which is a forecasting error of only 60 bps.

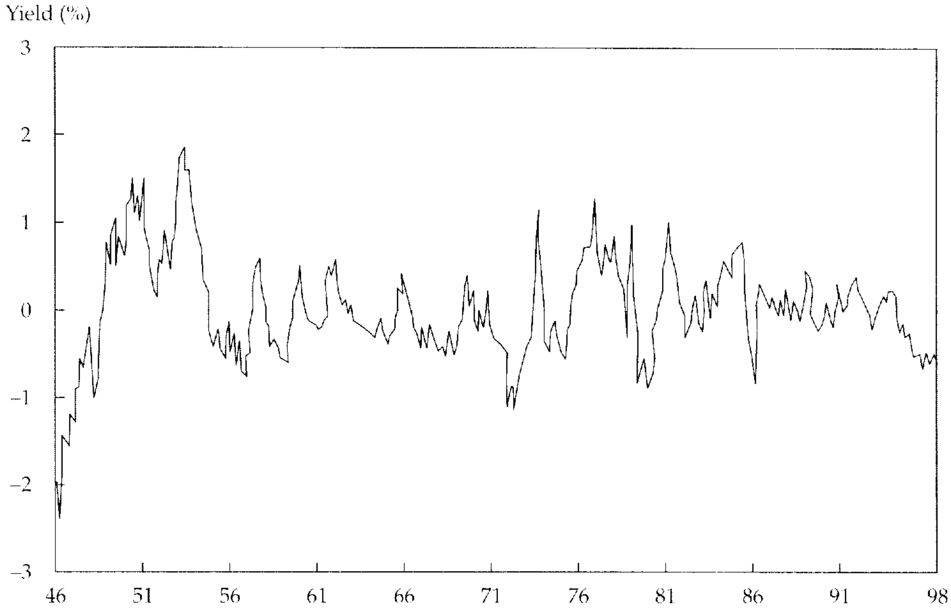
Simply examining the D/P series leads to a belief that recent D/Ps are shockingly low. These regressions suggest a different interpretation: Given the recent low bond yields and a low realized differential in volatility between stocks and bonds, I would forecast an all-time historically low D/P for stocks as of May 1998. The fact that the model does not forecast the actual low in dividend yield is not statistically anomalous (May's forecast error is about 1 standard deviation below zero) and may be a result of the stories other authors have cited to explain today's low D/P (e.g., stock buy-backs

Figure 3. Actual S&P 500 Dividend Yield and In-Sample Dividend Yield, January 1946–May 1998



Note: In-sample D/P fitted from the regression in Equation 9.

Figure 4. Regression Residual: Actual D/P minus Fitted D/P, January 1946–May 1998



replacing dividends). But these stories might not be at all necessary. For example, the story of stock buybacks replacing dividends has been around since at least the late 1980s (Bagwell and Shoven 1989), yet the average in-sample forecasting error of my model for D/P for 1990–1998 is only –9 bps. Apparently, nothing more than Equation 9 is needed to explain recent low dividend yields.

Running a similar regression for E/P, I obtained the following result:

$$\underset{(-3.70)}{E/P = -1.39\%} + \underset{(27.33)}{0.96Y} + \underset{(29.58)}{0.49\sigma(\text{Stocks})} - \underset{(-21.56)}{0.76\sigma(\text{Bonds})} \quad (10)$$

(with an adjusted R^2 of 64.8 percent). The model explains about as much of the variance for earnings yield as dividend yield. As of the end of May 1998, the E/P for the S&P 500 was 3.6 percent, corresponding to a P/E of 27.8. The forecasted E/P from the Equation 10 regression is 3.4 percent, or a forecasted P/E ratio of 29.1. Unlike the case for D/P, I am not (even to a small degree) failing to explain the recent high P/Es on stocks; rather, one would have to explain the opposite, because according to the model, the May 1998 P/E of 27.8 is slightly *lower* than it should be.

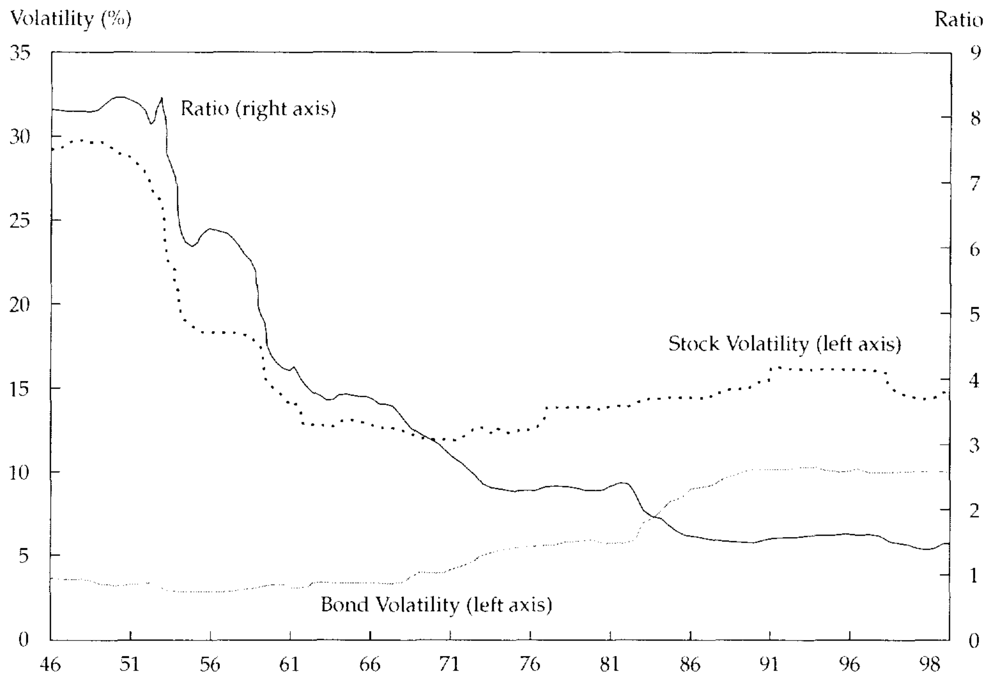
Again, these results are economically significant: The required earnings yield was moving virtually one-for-one with 10-year T-bond yields and increasing 245 bps for each 5 percent rise in stock market volatility (all else being equal). Examining Figure 2 and Table 1 shows that E/P and Y were strongly positively correlated only for the later period of the sample (in the earlier period, they were actually negatively correlated, and for the whole period, they were close to uncorrelated). When changing stock- and bond-market volatility is accounted for in Equation 10, however, the strong positive relationship between E/P and Y is extended to the full period.

Critique and Further Evidence

The regression results presented in the previous section fit intuition and the hypothesis as formalized in Equation 6, but they are certainly open to criticism. They are in-sample regression results and are thus particularly open to charges of data mining. They are level-on-level regressions, which renders the t-statistics invalid and makes the high R^2 figures potentially spurious.[13] Worse, they are level-on-level regressions that use 20-year rolling data and a highly autocorrelated dependent variable.[14] Because the inference is suspect, stock and bond volatility may have followed a pattern that explained a secular-level change in dividend and earnings yield merely by chance.

To examine this possibility, **Figure 5** shows the rolling 20-year volatilities of the stock and bond markets used in the preceding regressions and the ratio of stock to bond volatility. Aside from the very early and very late years of the period, the ratio of rolling 20-year stock volatility to bond volatility was dropping nearly monotonically from 1946 through mid-1998. Thus, a hypothesis that fits the regression results and Figure 5 is that stock yields and bond yields are positively related but, exogenous to this relationship, the level of stock yields has been declining over time.

Figure 5. Rolling 20-Year Volatilities of Stock and Bond Markets and Ratio of Stock to Bond Volatility, January 1946–May 1998



The issue is one of causality. Was the drop in the level of stock yields versus that of bond yields occurring because of changes in their relative experienced volatilities (as I hypothesize), or were other factors causing this drop through time and thus producing spurious regression results? A 50-year regression that uses 20-year rolling data makes answering this question difficult. So, the next subsections attempt to explore this critique.

Performance of the Model versus a Time Trend. If the drop in stock yields versus bond yields is coincidentally, not causally, related to volatility, then a time trend might do as well as volatility in the regression tests. For ease of comparison, recall the results for D/P regressed on bond yields and stock and bond volatility; Equation 9 was

$$\underset{(-0.05)}{D/P = 0.00\%} + \underset{(28.77)}{0.35Y} + \underset{(39.51)}{0.23\,\sigma(\text{Stocks})} - \underset{(-25.69)}{0.31\sigma(\text{Bonds})},$$

and the adjusted R^2 was 75.4 percent. The next equations report similar regressions in which, instead of stock and bond volatility, either a linear or loglinear time trend was used:

$$D/P = \underset{(51.44)}{6.18\%} + \underset{(14.69)}{0.25(Y)} - \underset{(-21.97)}{0.00}(\text{Linear trend}) \quad (11)$$

(with an adjusted R^2 of 43.8 percent) and

$$D/P = \underset{(32.32)}{27.97\%} + \underset{(19.88)}{0.33(Y)} - \underset{(-27.61)}{0.04}(\text{Loglinear trend}) \quad (12)$$

(with an adjusted R^2 of 55.1 percent).

The time-trend variables capture much of the effect being studied. That is, the relationship between D/P and Y goes from weakly negative (Equation 7) to strongly positive in the presence of the trend variable—meaning that the expected difference between stock and bond yields was declining through time and, after accounting for this trend, stock and bond yields were positively related. The volatility-based regression, however, is clearly the strongest: The adjusted R^2 is higher, and the coefficient on bond yields is larger and more significant.

Next, the loglinear time trend is added to Equation 9 to see how the volatility variables fare in head-on competition:

$$D/P = \underset{(-3.98)}{-10.00\%} + \underset{(28.50)}{0.35Y} + \underset{(19.63)}{0.28\sigma}(\text{Stocks}) \quad (9a)$$

$$- \underset{(-11.87)}{0.46\sigma}(\text{Bonds}) + \underset{(3.99)}{0.02}(\text{Loglinear trend})$$

(with an adjusted R^2 of 76.0 percent).

Clearly, the volatility variables drive out the time trend (analogous results held for the linear time trend) to the point at which the trend's coefficient is slightly positive (the wrong sign). Although the nearly monotonic fall in bond versus stock volatility makes it hard to distinguish between causality and coincidence for the 1946–98 period, the superiority of the volatility-based model over a time trend gives comfort. Analogous results favoring the volatility model were found for E/P.

Rolling Regression Forecasts. I formed rolling out-of-sample forecasts of D/P starting with January 1966. (I began in 1966 because I needed the 20 years from 1926 to 1946 to estimate volatility and the 20 years from 1946 to 1966 to formulate the first predictive regression.) The regressions used an "expanding window" that always started in January 1946 and went up to the month before the forecast.

For comparison purposes, I formed these forecasts based on five models. Model 1 attempted to forecast D/P by using only the average D/P (so the forecast of D/P on January 1966 was the average D/P from January 1946 through December 1965). Model 2 attempted to forecast D/P by using a rolling regression on bond yields only. Model 3 used a rolling version of the complete model from Equation 9 (a regression on bond yields, stock volatility, and bond volatility). Model 4 and Model 5 corresponded to rolling versions of, respectively, the linear trend model in Equation 11 and the loglinear trend model in Equation 12. **Table 2** presents the results of these out-of-sample forecasts.

The volatility-based Model 3 was nearly unbiased over the 1966–98 period, had the lowest absolute bias of any of the five models, and had the lowest standard deviation of forecast error. The out-of-sample rolling regressions thus support the superiority of the volatility model, although again, the time-trend models are somewhat effective when compared with the more naive Models 1 and 2.

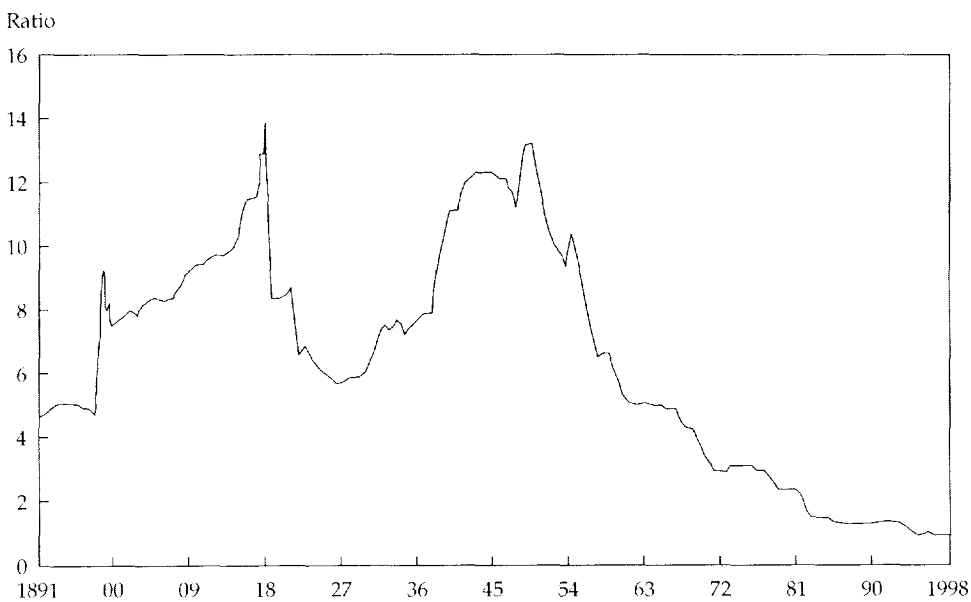
Earlier Data. The best response to many statistical problems is extensive out-of-sample testing—that is, tests with data for a previously unexamined period. All of the tests so far used monthly data for the commonly studied period commencing in 1926. For the tests reported in this section, I used earlier data. Although perhaps not as reliable as the modern data, annual data on the aggregate stock and bond markets are available for as early as 1871.[15]

In addition to simply using new data points, examining the older information provides an advantage that is specific to this study. In **Figure 6**, the new data are used to plot the ratio of rolling 20-year stock market volatility to rolling 20-year bond market volatility over the entire 1891–1998 period.[16]

Table 2. Out-of-Sample Forecasts, January 1966–May 1998

Model	Average Forecasting Error	σ(Forecasting error)
1. Using average D/P	–0.56%	0.97%
2. Using regression on Y	0.29	1.38
3. Using the full model	0.14	0.50
4. Using linear time trend	0.71	0.66
5. Using loglinear time trend	0.54	0.62

Figure 6. Ratio of Rolling 20-Year Stock Market Volatility to Bond Market Volatility, January 1891–May 1998



Recall that one problem with testing the hypothesis for 1946–1998 was that the volatility ratio declined nearly monotonically. Figure 6 shows that the new data preserve this property for this same time period but that the 1891–1945 period reflects no monotonic trend. Thus, if the model works for 1891–1945, or 1891–1998, a spurious time trend is not driving the results. I found that dividend yields also trended down strongly over the 1946–98 period but appear much more stationary when viewed over the entire 1891–1998 period (this figure is available upon request).

As a data check, before examining the pre-1946 data, I reexamined the 1946–98 period with the new annual data set. The following are *annual* regressions for the already-studied 1946–98 period:

$$\underset{(10.78)}{D/P = 4.12\%} - \underset{(-0.65)}{0.04Y} \tag{13}$$

(with an adjusted R^2 of –1.1 percent);

$$D/P = \underset{(-1.64)}{-1.15\%} + \underset{(6.07)}{0.29Y} + \underset{(8.03)}{0.24\sigma(\text{Stocks})} - \underset{(-4.88)}{0.16\sigma(\text{Bonds})} \tag{14}$$

(with an adjusted R^2 of 66.0 percent;

$$E/P = \underset{(7.57)}{6.98\%} + \underset{(0.95)}{0.13Y} \tag{15}$$

(with an adjusted R^2 of –1.8 percent);

$$E/P = \underset{(-1.64)}{-3.12\%} + \underset{(6.07)}{0.85Y} + \underset{(8.03)}{0.46\sigma(\text{Stocks})} - \underset{(-4.88)}{0.40\sigma(\text{Bonds})} \tag{16}$$

(with an adjusted R^2 of 48.9 percent).

Although not precisely the same as the monthly regressions presented earlier, the annual regressions on the new data set are similar enough to be encouraging.

Now, consider the results for these same regressions for the earlier 1891–1945 data:

$$D/P = \underset{(2.70)}{2.60\%} + \underset{(2.72)}{0.77Y} \tag{17}$$

(with an adjusted R^2 of 10.6 percent);

$$D/P = \underset{(-1.18)}{-1.65\%} + \underset{(5.00)}{1.36Y} + \underset{(4.75)}{0.19\sigma(\text{Stocks})} - \underset{(-2.10)}{0.53\sigma(\text{Bonds})} \tag{18}$$

(with an adjusted R^2 of 35.7 percent);

$$E/P = \underset{(2.20)}{4.20\%} + \underset{(1.90)}{1.06Y} \tag{19}$$

(with an adjusted R^2 of 4.6 percent);

$$E/P = \underset{(1.05)}{2.90\%} + \underset{(3.13)}{1.68Y} + \underset{(3.15)}{0.25\sigma(\text{Stocks})} - \underset{(-4.50)}{2.23\sigma(\text{Bonds})} \tag{20}$$

(with an adjusted R^2 of 31.5 percent).

These regressions provide bad news and good news. The bad news is that some of the regression coefficients are very different for the 1891–1945 period from what they were for the 1946–98 period. Apparently, the (admittedly simple) model is not completely stable over time. Given changes in the world economy from 1871 to 1998, to think that the coefficients would be completely stable is perhaps wildly optimistic.[17] The good news is that, although over the 1891–1945 period the stock market's D/P and E/P were univariately weakly positively related to Y (see Equations 17 and 19), this relationship became much more strongly positive when I allowed for changing relative stock and bond market volatilities (as in the completely separate 1946–98 period). This relationship was, as my hypothesis forecasted, a strong positive function of the previous 20 years' relative stock versus bond volatility.

Finally, I present the regressions for D/P for the full 1891–1998 period. For comparison, I also present full-period tests of the time-trend variables (the E/P results were highly analogous for all regressions):[18]

$$D/P = \underset{(17.79)}{5.20\%} - \underset{(-2.53)}{0.14Y} \tag{21}$$

(with an adjusted R^2 of 4.8 percent);

$$D/P = \underset{(17.32)}{5.90\%} + \underset{(0.42)}{0.03Y} - \underset{(-3.54)}{0.00\text{Linear trend}} \tag{22}$$

(with an adjusted R^2 of 14.1 percent);

$$D/P = \underset{(6.09)}{7.75\%} - \underset{(-0.91)}{0.06Y} - \underset{(-2.06)}{0.07\text{Loglinear trend}} \tag{23}$$

(with an adjusted R^2 of 7.6 percent);

$$D/P = \underset{(2.96)}{1.98\%} + \underset{(3.52)}{0.26Y} + \underset{(4.95)}{0.14\sigma(\text{Stocks})} - \underset{(-5.65)}{0.29\sigma(\text{Bonds})} \tag{24}$$

(with an adjusted R^2 of 35.5 percent).

The earlier data and the full-period data strongly support the central tenet of the hypothesis: Without adjusting for volatility and with or without a time trend (Equations 21–23), either a negative or flat relationship appears between D/P and bond yields over the entire period. After adjustment for relative stock and bond volatility, this relationship is strongly positive (Equation 24). Unlike the 1946–98 results, these results are clearly present in the absence of a significant trend in the ratio of stock to bond market volatility and despite any changes in the world economy from 1871 to 1998. In fact, unlike the volatility-based model, the time trends utterly fail to resurrect the positive relationship between stock and bond yields over the full period. When I used the data for 1946–1998, I introduced the issue of distinguishing whether the volatility-based model was spuriously supported because the changes in relative volatility approximated a time trend. The earlier and full-period evidence powerfully indicates that it is the time trend whose efficacy is spurious for 1946–1998, not the volatility-based model.

Full-Period Scatter Plots. As a final and perhaps most compelling test, I examined nonoverlapping 20-year periods from 1878 until 1998. I report the results for the resulting six observations in **Figure 7**. Figure 7 plots the ratio of annualized monthly stock market volatility over corresponding monthly bond volatility for the 20 years ending before the labeled year against the excess of stock market earnings yields over bond yields for the year in question. I chose earnings yields for this investigation because the evidence is that they are directly close to being comparable to bond market yields whereas dividend yields move as a dampened function of bond yields (that is, the coefficient on *Y* in Equation 10 is nearly 1.0, which makes the simple difference relevant to examine).

Figure 7 clearly supports the model: The greater stock volatility is versus bond volatility, the higher E/P must be versus *Y*. In contrast to the earlier regression tests, which were admittedly an econometric nightmare, nonoverlapping observations were used for Figure 7, and the autocorrelation of both the dependent and independent series was close to zero.[19] Thus, any need for econometric corrections (e.g., first differencing) was avoided.

The problem now is that I have only six observations, so the tests might lack power, but this is not the case. The *t*-statistic of the regression line is +7.64, and the adjusted R^2 is 92.0 percent. With six observations, a *t*-statistic must exceed +2.45 to be significant at a *p* value of 2.5 percent in a one-tailed test. Clearly, the *t*-statistic for this test is well past this level of significance.

As a robustness check, I recreated Figure 7 but starting 10 years later (resulting in only five observations over this period). The results are in **Figure 8**. This figure is even more striking than Figure 7 (the *t*-statistic in Figure 8 is +12.46, and the adjusted R^2 is 97.5 percent). Note from Figure 6 (the graph of the rolling volatility ratio) that two peaks are visible in the ratio of stock to bond volatility. These peaks roughly correspond to the right side of, respectively, Figures 7 and 8. In both cases, the model fits these extreme observations exceptionally well (that is, the largest volatility ratio corresponded to the largest end-of-period gap of stock earnings yield over bond yield). Also note that these two periods (the 20 years ending in 1918 and the 20 years ending in 1948) share no overlapping observations, yet the model fits both perfectly.

Figure 7. Ratio of Annualized Monthly Stock Market Volatility to Corresponding Monthly Bond Volatility versus Excess of Stock Market Earnings Yield over Bond Yield, 1871–May 1998

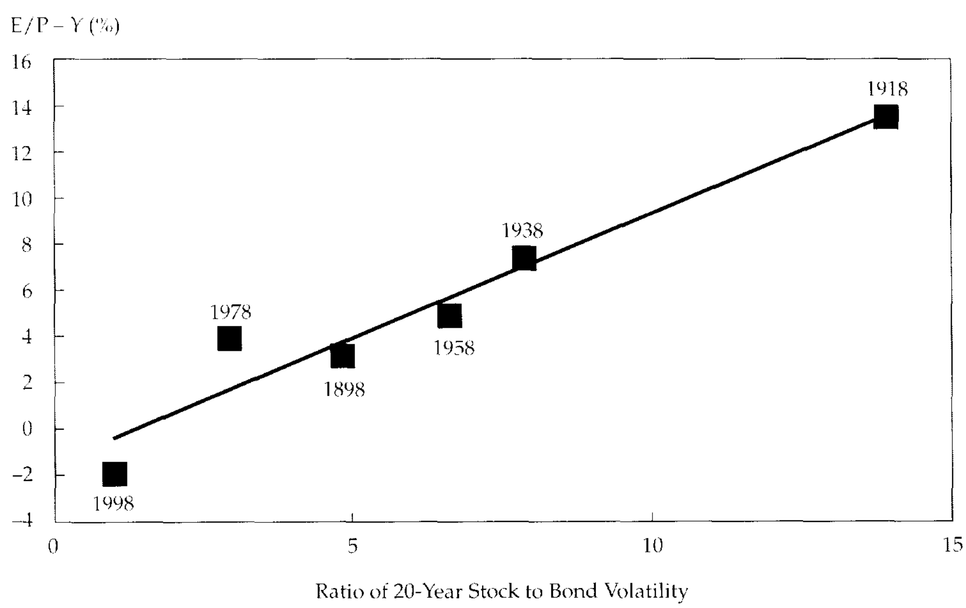
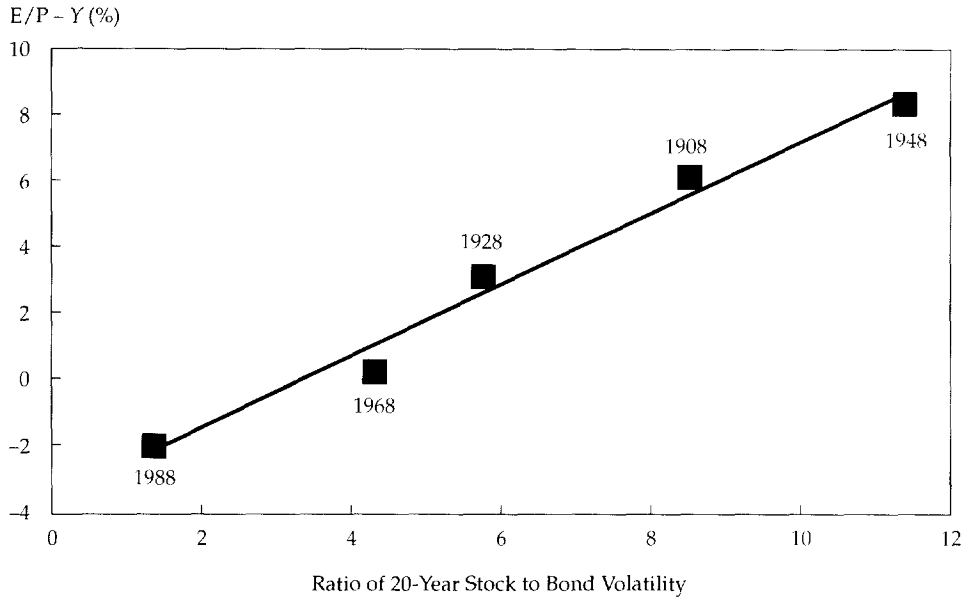


Figure 8. Ratio of Annualized Monthly Stock Market Volatility to Corresponding Monthly Bond Volatility versus Excess of Stock Market Earnings Yield over Bond Yield, 1881–May 1998



Finally, for completeness, I present in **Table 3** the adjusted R^2 and t-statistics for each of eight possible regressions on nonoverlapping periods for which I have six 20-year data points (each row in Table 3 presents the results of a regression that differs by one year in its starting and ending point from the prior/next row). Only one of these eight regressions produced results well below traditional levels of significance, and even in this case, the sign is correct.[20]

We believe these nonoverlapping tests are compelling evidence, irrespective of the econometric problems with our earlier tests, that following long-term periods of high (low) stock market volatility relative to bond market volatility, the required yield on stocks is relatively high (low) versus bonds.

Table 3. Statistics for Eight Regressions

Period	Adjusted R^2	t-Statistic
1891–1991	88.5%	+6.28
1892–1992	73.7	+3.87
1893–1993	81.0	+4.72
1894–1994	45.6	+2.28
1895–1995	9.9	+1.25
1896–1996	91.5	+7.42
1897–1997	78.3	+4.36
1898–1998	92.0	+7.64
Mean	70.1	+4.73
Median	79.7	+4.54

Note: Each row presents the results of a regression that differs by one year in its starting and ending point from the prior/next row.

Market Predictability

Researchers have found that variables D/P and E/P have power to forecast aggregate stock market returns. Moreover, this power appears to increase as time horizon lengthens (e.g., Fama and French 1988, 1989). I tested this finding for 1946–1998 using predictive regressions of excess monthly and annualized 5- and 10-year compound S&P 500 returns on aggregate D/P (t-statistics on all multiperiod regressions were adjusted for overlapping observations and heteroscedasticity). Here are the findings:

$$\text{S\&P monthly return} = \underset{(-1.03)}{-0.56\%} + \underset{(2.38)}{0.32\text{D/P}} \quad (25)$$

(with an adjusted R^2 of 0.7 percent);

$$\text{S\&P 5-year return} = \underset{(-0.88)}{-4.13\%} + \underset{(4.77)}{4.09\text{D/P}} \quad (26)$$

(with an adjusted R^2 of 56.1 percent);

$$\text{S\&P 10-year return} = \underset{(-0.38)}{-1.443\%} + \underset{(4.34)}{3.22\text{D/P}} \quad (27)$$

(with an adjusted R^2 of 58.7percent).

Equations 25–27 verify the findings of other authors that D/P has weak, but statistically significant, power for forecasting monthly returns and strong statistically significant power for forecasting longer-horizon returns.

Now, a new predictive variable, D/P(Error), is introduced. It is the in-sample residual term from the regression of D/P on Y, σ(Stocks), and σ(Bonds) for the 1946–98 period (Equation 9). It represents the

D/P on the S&P 500 in excess or deficit of what I would have predicted had I been using this model to forecast D/P (i.e., the unexplained portion). The results of the same regression tests as done for Equations 25–27 on this new variable are as follows (all results of this section were analogous when tested on E/P):

$$\underset{}{\text{S\&P monthly return}} = \underset{(4.29)}{0.67\%} + \underset{(6.74)}{1.75}\text{D/P(Error)} \quad (28)$$

(with an adjusted R^2 of 6.6 percent);

$$\text{S\&P 5-year return} = \underset{(6.50)}{12.60\%} + \underset{(3.00)}{4.65}\text{D/P(Error)} \quad (29)$$

(with an adjusted R^2 of 21.2 percent);

$$\text{S\&P 10-year return} = \underset{(5.64)}{12.08\%} + \underset{(1.35)}{2.01}\text{D/P(Error)} \quad (30)$$

(with an adjusted R^2 of 7.1 percent).

Comparing the results for D/P(Error) with D/P shows that D/P(Error) has far more predictive power than D/P at short (monthly) horizons but far less power at longer horizons.[21] The power of D/P(Error) to forecast short-horizon returns can be interpreted as picking up time-varying risk aversion or, alternatively, as market mispricing (I leave this decision to future work). In either case, when D/P(Error) is high, stocks are selling for lower prices than is usual in the same interest rate and volatility environment and those low prices indicate higher short-horizon expected returns (and vice versa).

Finally, I formed D/P(Fit) as the fitted values from regression Equation 9. D/P(Fit) can be interpreted as the normal dividend yield as forecasted by the model considering the level of bond yields and stock and bond market volatility. By construction, the following relationship holds:

$$\text{D/P} = \text{D/P(Fit)} + \text{D/P(Error)}. \quad (31)$$

By regressing stock returns on both D/P(Fit) and D/P(Error), I decomposed the forecasting power of D/P into a portion coming from fitted D/P and a portion coming from residual D/P. The following regressions were carried out for 1946–98 data:[22]

$$\text{S\&P monthly return} = \underset{(2.07)}{1.25\%} - \underset{(-0.99)}{0.15}\text{D/P(Fit)} + \underset{(6.74)}{1.75}\text{D/P(Error)} \quad (32)$$

(with an adjusted R^2 of 6.6 percent);

$$\text{S\&P 5-year return} = \underset{(-0.56)}{-2.80\%} + \underset{(3.93)}{3.77}\text{D/P(Fit)} + \underset{(4.97)}{4.96}\text{D/P(Error)} \quad (33)$$

(with an adjusted R^2 of 57.1 percent);

$$\text{S\&P 10-year return} = \underset{(-0.76)}{-3.00\%} + \underset{(4.81)}{3.61}\text{D/P(Fit)} + \underset{(2.00)}{2.29}\text{D/P(Error)} \quad (34)$$

(with an adjusted R^2 of 61.1 percent).

Clearly, the power of D/P for predicting short-run (monthly) S&P 500 returns is driven by D/P(Error). As horizon lengthens, D/P(Fit) becomes more and more important, and at the 10-year horizon, D/P(Fit) is considerably more important.

To examine even longer forecast horizons and over longer periods, I again used annual data back to 1871 and formed D/P(Fit) and D/P(Error) from Equation 24. Recall that the first 20 years are needed to estimate volatility, so the following regressions are for 1891–1998 (all returns are annualized compound returns):

$$\text{S\&P annual return} = \underset{(1.89)}{18.1\%} - \underset{(-0.71)}{1.46}\text{D/P(Fit)} + \underset{(1.91)}{2.89}\text{D/P(Error)} \quad (35)$$

(with an adjusted R^2 of 2.0 percent);

$$\text{S\&P 5-year return} = \underset{(0.59)}{5.32\%} + \underset{(0.51)}{0.99}\text{D/P(Fit)} + \underset{(3.67)}{2.32}\text{D/P(Error)} \quad (36)$$

(with an adjusted R^2 of 12.2 percent);

$$\text{S\&P 10-year return} = \underset{(-0.21)}{-1.78\%} + \underset{(1.43)}{2.43}\text{D/P(Fit)} + \underset{(1.89)}{0.81}\text{D/P(Error)} \quad (37)$$

(with an adjusted R^2 of 12.4 percent);

$$\text{S\&P 15-year return} = \underset{(-3.91)}{-10.89\%} + \underset{(9.72)}{4.24}\text{D/P(Fit)} + \underset{(0.43)}{0.18}\text{D/P(Error)} \quad (38)$$

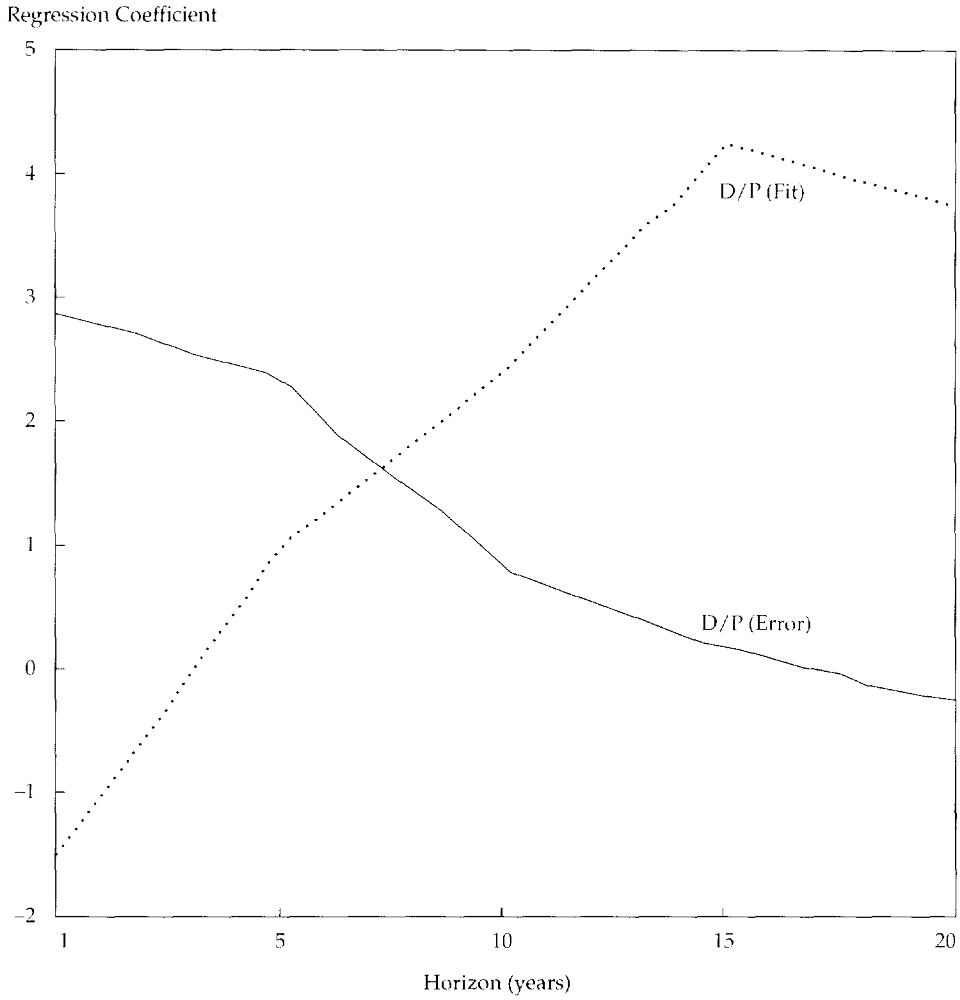
(with an adjusted R^2 of 33.7 percent);

$$\text{S\&P 20-year return} = \underset{(-2.36)}{-8.66\%} + \underset{(5.58)}{3.74}\text{D/P(Fit)} - \underset{(-2.08)}{0.29}\text{D/P(Error)} \quad (39)$$

(with an adjusted R^2 of 42.2 percent).

The estimated coefficients of D/P(Fit) and D/P(Error) for each of the forecast horizons (regression Equations 35–39) are plotted in **Figure 9**. Although annual predictability (Equation 35) is weak, the short-term predictability present is clearly driven by D/P(Error). The story changes dramatically as horizon increases, until at long

Figure 9. Estimated Coefficients of D/P(Fit) and D/P(Error) for Each Forecast Horizon, 1891–1998



Note: All returns are annualized compound returns.

horizons (15 years and 20 years), D/P(Fit) is clearly adding considerable predictive power whereas D/P(Error) is adding none. Figure 9 tells a clear story that at short horizons, D/P(Error) is what counts but at long horizons, what counts is D/P(Fit). (Analogous results held for E/P.)

To sum up, the forecasting power of D/P can be decomposed into the forecasting power of D/P(Fit) and D/P(Error). In the model, D/P(Fit) is the normal or expected dividend yield, and D/P(Error) is interpreted as the D/P in excess (or deficit) of normal. Evidence presented here indicates that D/P itself forecasts stock returns at both long and short horizons but for different reasons. D/P(Fit) forecasts long-horizon stock returns but has almost no power for the short term. D/P(Error) forecasts short-horizon stock returns but has little power for the long term.

Do Stock Yields Have Farther to Fall?

Many have wondered lately why the market is currently selling at such a historically low D/P and E/P (or high P/D and P/E). In particular, in the book *Dow 36,000*, Glassman and Hassett came to an extreme conclusion. They argued that the reason stock prices seem so high relative to measures such as dividends and earnings is that the expected (or required) return on the stock market is going down as investors realize that the stock market is less risky in relation to the bond market than previously thought. Furthermore, they reasoned that this fall in expected returns is not over yet and concluded that it will not stop until stock and bond market expected returns are equal (a point at which, by their calculations, the Dow will reach approximately 36,000). Part of their reasoning sounds much like the arguments advanced here. Well, part of it is, and part of it is not.

Their first conclusion is 100 percent consistent with this article: the conclusion that stocks have low yields now because they are perceived to be less risky versus bonds than historically normal. In fact, my central thesis is that the return required by investors to own stocks versus bonds varies directly with the perceived relative risk of the two assets (for which I used their respective rolling 20-year volatilities as proxies). I believe that my model, coupled with currently low bond market yields and a low perceived risk of stocks versus bonds, entirely explains, within the bounds of statistical error, today's low yields on stocks (and, according to the model, the low long-term expected returns that come with low yields). Thus, my work strongly supports one aspect of the argument in *Dow 36,000*, namely, that stock market expected returns versus bonds have come down as investor perceptions of the relative risk of stocks versus bonds have changed.

My conclusions differ, however, from the next conclusion of *Dow 36,000*. Glassman and Hassett extrapolated the trend in lowered return-premium expectations to continue, but my model offers them no support. The authors of *Dow 36,000* stated that the fall in stock expected returns is not over yet and will not be complete until the expected return on stocks is the same as bonds (presumably not yet the case) because the authors believe that stocks are no riskier than bonds in the long term. This hypothesis is quite provocative. If stocks are no riskier than bonds, then stock prices should rise as investors realize stocks are currently priced as if they are more risky. Now, much debate involves the long-run risk of stocks versus bonds, and to review or settle this matter is not the province of this paper.[23] However, much of the reason behind the current prominence of this debate in the first place is how different today appears from the past (i.e., today's historically high stock prices versus dividends or earnings). My conclusion is that, in fact, the structure of the world really is not much different today; only the inputs to the model have changed. In other words, stock yields (and required returns) have always moved with bond yields, and the relative difference between them has always been a function of their relative perceived volatility. In fact, when I directly estimated this relationship, I found that it fits well for the long term and fits well today.

The reason the study reported here is a problem for theories like those proposed in *Dow 36,000* is that I say the rise in stock prices today, rather than simply beginning as investors start to perceive how safe stocks really are, is actually proceeding much as it has throughout financial history. According to the model, investors have repriced stocks to reflect a lower perception of stock market risk, but any farther drop in the required return on stocks (and concurrent rise in stock prices) must come from a further reduction in actual stock volatility (versus bond volatility) or a reduction in bond yields. If investors have been all along implicitly using the relationship hypothesized here to price stocks (as the data strongly support they have since at least 1891), then they have acted consistently in recently raising the price of equities. But we can expect no more such rises unless either interest rates or realized relative volatility change.[24] The model discussed here suggests that unless the inputs to the model change, any repricing of equities is approximately complete.

Finally, if the model is accurate, a belief that a near-term windfall profit of about three times your money is currently available in the broad stock market, a belief held by Glassman and Hassett, is dangerous. First, investors who believe in the windfall possibility may overallocate to stocks.[25] Second, short-term pricing errors induced by believers in this argument (or "bubbles") can be dangerous to the real economy. Third, and perhaps most worrisome, if the model presented and tested in this paper is correct, the belief that stocks stand to receive a one-time enormous windfall profit is not simply wrong, it is backward. The low stock yields of today are fully explained by the model, meaning that the forecast of short-term stock returns is about average.[26] Moreover, if the conclusion here is true that the best forecasting variable for long-term stock returns is the absolute level of stock yields, then today's low yields (both D/P and E/P) point to a poor forecast for the long-term return on stocks.

Conclusion

Each of the puzzles stated at the beginning of this article can be resolved by using the model provided in Equation 6 for the required yield on stocks. Consider the first question: Why did the stock market strongly outyield bonds for so long only to now consistently underyield bonds? The model states that (1) the higher bond yields are and (2) the higher perceived stock market volatility versus bond market volatility is, then the higher stock yields must be. For a long time (before the 1950s), stocks outyielded bonds because the realized volatility of stocks versus bonds was much higher than in modern times.

Consider the second question: Why did stock and bond yields move relatively independently, or even perversely, in the 1927–98 period but strongly move together in the later 40 years of this period? Stock and bond yields appear to move independently or even perversely over long periods (e.g., 1926–1998), but this appearance is an artifact of missing a part of their structural relationship. If the impact of changing volatility is taken into account, stock and bond yields are strongly positively correlated over the entire period for which we have data, which many strategists and economists would have hypothesized.

Finally, consider the third question: Why are today's stock market yields so low and what does that fact mean for the future? Today's stock market yields are so low simply because bond yields are low and recent realized stock market volatility has been low when compared with bond market volatility. I do not need to resort to "the world has changed" types of arguments to explain today's low yields. The model fully explains them. And the model indicates that they will not go much lower unless realized stock versus bond volatility or interest rates fall farther.

Although testing a long-term, slowly changing relationship has statistical difficulties, the model easily survived every reasonable robustness check, including out-of-sample testing of a previously untouched period (1871–1945) and the formation of completely nonoverlapping, nonserially correlated independent and dependent variables for the entire 1871–1998 period.

This work has strong theoretical implications. A link between volatility and expected return is one of the strongest implications of modern finance.[27] Researchers have found compelling evidence of this phenomenon in comparing asset classes (i.e., stocks versus bonds), but evidence of a link *within* asset classes (e.g., testing the capital asset pricing model for stocks) or an intertemporal link within one asset class has been weak. This article addresses the intertemporal link. Past studies failed to convincingly link expected stock returns to *ex ante* volatility through realized stock returns.[28] However, realized stock returns are very noisy. I hypothesized that D/P (or E/P) is a proxy for expected stock returns and that Y is a proxy for expected bond returns and found strong confirmation that the difference between these proxies is a positive function of differences in experienced volatility. In other words, unlike many other studies, I have documented a strong positive intertemporal relationship between expected return and perceived risk.

This article demonstrated that the relative long-term volatility experienced by investors is a strong driver of the relative yields they require on stocks versus bonds; it did *not* show that these long-term realized volatility figures are accurate forecasts of future volatility. Thus, I have clearly identified a behavioral relationship that I believe is important, but I offer no verdict on market efficiency.[29]

The bottom line is that today's stock market (as of May 1998) has very low yields (D/P and E/P) for the simple reason that bond yields are low and stock volatility has been low as compared with bond volatility. These conditions historically lead investors to accept a low yield (and expected return) on stocks. If one is a short-term investor, knowing that these low yields are not abnormal may be comforting. A long-term investor, however, might be very nervous, because raw stock yields (D/P and E/P) are the best predictors of long-term stock market returns and these raw yields are currently at very low levels.

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Notes

1. A set of assumptions sufficient for this equality to hold for coupon-bearing bonds is that the yield curve be flat and unchanging.
2. The sources and/or construction of the data for this article are as follows: For stocks, return and earnings yield data on the S&P 500 came from Datastream and dividend yields from Ibbotson Associates. For bonds, return data for January 1980 to May 1998 are from the J.P. Morgan Government Bond Index levered to a constant duration of 7.0 (i.e., the monthly return used is the T-bill rate plus 7.0 divided by the beginning-of-the-month J.P. Morgan duration times the return on the J.P. Morgan index minus the T-bill return). I constructed a constant-duration bond in the hopes of making my bond return series more homoscedastic. The choice of a duration of 7.0 was arbitrary and had no effect on the results. I performed the regression of this excess return series on the excess monthly return of the Ibbotson Associates long- and intermediate-term bond series for January 1980 to May 1998. For January 1926 to December 1979, I used the fitted values on the Ibbotson return series to approximate the 7.0-year duration J.P. Morgan government bond series. For bond yields, I used the 10-year benchmark yield from Datastream from January 1980 to May 1998. For January 1926 to December 1979, I used the fitted multiple regression forecast (fitted from the regression over the January 1980–May 1998 period) of the 10-year yield on the Ibbotson

short-, intermediate-, and long-term government bond series. The results are not sensitive to precise definitions of the bond yield or return.

3. The earnings yield I used is prior year's earnings over current price. All the economic results in this article are robust to using either a 3- or 10-year moving average of real earnings in the numerator.
4. Equation 3 almost assuredly should be augmented with variables proxying time-varying expected dividend growth (see Fama and French 1988). I have tested such proxies and found them to be statistically significant, but I omitted them from this article because they affect none of the results or conclusions significantly.
5. Bernstein (1993, 1997) examined a related (although slightly different) model and came to some of the same conclusions.
6. The results presented here were insensitive to assuming other reasonable functional forms for this relationship (for example, assuming linearity in the log of the volatilities rather than the levels).
7. Kane, Marcus, and Noh (1996) examined a related model for the first difference of market P/Es (a somewhat different exercise) and came to some conclusions similar to mine.
8. These studies used forms similar to Equation 5.
9. Another logical extension of Equations 3, 4, and 5 is $Y = c + e$T-bill $+ d\sigma$(Bonds). That is, the yield on bonds moves (possibly at a multiple) with the short-term interest rate, and this weighted difference between long-term and short-term yields is a positive function of perceived bond volatility. Although not the focus of this article (but the focus of a future paper), empirical tests of this equation strongly support this specification.
10. This work is not sensitive to the definition of generation as precisely 20 years.
11. Note that I am not attempting to use the best short-term conditional estimate of volatility. Short-term changes in volatility may be mostly transitory. If so, they would have little impact on stock prices and required stock yields (see, for instance, Poterba and Summers 1986).
12. All R^2 values were adjusted for degrees of freedom.
13. Granger and Newbold (1974) found that in regressions of one random walk on another, rejection of the null hypothesis is more the rule than the exception. Also see Kirby (1997) or Goetzmann and Jorion (1993).
14. As mentioned previously, the results of this article are not very sensitive to the choice of a 20-year window for volatility. For instance, using a 10-year window for volatility estimation greatly reduced (but did not eliminate) the degree of autocorrelation in the right-hand variables. When I reestimate Equation 9 using 10-year rolling volatility (which also added 10 more years, 1936–1945, to the regression), the t-statistics did not materially change; the t-statistics on Y, σ(Stocks), and σ(Bonds) were, respectively, +10.00, +14.45, and –14.75. Using a 7-year window (now adding data from 1933–1945 to the regression), the t-statistics were +5.21, +11.54, and –10.93. A later section addresses this issue more directly by using longer-term data and analyzing nonoverlapping 20-year periods.
15. The sources for these data are Robert J. Shiller's Web page (an update of the data in Chapter 26 of Shiller 1989) and the company Global Financial Data.
16. These ratios are somewhat higher than reported in Figure 5 because the duration of the bond used in these annual tests was, on average, somewhat shorter than the duration of 7.0 years used in the monthly tests. Thus, bond volatility is somewhat lower in these annual tests. This change is only a matter of scale and has no economic effect on the tests.
17. For instance, Fama and French (1988) found that the parameters of the Lintner (1956) model for explaining dividend changes changed radically during the 1927–86 period.
18. As a final check, I reestimated Equation 24 using the Cochrane–Orcutt procedure to adjust for first-order auto-

correlation in the residuals. Each coefficient was essentially the same and remained statistically significant, whereas the first-order annual residual autocorrelation was highly statistically significant at 0.55.

19. This low autocorrelation matches the results of Poterba and Summers, who found only very short-term persistence in market volatility. Interestingly, I found that long-term rolling estimates of volatility seem to be crucial in determining the required expected return on the market but do not forecast the next period of long-term volatility itself. Thus, although investor perceptions of volatility drive market expected returns, those perceptions have not necessarily been accurate. My model might correctly describe investor behavior, but reconciling this behavior with market efficiency may be difficult (although not necessarily impossible). I leave this endeavor to future work.
20. In fact, the failure of the one regression (1895–1995) was driven by the 1975 observation (without this observation, the regression had an R^2 of 89.5 percent and a t-statistic of +5.93). Furthermore, by the luck of the draw, this regression did not include values for either the x or y variable as extreme as in Figures 7 and 8, which lowered the power of this test.
21. These regression results should not be considered an accurate test of a short- or long-term trading strategy. First, the regressions used D/P, which because it has price in the denominator, is known to induce a small bias toward finding a positive coefficient. The regressions also used the full-period data to form D/P(Error), which would not have been known prior to the end of the period. Finally, of course, the regressions do not account for trading costs. These regressions are meant to be indicative of the forecasting power of the model versus traditional models. Formal tests of a trading strategy based on these methods are not available from the author; trying to profit from such strategies is what I do for a day job.
22. These tests were carried out on in-sample regression residuals to retain the full 1946–98 period. Analogous significant results (although a bit weaker) were found for 1966–1998 when rolling out-of-sample versions of D/P(Fit) and D/P(Error) were used.
23. Two good sources for a scholarly but readable review of these issues are Siegel (1994) and Cornell (1999).
24. Glassman and Hassett did offer some reasons why stock volatility might be lower in the future than in the past, but their central argument does not need this farther drop to happen because their argument is that stocks are no more risky than bonds right now.
25. In all fairness, the actual practical investment advice in the book *Dow 36,000* appears quite reasonable, although it is still easy to see how an investor who believes in the authors' premise will not act so reasonably.
26. When this article was written, May 1998 data were the latest used. As of November 1999, the model's short-term forecast for stocks had joined the long-term forecast of stocks as below average, although not nearly as severely below average as the long-term forecast. I would be happy to provide a more up-to-date forecast and can be contacted at cliff.asness@aqrcapital.com. Of course, trade on such a forecast at your own risk!
27. This link does not need to hold precisely for inefficient portfolios.
28. An exception is Kane, Marcus, and Noh, who correctly pointed out that this relationship is much clearer in *ex ante* measures than in *ex post* returns.
29. Unfortunately, I also could not determine the rationality of the predictive power of D/P(Error) over short horizons and D/P(Fit) over long horizons. Modigliani and Cohn (1979) argued that when inflation (and presumably bond yields) is low, investors mistakenly (i.e., irrationally or inefficiently) overprice equities (and vice versa). The empirical results of this study support their hypothesis in one way: When volatility is held constant, investors do price stocks at higher P/Es and P/Ds when interest rates are low (and vice versa). This empirical finding is an important contribution, because more-naive tests (which fail to account for relative volatility changes) do not pick up this relationship. However, distinguishing whether the short-term predictive power of D/P(Error) or the long-term predictive power of D/P(Fit) is coming from such mispricing or rational variance in expected return (perhaps caused by changing risk aversion) is beyond the scope of this article.

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Cash Flow Risk, Discounting Risk, and the Equity Premium Puzzle

Gurdip Bakshi and Zhiwu Chen*

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*Bakshi is at Department of Finance, Smith School of Business, University of Maryland, College Park, MD 20742, Tel: (301) 405-2261, email: gbakshi@rhsmith.umd.edu, and Website: www.rhsmith.umd.edu/finance/gbakshi/; and Chen at Yale School of Management, 135 Prospect Street, New Haven, CT 06520, Tel: (203) 432-5948, email: zhiwu.chen@yale.edu and www.som.yale.edu/faculty/zc25. The earnings data used in the paper are provided to us by I/B/E/S International Inc. We thank our colleagues Doron Avramov, Charles Cao, Steve Heston, Nengjiu Ju, Mark Loewenstein, Dilip Madan, and Harry Mamaysky for many constructive discussions on this topic. This article is being prepared for the *Handbook of Investments: Equity Premium*, edited by Rajnish Mehra. We are grateful to Rajnish Mehra for inviting us to contribute this chapter. The paper has improved from the feedback of Rajnish Mehra and two anonymous referees. We welcome comments, including references to related papers we have inadvertently overlooked. The computer codes used to implement the model are available from either of the authors.

Cash Flow Risk, Discounting Risk, and the Equity Premium Puzzle

Abstract

This article investigates the impact of cash flow risk and discounting risk on the aggregate equity premium. Our approach is based on the idea that consumption is hard to measure empirically, so if we substitute out an empirically difficult-to-estimate marginal utility by a pricing kernel of observables, we can evaluate the empirical performance of an equilibrium asset pricing model in a different way. Once the pricing-kernel process is specified, we can endogenously solve for the equity premium, the price of the market-portfolio and the term structure of interest rates within the same underlying equilibrium. Embedded in the closed-form solution are compensations for cash flow risk and discounting risk. With the solution for the risk premium explicitly given, we then calibrate the model to evaluate its empirical performance. This approach allows us to avoid the impact of the unobservable consumption or market portfolio on inferences regarding the model's performance. Our illustrative model is based on the assumption that aggregate dividend equals a fixed fraction of aggregate earnings plus noise, and the expected aggregate earnings growth follows a mean-reverting stochastic process. Moreover, the economy-wide pricing kernel is chosen to be consistent with (i) a constant market price of aggregate risk and (ii) a mean-reverting interest rate process with constant volatility. Estimation results show that the framework can mimic the observed market equity premium.

1 Introduction

In their seminal contribution, Mehra and Prescott (1985) show that the observed equity premium on the S&P 500 market index is far too high given the stochastic properties of aggregate consumption and under plausible assumptions about risk aversion. Furthermore, equity returns empirically covary little with aggregate consumption growth, implying also that the average equity premium can only be reconciled through an implausibly large coefficient of relative risk aversion. Table 1 in Mehra and Prescott (2003) documents that the average equity premium in the U.S. is 6.92%, while the real rate of interest is 1.14%, over the sample period of 1889-2000. Why have stocks delivered an average return of about 7% over risk-free bonds? Why is the observed real rate on Treasuries so low? Why is the systematic risk, as exemplified by the correlation between consumption growth and market-index return, so small?

Collectively known as the equity premium puzzle, this set of questions has consumed financial economists over the past two decades and generated competing explanations ranging from (i) generalizations to state-dependent utility functions (Constantanides (1990), Epstein and Zin (1991), Benartzi and Thaler (1995), Bakshi and Chen (1996), Campbell and Cochrane (1999), and Barberis, Huang, and Santos (2001)); (ii) the fear of catastrophic consumption drops (Reitz (1988)); (iii) the presence of uninsurable and idiosyncratic income risk (Heaton and Lucas (1996) and Mankiw (1986)); (iv) borrowing constraints (Constantinides, Donaldson, and Mehra (2002)); and (v) measurement errors and poor consumption growth proxies (Breeden, Gibbons, and Litzenberger (1989), Mankiw and Zeldes (1991), Ferson and Harvey (1992), and Aït-Sahalia, Parker, and Yogo (2004)). Despite the substantial research efforts, there is controversy whether these explanations can completely explain all aspects of the equity premium puzzle (Mehra and Prescott (2003)), and the original puzzle remains unsolved. That is, under plausible parameterizations, existing models can only generate a small equity premium.

This article expounds on a risk-based explanation without taking a stand on the precise parametric specification of the marginal utility function. Our approach is based on the idea that consumption is hard to measure empirically, so if we substitute out an empirically difficult-to-estimate marginal utility by a pricing-kernel function of observables we can evaluate the empirical performance of an equilibrium asset pricing model in a different way. That is, once the pricing-kernel process is specified, we can endogenously solve for the equity premium, the current price of the market portfolio and the term structure of interest rates within the same underlying equilibrium. Embedded in the closed-form solutions are compensations for cash flow risk and discounting risk. With these solutions for the risk premium, we can then calibrate the model to evaluate its empirical performance. This approach allows us to avoid the impact of unobservable consumption on inferences regarding an asset pricing model's performance.

We illustrate the potential of this modeling approach by using some simple assumptions. First, we posit that a fixed proportion of the market-portfolio earnings (plus some noise) will be paid out as dividends. This assumption allows us to directly link the stock price and the equity premium to the firm's earnings, instead of dividends. This modeling feature is important because dividend-based stock valuation models have not succeeded empirically, and investors are far more interested in the earnings of a stock rather than its dividends. Second, we assume some marginal utility function that is consistent with both a constant market price of aggregate risk and a single-factor Vasicek (1977) term structure of interest rates. It is further assumed that the market-portfolio earnings-per-share (EPS) obeys a proportional stochastic process, with its expected growth rate following a mean-reverting process (under the physical probability measure). Thus, in our equity valuation setting, there is an embedded stochastic term structure of interest rates, the expected EPS growth follows a stochastic process, the current market-index level depends on earnings (instead of dividends), and both cash flow risk and interest rate risk are priced. The rationale for our assumptions will be discussed in more details shortly.

It is shown that risk aversion implicit in the pricing kernel introduces a wedge between the physical process and the risk-neutralized process of variables in the economy. Specifically, the working of risk aversion makes the risk-neutral drift of the interest rate process higher than its physical counterpart and leads to a heavier discounting of stochastic cash flow streams. This mechanism generates lower market valuations and a higher equity premium (even though this effect also raises bond yields).

Risk aversion also affects the risk-neutralized cash flow process: the risk-neutral drifts for both the earnings and the expected earnings growth processes are lower than their counterpart under the physical probability measure. Such a mapping is suggestive of a positive compensation for both earnings risk and expected earnings-growth risk. Overall, the equity premium is a weighted sum of compensations for risks associated with interest rate, earnings, and expected earnings-growth shocks, with the weights dependent on the state-of-the economy and the structural parameters.

Our empirical implementation provides several insights on how discounting risk and cash flow risks are reflected and simultaneously priced in the S&P 500 index and default-free bonds. We find that the interest-rate risk premium is negative and it contributes to a 77.16 basis-point spread between the market-portfolio and the risk-free interest rate. Moreover, the compensation for expected earnings-growth risk is negligible, and the compensation for earnings risk is 6.53%. It is the risk premium for earnings uncertainty, and not expected earnings-growth uncertainty, that largely drives the equity premium. The total model-derived equity premium is 7.31% and quantitatively robust under perturbations to test design methods. Overall, our empirical exercise demonstrates that the signs of the risk premiums are consistent with economic theory and show promise in explaining the behavior of the average equity premium and the Treasury yield curve. We argue that replacing the marginal utility by a pricing-kernel function of observables, and sensibly parameterizing the discounting structure and cash flows, is crucial to achieving a reasonable equity premium and improved performance.

The purpose of this article is not to test whether a particularly parameterized economic model would be able to explain the observed equity premium under some reasonable set of parameter values. Rather, the goal is to show that given the unobservability of key economic variables (such as consumption and the market portfolio), an alternative approach to testing an economic model is to rely on its internal equilibrium relations to substitute out unobservable variables by functions of observable financial market variables. Then, a test on the resulting equilibrium relations amounts to a test on the economic model itself. Perhaps, another way to look at the results in this article is that it shows what basic properties an empirically successful pricing kernel must have in order to be consistent with the observed equity premium in the U.S. stock market.

In what follows, Section 2 outlines assumptions and develops analytical expressions for the price of the market portfolio and the equity premium. Section 3 describes the data on S&P 500 earnings, equity premium, interest rates, and the panel of bond prices. Section 4 estimates the valuation model and discusses its implication for the equity premium. Concluding statements are provided in Section 5. The mathematical derivations for the price of the market portfolio and the equity premium are provided in the Appendix.

2 Economic Determinants of Equity Premium

This section develops a framework to study the determinants of the time-t price of the market-portfolio, P_t, for each time $t \geq 0$, and the instantaneous market-index risk premium $\mu_t - r_t$, for short interest rate r_t.

Consider a continuous-time, infinite-horizon economy whose underlying valuation standard is represented by some pricing-kernel process, denoted by M_t. Assume that the market-portfolio entitles its holder to an infinite dividend stream $\{D_t : t \geq 0\}$. Asset pricing models under the perfect-markets assumption implies

$$P_t = \int_t^\infty E_t\left[\frac{M_u}{M_t} D_u\right] du, \qquad \text{and,} \tag{1}$$

$$\mu_t - r_t = -\mathrm{Cov}_t\left(\frac{dM_t}{M_t}, \frac{dP_t}{P_t}\right)/dt, \tag{2}$$

where $E_t[\cdot]$ is the time-t conditional expectation operator with respect to the objective probability measure. All variables in (1)-(2) are in nominal terms. In this framework, the instantaneous equity premium and the price of the market-portfolio are determined endogenously and jointly within the same underlying risk-return equilibrium. The basic model outlined below is adopted from Bakshi and Chen (2005).

2.1 Cash Flow Process

To explicitly solve (1)-(2), assume that the market-portfolio has a constant dividend-payout ratio (plus noise), α (with $1 \geq \alpha \geq 0$), that is,

$$D_t\, dt = \alpha\, Y_t\, dt + d\, Z_t, \tag{3}$$

where Y_t is the aggregate earnings-per-share (EPS) flow at t and hence $Y_t\, dt$ is the total EPS over the interval from t to $t + dt$, and $d\, Z_t$ is the increment to a martingale process with zero mean. The existence of $d\, Z_t$ allows the market-portfolio dividends to randomly deviate from the fixed proportion of its EPS, and it makes D_t and Y_t not perfectly substitutable. Although this temporary deviation could be correlated with recent earnings and past deviations, incorporating this feature, or the stochastic pay-out ratio feature, into the assumption would unnecessarily complicate the model (see Lintner (1956), Marsh and

Merton (1987), Barsky and Delong (1993), and Menzly, Santos, and Venonesi (2004)).

Under the objective probability measure, Y_t is assumed to follow a process given below:

$$\frac{dY_t}{Y_t} = G_t\,dt + \sigma_y\,dW_t^y, \tag{4}$$

$$d\,G_t = \kappa_g\left(\mu_g^* - G_t\right)\,dt + \sigma_g\,dW_t^g, \tag{5}$$

for constants σ_y, κ_g, μ_g^* and σ_g. The long-run mean for both G_t and actual EPS growth $\frac{dY_t}{Y_t}$ is μ_g^*, and the speed at which G_t adjusts to μ_g^* is reflected by κ_g. Further, $\frac{1}{\kappa_g}$ measures the duration of the firm's business growth cycle. Volatility for both earnings growth and changes in G_t is time-invariant.

The cash flow process parameterized in (4) offers enough flexibility to model the level of the market-portfolio and the instantaneous equity premium (see also Bakshi and Chen (1997) and Longstaff and Piazzesi (2004)). First, both actual and expected earnings growth can take either positive or negative values, reflecting business cycles. Second, expected EPS growth G_t is mean-reverting and has both a permanent component (reflected by μ_g^*) and a transitory component, so that G_t can be high or low relative to its long-run mean μ_g^*. Finally, since Y_t is observable and G_t can be obtained from analyst estimates, we can learn about the equity premium based on readily identifiable and observable state variables.

2.2 The Discounting Process

Turning to the pricing kernel, assume, as in Constantinides (1992), that M_t follows an Ito process satisfying

$$\frac{dM_t}{M_t} = -r_t\,dt - \sigma_m\,dW_t^m, \tag{6}$$

for a constant σ_m, where the instantaneous discounting rate, r_t, follows the Ornstein-Uhlenbeck mean-reverting process:

$$d\,r_t = \kappa_r\left(\mu_r^* - r_t\right)\,dt + \sigma_r\,dW_t^r, \tag{7}$$

for constants κ_r, μ_r^* and σ_r. The pricing kernel can be interpreted in the context of the consumption-based asset pricing model. Suppose $M_t = C_t^{-\gamma}$ for coefficient of relative risk aversion γ and aggregate consumption C_t, then Ito's lemma impies $\frac{dM_t}{M_t} = -\gamma\frac{dC_t}{C_t} + \frac{1}{2}\gamma(1+\gamma)\left(\frac{dC_t}{C_t}\right)^2$. Thus, we can write risk-return equation (2) as $\mu_t - r_t = \gamma\,\mathrm{Cov}_t\left(\frac{dC_t}{C_t}, \frac{dP_t}{P_t}\right)/dt$, and the equilibrium $r_t\,dt = \gamma\,E_t\left(\frac{dC_t}{C_t}\right) - \frac{1}{2}(\gamma)(1+\gamma)\,E_t\left(\frac{dC_t}{C_t}\right)^2$. Thus, unlike the traditional approaches in Mehra and Prescott (1985) and Weil (1989), we independently model the interest rate dynamics as specified in (7).

Parameter κ_r measures the speed at which r_t adjusts to its long-run mean μ_r^*. The pricing kernel (6) leads to a single-factor Vasicek (1977) term structure of interest rates, that is, the τ-period bond-price is: $B(t,\tau) = \exp\left(-\xi[\tau] - \varsigma[\tau]r_t\right)$, where $\varsigma[\tau] \equiv \frac{1-e^{-k_r\,\tau}}{k_r}$, and $\xi(\tau) \equiv -\frac{1}{2}\,\sigma_r^2 \int_0^\tau \varsigma^2[u]\,du + \left(\kappa_r\,\mu_r + \mathrm{Cov}_t\left(\frac{dM_t}{M_t}, dr_t\right)\right)\int_0^\tau \varsigma[u]\,du$. This approach provides interest rate parameters that can be separately calibrated to the observed Treasury yield curve.

Notice that shocks to expected growth, W^g, may be correlated with both systematic shocks W^m and interest rate shocks W^r, with their respective correlation coefficients denoted by $\rho_{g,m}$ and $\rho_{g,r}$. In addition, the correlations of W^y with W^g, W^m and W^r are respectively denoted by $\rho_{g,y}$, $\rho_{m,y}$ and $\rho_{r,y}$. Thus, both actual and expected EPS growth shocks are priced risk factors. The noise process dZ_t in (3) is however assumed to be uncorrelated with G_t, M_t, r_t and Y_t, and hence it is not a priced risk factor.

2.3 Dynamics of the Market-Portfolio

Substituting assumptions (3)-(7) into (1)-(2), we can see that the conditional expectations in P_t must be a function of G_t, r_t and Y_t. Applying Ito's lemma to P_t and substituting the resulting expression into risk-return equation (2), we have the partial differential equation (PDE) for P_t (the details are given in the Appendix):

$$\begin{aligned}
&\frac{1}{2}\,\sigma_y^2\,Y^2\,\frac{\partial^2 P}{\partial Y^2} + (G - \Pi_y)\,Y\,\frac{\partial P}{\partial Y} + \rho_{g,y}\sigma_y\sigma_g\,Y\,\frac{\partial^2 P}{\partial Y\partial G} + \rho_{r,y}\sigma_y\sigma_r\,Y\,\frac{\partial^2 P}{\partial Y\partial r} + \\
&\rho_{g,r}\sigma_g\sigma_r\,\frac{\partial^2 P}{\partial G\partial r} + \frac{1}{2}\sigma_r^2\,\frac{\partial^2 P}{\partial r^2} + \kappa_r\,(\mu_r - r)\,\frac{\partial P}{\partial r} + \frac{1}{2}\sigma_g^2\frac{\partial^2 P}{\partial G^2} \\
&+\kappa_g\,(\mu_g - G)\,\frac{\partial P}{\partial G} - r\,P + \alpha\,Y = 0,
\end{aligned} \tag{8}$$

subject to the transversality condition $P_t < \infty$. The transversality condition states that the stock price stay bounded for all combinations of the parameters governing cash flows, discounting, and their risk premiums. In the valuation equation PDE (8) we set,

$$\mu_g \equiv \mu_g^* - \frac{\Pi_g}{\kappa_g}, \tag{9}$$

$$\mu_r \equiv \mu_r^* - \frac{\Pi_r}{\kappa_r}, \tag{10}$$

which are, respectively, the long-run means of G_t and r_t under the risk-neutral probability measure defined by the pricing kernel M_t. It can be shown that

$$\Pi_y \equiv -\mathrm{Cov}_t\left(\frac{dM_t}{M_t}, \frac{dY_t}{Y_t}\right)/dt, \tag{11}$$

$$\Pi_g \equiv -\mathrm{Cov}_t\left(\frac{dM_t}{M_t}, dG_t\right)/dt, \tag{12}$$

$$\Pi_r \equiv -\mathrm{Cov}_t\left(\frac{dM_t}{M_t}, dr_t\right)/dt, \tag{13}$$

are the risk premium for the earnings shocks, expected earnings growth, and interest rate, respectively. Conjecture that the solution to the PDE (8) is of the form:

$$P_t = \alpha\, Y_t \int_0^\infty \overline{p}[t,u;G,r]\, du, \tag{14}$$

where $\overline{p}[t,u;G,r]$ can be interpreted as the time-t price of a claim that pays \$1 at a future date $t+u$. Solving the resulting valuation equation and the associated Ricatti equations subject to the boundary condition that $\overline{p}[t+u,0] = 1$ yields,

$$\overline{p}[t,u;G,r] = \exp\left(\,\varphi[u] - \varrho[u]\, r_t + \vartheta[u]\, G_t\,\right), \tag{15}$$

where

$$\begin{aligned}
\varphi[u] \;\equiv\;& -\Pi_y\, u + \frac{1}{2}\frac{\sigma_r^2}{\kappa_r^2}\left(u + \frac{1-e^{-2\kappa_r u}}{2\kappa_r} - \frac{2(1-e^{-\kappa_r u})}{\kappa_r}\right) - \frac{\kappa_r\mu_r + \sigma_y\sigma_r\rho_{r,y}}{\kappa_r}\left(u - \frac{1-e^{-\kappa_r u}}{\kappa_r}\right)\\
&+\frac{1}{2}\frac{\sigma_g^2}{\kappa_g^2}\left(u + \frac{1-e^{-2\kappa_g u}}{2\kappa_g} - \frac{2}{\kappa_g}(1-e^{-\kappa_g u})\right) + \frac{\kappa_g\mu_g + \sigma_y\sigma_g\rho_{g,y}}{\kappa_g}\left(u - \frac{1-e^{-\kappa_g u}}{\kappa_g}\right)\\
&-\frac{\sigma_r\sigma_g\rho_{g,r}}{\kappa_r\kappa_g}\left(u - \frac{1}{\kappa_r}(1-e^{-\kappa_r u}) - \frac{1}{\kappa_g}(1-e^{-\kappa_g u}) + \frac{1-e^{-(\kappa_r+\kappa_g)u}}{\kappa_r+\kappa_g}\right),
\end{aligned} \tag{16}$$

$$\varrho[u] \equiv \frac{1-e^{-\kappa_r u}}{\kappa_r}, \tag{17}$$

$$\vartheta[u] \equiv \frac{1-e^{-\kappa_g u}}{\kappa_g}, \tag{18}$$

subject to the transversality condition that

$$\mu_r - \mu_g > \frac{\sigma_r^2}{2\,\kappa_r^2} - \frac{\sigma_r \sigma_y \rho_{r,y}}{\kappa_r} - \frac{\sigma_g \sigma_r \rho_{g,r}}{\kappa_g \kappa_r} - \Pi_y + \frac{\sigma_g^2}{2\kappa_g^2} + \frac{\sigma_g \sigma_y \rho_{g,y}}{\kappa_g}. \tag{19}$$

Thus, the model price for the market-portfolio or a stock is the summed value of a continuum of claims that each pay at a future time an amount respectively determined by the earnings process. The presence of an integral in (14) should not hamper the applicability of the model as the integral can be computed numerically.

The valuation formula in (14) is not as simple to comprehend as the Gordon dividend growth model. Realize that the Gordon model is a special case in which both G_t and r_t are constant over time: $G_t = g$ and $r_t = r$, for constants g and r. Consequently, both M_t and Y_t follow a geometric Brownian motion. In this case, we obtain $P_t = \frac{\alpha\, Y_t}{r + \Pi_y - g}$ provided $r + \Pi_y - g > 0$. In our economic setting, valuation is more complex as both discounting and cash flow forecasts have to be simultaneously assessed at the same time.

2.4 Dynamics of the Equity Premium

In deriving the valuation formula, we relied on a CAPM-like risk-return relation to arrive at the PDE in (8). In this sense, our model is consistent with and built upon developments in the risk-return literature. But, as seen, a risk-return equation alone is not sufficient to determine P_t since assumptions on the cash flow processes are also needed. Based on (2) and the pricing solution (14), we can show that the equity premium is,

$$\begin{aligned}
\mu_t - r_t &\equiv E_t\left(\frac{dP_t}{P_t}\right)/dt + \frac{\alpha\, Y_t}{P_t} - r_t, \\
&= -\mathrm{Cov}_t\left(\frac{dM_t}{M_t}, \frac{dP_t}{P_t}\right)/dt, \\
&= \Pi_y \frac{Y_t}{P_t}\frac{\partial P_t}{\partial Y_t} + \Pi_g \frac{1}{P_t}\frac{\partial P_t}{\partial G_t} + \Pi_r \frac{1}{P_t}\frac{\partial P_t}{\partial r_t}, &\quad (20)\\
&= \Pi_y + \Pi_g\left(\frac{\int_0^\infty \overline{p}[t,u;G,r] \times \vartheta[u]\,du}{\int_0^\infty \overline{p}[t,u;G,r]\,du}\right) - \Pi_r\left(\frac{\int_0^\infty \overline{p}[t,u;G,r] \times \varrho[u]\,du}{\int_0^\infty \overline{p}[t,u;G,r]\,du}\right), &\quad (21)
\end{aligned}$$

where $\overline{p}[t,u;G,r]$ is displayed in (15). Equation (20) shows that the equity premium is a weighted sum of the risk premiums for shocks respectively due to earnings, expected earnings growth, and interest rate, with weights equal to the sensitivity of the price with respect to the respective state-variables.

Equation (21) follows from (20) since $\frac{Y_t}{P_t}\frac{\partial P_t}{\partial Y_t} = 1$, $\frac{\partial P_t}{\partial G_t} = \alpha\, Y_t \int_0^\infty \overline{p}[t,u;G,r] \times \vartheta[u]\, du$, and $\frac{\partial P_t}{\partial r_t} = -\alpha\, Y_t \int_0^\infty \overline{p}[t,u;G,r] \times \varrho[u]\, du$. Thus, the equilibrium equity premium is a function of the time-t interest rate, the expected EPS growth, the firm's required risk premiums, and the structural parameters governing the cash flow and interest rate processes. According to (21), $\mu_t - r_t$ is independent of the current level of cash flows and is mean-reverting with the state of r_t and G_t.

The dynamics of the state-variables under the equivalent martingale measure, Q, can facilitate our understanding of the nature of risk compensation in this economy. Based on (8), we may write the stock price as,

$$P_t \;=\; \alpha \int_t^\infty E_t^Q \left(e^{-\int_t^u r_s\, ds}\, Y_u \right) du, \tag{22}$$

where the processes for (Y_t, G_t, r_t) under the Q-measure are:

$$\begin{aligned}
\frac{dY_t}{Y_t} &= (G_t - \Pi_y)\, dt + \sigma_y\, d\widetilde{W}_t^y, && (23)\\
d\,G_t &= \kappa_g \left([\mu_g^* - \Pi_g/\kappa_g] - G_t \right) dt + \sigma_g\, d\widetilde{W}_t^g, && (24)\\
d\,r_t &= \kappa_r \left([\mu_r^* - \Pi_r/\kappa_r] - r_t \right) dt + \sigma_r\, d\widetilde{W}_t^r. && (25)
\end{aligned}$$

Economically, risk-averse investors seek to discount future cash flows more heavily under the equivalent martingale measure. For instance, we should expect $\Pi_r < 0$, which makes the drift of the risk-neutral discounting process higher. Consistent with this effect, a higher long-run mean $\mu_r = \mu_r - \Pi_r/\kappa_r$ will simultaneously reduce the discount bond price and raise all Treasury yields. Thus, our decomposition in (20) shows that $\Pi_r < 0$ can be expected to increase the overall equity premium, because $\frac{\partial P_t}{\partial r_t} < 0$. There is evidence from bond markets that the interest rate risk premium is non-zero (see, for example, Duffee (2002)).

A similar risk-aversion-based reasoning suggests that investors tend to be less optimistic about future cash flows under the equivalent martingale measure than under the physical probability measure. Intuitively, we have $\Pi_y > 0$ and $\Pi_g > 0$: the presence of both risk premiums decreases the drift of the (Y_t, G_t) process. The working of both of these forces reduces the present value of future cash flows and, thus, elevates the market risk premium. Thus, the earnings risk premium Π_y, the expected earnings growth risk premium Π_g, and the discounting risk premium receive positive compensation and contribute separately to the total equity premium.

To explore the properties of equity premium derived in (21), we turn to a comparative statics exercise and study how it responds to any structural parameter. In this example, $\kappa_r = 0.23$, $\mu_r^* = 7.8\%$, $\sigma_r = 0.012$, $\kappa_g = 1.44$, $\mu_g^* = 0.10$, $\sigma_g = 0.089$, σ_y=0.20, $\rho_{g,r}$= -0.05, $\rho_{g,y} = 1$, and $\alpha = 0.50$. We fix the interest rate risk premium $\Pi_r = -0.002$, the expected earnings growth risk premium $\Pi_g = 0.002$, and the earnings risk premium Π_y=0.06. In all calculations $r_t = 5.68\%$ and $G_t = 7.48\%$ which are market observed values as of July 1998 and correspond to S&P 500 index level of 1174.

Our numerical exercise shows that the equity premium is increasing in both G_t and μ_g^*, but decreasing in both r_t and μ_r^*. Therefore, as expected, positive shocks to expected EPS growth tend to raise the equity premium, whereas positive shocks to interest rates depress it. However, the equity premium is much more sensitive to μ_g^* (μ_r^*) than to G_t (r_t). Intuitively, these comparative static results hold because current expected EPS growth G_t may have a transitory component, whereas a change in μ_g is permanent. Lastly, the model equity premium increases with EPS growth volatility σ_y, the volatility of expected EPS growth σ_g, and the volatility of the interest rate σ_r. Risks as measured by these parameters raise the required compensation to shareholders. Modeling the EPS and the expected EPS processes explicitly indeed allows us to see how they affect the equity premium.

3 Time-Series Data on S&P 500 EPS, EPS Growth, and the Interest Rate

For the remainder of the paper we choose the S&P 500 index as the proxy for the market-portfolio. To explore whether the model equity premium derived in (21) is close to the sample equity premium requires three data inputs: expected EPS growth G_t, interest rate r_t, current EPS Y_t, and the model parameters. For the S&P 500 index, I/B/E/S did not start collecting analyst EPS estimates until January 1982. Thus, our focus is on the sample period from January 1982 to July 1998. Pastor and Stambaugh (2001) detect structural shifts in the equity premium especially over the past two decades. According to Lettau, Ludvigson, and Watcher (2004), the market price-to-earnings ratio rose sharply over this period and have argued in favor of the declining ex-ante equity risk premium explanation.

I/B/E/S US History File contains mid-month observations on reported actual earnings-per-share and consensus analyst forecasts of future S&P 500 earnings, plus the contemporaneous price. In implementation, I/B/E/S consensus analyst estimate for current-year S&P 500 EPS (i.e., FY1) is taken to be the proxy for Y_t. In any given month, the FY1 estimate may contain actual quarterly EPS numbers for the passed quarters of the fiscal year, with the EPS numbers for the remaining quarters being consensus analyst forecasts. Because firms' earnings typically exhibit seasonalities, the total EPS over a fiscal year is a natural proxy for Y_t.

Analyst-expected EPS growth from the current (FY1) to the next fiscal-year (FY2) is the measure for G_t. This choice is reasonable since the year-over-year EPS growth has been the conventional calculation method in the industry. For instance, quarter-over-quarter and month-over-month (if available) EPS growth rates would not be better proxies for G_t, as they would be subject to seasonal biases in earnings and revenue.

Valuation formulas for the market index and the equity premium also depend on interest rate r_t, for which there is no established benchmark. Empirically, movements in the 30-year Treasury yield are much more closely followed by stock market participants than the short-term rate, as the long-term yields often co-move strongly with S&P 500 earnings-yields. To be consistent with theory, however, we use the 3-month Treasury yield or those implied by the Kalman-filter as candidates for r_t in estimation and calibration. The 30-year Treasury yield is used in a robustness exercise. The source of monthly 3-month interest-rate is DataStream International, Inc.

To infer the interest rate risk premium independent of the price observations on the market portfolio, we rely on a panel of Treasury yields. We choose Treasury securities with constant maturity of 6 months, 2 years, 5 years, and 10 years. The Treasury yields are gathered from the Federal Reserve Board.

Table 1 reveals that the average equity premium over the sample period is 8.76% and volatile. Although the average equity premium is somewhat higher than the 7% reported by Mehra and Prescott (1985, 2003), it is nonetheless of a similar order of magnitude. That the equity index provides a higher return relative to bonds is also a stylized feature over our shorter sample.

Forward price-to-earnings ratio (the current price divided by FY1 earnings) has a sample average of 15.10, with a minimum price-to-earnings ratio of 7.28 and a maximum is 26.47. As seen, the average expected EPS growth for the S&P 500 index is 10.13% and varies between 0.09% and 26.13%. The average 3-month nominal interest rate is 6.28% with a standard deviation of 2.44%.

4 Implications of the Model for Equity Premium

The purpose of this section is two-fold. First, we pursue a traditional risk-based explanation of the equity premium puzzle and present an estimation strategy aimed at recovering each of the three components of the equity premium in (21). That is, we estimate Π_r, Π_g, Π_y, along with other model parameters, and judge empirical performance accordingly. Second, we quantitatively assess whether the risk premium parameterizations, interest rate dynamics, and cash flow dynamics embedded in the valuation model are capable of generating a reasonably large equity premium. We conduct these tasks while simultaneously fitting the Treasury yield curve as close as possible. Hence, our approach circumvents the risk-free rate puzzle outlined in Weil (1989).

4.1 How Large is the Interest Rate Risk Premium?

We first address the sign and magnitude of the interest rate risk premium by using the Kalman filtering approach and a panel of Treasury bond yields. This approach (i) enables the estimation of the interest rate risk premium jointly with the parameters of the interest rate dynamics in (7) (i.e., κ_r, μ_r^*, and σ_r), and (ii) allows us to test whether the interest rate model is able to generate realistic yield curve movements.

To implement this estimation procedure, we note that the transition equation for the instantaneous interest rate, r_t, can be expressed as (e.g., Bergstrom (1984)):

$$r_t \;=\; \mu_r^* \, (1 - e^{-\kappa_r \Delta t}) + e^{-\kappa_r \Delta t} \, r_{t-1} \,+\, \eta_t, \tag{26}$$

where $E_{t-1}[\eta_t] = 0$ and $E_{t-1}[\eta_t^2] = \sigma_r^2 \Delta t$, and η_t is a serially uncorrelated disturbance term that is distributed normal.

Next, let $\Psi_t = (\Psi_{j,t}, ..., \Psi_{J,t})'$ be the month-t observed Treasury yields where J denotes the number of yields employed in the estimation. As is standard from Babbs and Nowman (1999) and Chen and Scott (2003), the measurement equation describing observed Treasury yields is:

$$\Psi_t \;=\; \mathcal{U}_t + \mathcal{V}_t\, r_t + \upsilon_t, \qquad\qquad t = 1, ..., T, \tag{27}$$

where $\mathcal{U}_t$ is an $N \times 1$ vector with i-th element $\frac{\xi[\tau_i]}{\tau_i}$, $\mathcal{V}_t$ is an $N \times 1$ vector with i-th element $\frac{\varsigma[\tau_i]}{\tau_i}$, and $\upsilon_t \sim \mathcal{N}(0, \mathcal{H}_t)$. The normality of υ_t and η_t allows us to implement a Kalman filter recursion based on the maximum-likelihood approach described in Harvey (1991).

For this maximum-likelihood estimation, we select Treasury yields with maturity of 6 months, 2 years, 5 years, and 10 years and display the estimation results in Table 2. Panel A of this table shows that the interest rate parameters are reasonable and the interest-rate risk premium is in line with economic theory.

Let us discuss these parameter estimates in turn. First, the long-run interest rate, μ_r^*, is estimated at 7.28% and of an order of magnitude similar to that reported in Babbs and Nowman (1999) and Chen and Scott (2003). Second, the estimated $\kappa_r = 0.2313$ implies a half-life of 2.99 years, and indicates slow mean-reversion of the interest rate process. Third, the reported volatility of interest rate changes, $\sigma_r = 1.28\%$, suggests a relatively stable interest rate process. Finally, the maximized log-likelihood value for the estimation is 1804.93, and the estimated parameters are several times larger than their standard errors, suggesting statistical significance.

The estimated interest-rate risk premium, Π_r is, as we previously postulated, negative with a point estimate of -0.00201 (i.e., -20 basis points) and a standard error of 0.0005. Although the estimate appears quantitatively small, it can drive a substantial wedge between the risk-neutral and the physical interest rate processes. To see this point more clearly, we compute $\mu_r = \mu_r^* - \Pi_r/\kappa_r = 8.154\%$, which has the effect of raising the risk-neutral interest-rate drift by 86.9 basis points (hereafter, bp). Intuitively the risk factor $\Pi_r < 0$ causes a heavier discounting of future cash flows and theoretically supports the presence of a positive equity premium as the partial derivative of P_t with respect to the interest rate is negative in (21). Bonds provide a hedge during periods of stock market declines, which justifies a negative interest-rate risk premium. We refer the reader to the related work of Buraschi and Jitsov (2005) on the inflation risk premium and Bakshi and Chen (1996b) on a general model of inflation and interest rates in a monetary economy.

Goodness-of-fit statistics assessed in Panel B of Table 2 reveal that the interest rate model provides reasonable fitting-errors as measured by actual minus model-implied yield.

Across the Treasury yield curve the median absolute errors for 6-month, 2-year, 5-year, and 10-year yields are 37bp, 25bp, 35bp and 50bp, respectively. In sum, the time-series on the cross section of bond yields provide the desired flexibility in estimating the interest-rate risk premiums and the interest-rate parameters. Although there is scope for improvement, the pricing kernel process can realistically mimic both the short and the long end of the yield curve through time.

4.2 Maximum-Likelihood Estimation of the (Physical) G_t Process

The unavailability of contingent claims written directly on the G_t process precludes a joint estimation of the expected EPS growth processes in (5) and (24). We propose a two-step procedure to estimate Π_g. First, we exploit the transition density function to estimate the structural parameters, $\Theta_g \equiv \{\kappa_g, \mu_g^*, \sigma_g\}$, of the G_t process in (5). Second, taking Θ_g as given, we estimate Π_g, along with other unknown parameters, based on the time-series of S&P 500 index (the criterion function is specified in Section 4.3), and consequently recover the risk-neutral G_t process in (24).

Let $\{G_t : 1, \ldots, T\}$ be the monthly time-series on expected earnings growth rate. The discrete equation corresponding to the G_t process in (5), is:

$$G_t = \mu_g^* + e^{-\kappa_g} \left(G_{t-1} - \mu_g^*\right) + \zeta_t \tag{28}$$

where ζ_t is Gaussian mean-zero and satisfies the condition $E(\zeta_t \zeta_u) = 0$ for $t \neq u$, and

$$E(\zeta_t^2) = \frac{\sigma_g^2}{2\,\kappa_g} \left(1 - e^{-\kappa_g}\right). \tag{29}$$

Guided by Nowman (1997), we construct the likelihood function as minus twice the logarithmic of the Gaussian likelihood function

$$\max_{\kappa_g, \mu_g^*, \sigma_g} \quad \sum_{t=1}^{T} \left(\log\left\{ \frac{\sigma_g^2}{2\,\kappa_g} \left(1 - e^{-\kappa_g}\right) \right\} + \frac{\left\{G_t - \mu_g^* - e^{-\kappa_g} \left(G_{t-1} - \mu_g^*\right)\right\}^2}{\left\{\frac{\sigma_g^2}{2\,\kappa_g} \left(1 - e^{-\kappa_g}\right)\right\}^2} \right). \tag{30}$$

Maximizing the log-likelihood function in (30) by the choice of Θ_g, we report the maximum-likelihood parameter estimates below (the standard errors are shown in parenthesis):

$$\kappa_g = 1.4401 \;\; (0.4411) \tag{31}$$
$$\mu_g^* = 0.1024 \;\; (0.0153) \tag{32}$$
$$\sigma_g = 0.0894 \;\; (0.0047) \tag{33}$$

with an average log-likelihood value of 2.29575.

Several observations are relevant to our analysis. First, the point-estimate of long-run expected earnings growth rate, μ_g^*, is 10.04% and close to the sample average documented in Table 1. Thus, analysts have been optimistic about S&P 500 index earnings growth. Second, the volatility of changes in the expected earnings-per-share growth, σ_g, is 8.94%, which is considerably more volatile than the interest rate counterpart. Finally, according to the κ_g estimates, the S&P 500 expected earnings growth rate is mean-reverting with a half-life, $\log(2)/\kappa_g$, of 6 months. The duration of the expected earnings growth rate cycle is, thus, much shorter than the interest rate cycle and roughly consistent with stylized business cycle findings. Realizations of the physical G_t process are devoid of any information about the pricing measure, so the risk premium for expected earnings growth rate cannot be recovered through this estimation step.

4.3 Compensation for Cash Flow Risk and the Equity Premium

To estimate the risk premium for expected EPS growth risk, Π_g, and the risk premium for actual EPS growth, Π_y, and assess their implications for the equity premium, we make several choices. First, to reduce the estimation burden, we preset $\rho_{g,y} = 1$, and $\rho \equiv \rho_{g,r} = \rho_{r,y}$. This assumption implies that the actual and expected EPS growth rates are subject to a common random shock in (4) and (5). Second, we set Θ_g and $\{\kappa_r, \mu_r^*, \sigma_r, \Pi_r\}$ to the values estimated in Section 4.2 and Table 2, respectively. Thus, we treat these parameter inputs as representing the true values. Substituting Θ_g and $\{\kappa_r, \mu_r^*, \sigma_r, \Pi_r\}$ into (14)-(19), we can see that 5 parameters:

$$\Theta \equiv \{\Pi_g, \Pi_y, \alpha, \sigma_y, \rho\}, \tag{34}$$

are still required to determine the price of the market portfolio, P_t, in (14).

Observe that the valuation model for the market portfolio does not constitute a set of moment restrictions on asset prices; rather, it is an exact restriction on the price of the market portfolio in relation to the contemporaneous EPS, the expected EPS growth, and the interest rate. For this reason, the generalized method of moments and related econometric techniques may not be applicable.

Following the lead in fixed-income and option pricing, Θ is estimated using the time-series of market prices. We follow two estimation methods, one correcting, and the other not correcting, for the serial correlation of the model errors. Focusing on the first method, define from (14), the model price-to-earnings ratio as:

$$\mathrm{pe}_t \;\equiv\; \frac{P_t}{Y_t} = \alpha \int_0^\infty \overline{p}[t,u;G,r]\,du, \tag{35}$$

and let $\widetilde{\mathrm{pe}}_t$ be the month-t observed price-to-earnings ratio. Our estimation procedure tries to find a Θ to solve,

$$\mathrm{RMSE} \equiv \min_{\Theta} \sqrt{\frac{1}{T}\sum_{t=1}^{T}\left(\alpha\int_0^\infty \overline{p}[t,u;G,r]\,du - \widetilde{\mathrm{pe}}_t\right)^2}, \tag{36}$$

subject to the transversality condition in (19). This estimation method seeks to minimize the sum of squared errors between each observed price-to-earnings ratio and the model-determined price-to-earnings ratio. The restriction in (19) ensures that P_t does not explode in each iteration of the minimization routine.

Fitting the price-to-earnings is desirable because P_t/Y_t serves as a normalized price that is comparable across time periods. If the purpose would be to fit the observed price levels as closely as possible, the estimation procedure would then favor the higher price observations. The criterion function in (36) fails to account for the serial correlation of the model pricing errors. However, when we assume a first-order autoregressive process for the model error, the resulting estimates are similar. Hence, we omit them and focus on the least-squares method in (36).

The optimized objective function value from (36), RMSE, is zero only if the obtained Θ estimate leads to a perfect fit of each market price-to-earnings by the model. In general, the average in-sample price-to-earnings pricing error will not be zero because the objective in (36) is to minimize the sum of squared errors, but not the average pricing errors.

In our estimation approach, the estimated risk premiums and parameters reflect the historical valuation standards applied to the S&P 500 index by the investors. Panel A of Table 3 reports the parameter estimates of Θ when the 3-month Treasury rate is used as the proxy for r_t. Consistent with how the market has priced the market-portfolio in the past, the market-implied ρ is negative with a ρ of -0.109. This mildly negative point estimate of ρ suggests that expected earnings growth rate is likely high when the interest rate is low, and vice-versa.

Another result worth emphasizing is that the dividend-payout ratio, α, is consistent with intuition: the estimated $\alpha = 0.41$ does not depart substantially from the historical average payout ratios of 44.29%. Table 3 also provides the estimate of $\sigma_y = 18.17\%$, with the conclusion that the cash flow process experiences high volatility.

One central observation from Table 3 is that the market-implied expected-EPS-growth risk premium, $\Pi_g = -0.145\%$, is surprisingly small relative to the market-implied earnings risk premium, $\Pi_y = 6.531\%$. For example, the reported Π_g, implies that the sample average of $\Pi_g \left(\frac{\int_0^\infty \overline{p}[t,u;G,r] \times \vartheta[u]\, du}{\int_0^\infty \overline{p}[t,u;G,r]\, du} \right)$ is only 1 bp. This finding indicates that accounting for the compensation for bearing expected-EPS-growth risk plays virtually no role in explaining the equity premium puzzle.

If we accept the premise that the market fairly prices the S&P 500 index and correctly reflects the market price of various risks, then our empirical findings have a straightforward interpretation: Risk-averse agents may deem it unnecessary to "double-penalize" the physical drift of (Y_t, G_t) process. This may occur since P_t is homogenous of degree 1 in Y_t and has a first-order impact on the stock price. Therefore, a large compensation in the form of Π_y may make it unnecessary to require compensation for G_t risk. To further explain our reasoning, define $\widetilde{G}_t \equiv G_t - \lambda_y$. Therefore, we may write (23) and (24) as: $\frac{dY_t}{Y_t} = \widetilde{G}_t\, dt + \sigma_y\, d\widetilde{W}_t^y$, where $d\,\widetilde{G}_t = \left(\kappa_g \mu_g^* - \Pi_g - \kappa_g \Pi_y - \kappa_g \widetilde{G}_t\right) dt + \sigma_g\, d\widetilde{W}_t^g$. Thus, the presence of Π_y reduces the level and drift of the $\widetilde{G}_t$ process.

With $\Pi_r = -0.002$, the sample average of $-\Pi_r \left(\frac{\int_0^\infty \overline{p}[t,u;G,r] \times \varrho[u]\, du}{\int_0^\infty \overline{p}[t,u;G,r]\, du} \right)$ is 77.16 bp. This suggests that accounting for discounting risk can help alleviate the equity premium puzzle.

Based on (21), the overall equity premium can, thus, be calculated as

$$
\begin{aligned}
\mu_t - r_t &= \Pi_y + \Pi_g \left(\frac{\int_0^\infty \overline{p}[t,u;G,r] \times \vartheta[u]\, du}{\int_0^\infty \overline{p}[t,u;G,r]\, du} \right) - \Pi_r \left(\frac{\int_0^\infty \overline{p}[t,u;G,r] \times \varrho[u]\, du}{\int_0^\infty \overline{p}[t,u;G,r]\, du} \right), \\
&= 6.53\% + 0.01\% + 0.7716\%,
\end{aligned}
$$

$$= \quad 7.31\%.$$

The ability of the model to generate an equity premium of 7.31% is in sharp contrast with the exercise in Mehra and Prescott (1985) that a standard representative agent model calibrated to the per-capita consumption data can generate at most a 0.40% equity premium. Thus, the proper parameterization of both the discounting structure and the cash flow process is key to improving performance by an asset pricing model and to achieving a reasonable equity premium. Our exercise in Panel B of Table 3 demonstrates that the equity premium is virtually insensitive to the choice of the interest rate in the estimation procedure in (36).

Another economic yardstick that can be applied is whether the estimated risk premiums and model parameters provide a "good enough" approximation of the market's implicit valuation process. In Table 3, we also present two percentage pricing-error measures, computed by dividing the market-to-model price difference by the market price: (i) the absolute percentage pricing error, and (ii) the mean percentage pricing error. The mean pricing error reflects the average pricing performance, while the absolute pricing error reflects the magnitude of the pricing errors as negative and positive errors do not cancel each other. According to the pricing-error measures, the model's fit is reasonable: the average mean pricing error is -7.22% with a standard deviation of 23.98%, and the absolute pricing error of the S&P 500's 18.30%. Given the negative sign of the average errors, the model price is on average higher than the market price.

In summary, the class of models examined here are not only consistent with the average equity premium and the term structure of interest rates, but also mimics the time-evolution of the S&P 500 index. The latter dimension imposes a stringent restriction on the validity of the pricing framework and differentiates this paper from other studies on the equity premium.

5 Concluding Remarks and Extensions

The equity premium puzzle advocated by Mehra and Prescott (1985) remains a fascinating problem awaiting new and novel answers. This paper investigated the impact of cash flow risk and discounting risk on the aggregate equity premium, the price of the market portfolio, and the default-free bond prices. Our theoretical approach is based on the observation that aggregate per-capita consumption is hard to measure empirically. Thus, if we can replace the empirically difficult-to-estimate marginal utility by a pricing-kernel function of observables and then specify both the primitive process for discounting and the exogenous cash flow stream, we will have an equilibrium asset pricing model based on observable state variables. Once this is done we can endogenously solve for the equity premium, the price of the market portfolio and the term structure of interest rates within the same underlying equilibrium.

Embedded in the closed-form solution for the market portfolio and the bond prices are compensations for cash flow risk and discounting risk. With the solution for the risk premium explicitly given, we can then estimate the model to evaluate its empirical performance. This approach allows us to avoid the impact of unobservable consumption on inferences regarding the model's performance. Our illustrative model is based on the assumption that aggregate dividend equals a fixed fraction of aggregate earnings plus noise, and the expected aggregate earnings growth follows a mean-reverting stochastic process. Moreover, the economy-wide pricing kernel is chosen to be consistent with (i) a constant market price of aggregate risk and (ii) a mean-reverting interest rate process with constant volatility.

S&P 500 index-based estimation results show that the framework is quantitatively useful in explaining the observed market equity premium. Specifically, we find that the interest rate risk premium is negative and the cash flow risk premium is positive. Overall, disentangling the equity premium into its cash flow and discounting components produces an economically meaningful equity premium of 7.31%.

Our empirical results suggest three possible avenues for theoretical research. First, one can introduce richer cash flow dynamics and interest rate dynamics that possess stochastic volatility. Having multi-dimensional structures for the state variables with priced volatility risks can lead to more realistic models for the market portfolio and the equity premium. Second, one can examine alternative risk premium specifications that allow for richer stochastic variation in the risk premiums. Third, the valuation model can be used to pin down the sources of market return predictability, as in Menzly, Santos, and Veronesi (2004).

The equity premium puzzle occupies a special place in the theory of finance and economics, and more progress is needed to understand the spread of equities over bonds. Determining the factors that drive the equity premium over time, and across countries, will likely remain an active research agenda.

Appendix

To derive the analytical solution to the market portfolio, we note from equations (1) and (3) that P_t solves,

$$P_t \;=\; \alpha \int_t^{\infty} E_t\left[\frac{M_u}{M_t} Y_u\right] du, \tag{37}$$

since dZ_t is uncorrelated with dM_t. We also require by the transversality condition that $P_t < \infty$ for all t, which is the condition that the price of the market portfolio remain bounded for all pricing kernel and cash flow processes.

Inserting the pricing kernel process (6) into (37) and using the earnings process (4)-(5), we note, by the Markov property, that P_t can only be a function of Y_t, r_t, and G_t. Write $P[Y_t, G_t, r_t]$, where the interest rate process is as specified in (7). Therefore, the dynamics of the market portfolio, by Ito's lemma, is given by:

$$\begin{aligned} dP_t \;=\; & \frac{1}{2}\frac{\partial^2 P}{\partial Y^2}(dY)^2 + \frac{\partial P}{\partial Y} dY + \frac{1}{2}\frac{\partial^2 P}{\partial G^2}(dG)^2 + \frac{\partial P}{\partial G} dG + \frac{1}{2}\frac{\partial^2 P}{\partial r^2}(dr)^2 + \frac{\partial P}{\partial r} dr \\ & + \frac{\partial^2 P}{\partial Y \partial G} dY\, dG + \frac{\partial^2 P}{\partial Y \partial r} dY\, dr + \frac{\partial^2 P}{\partial G \partial r} dr\, dG. \end{aligned} \tag{38}$$

Substituting (38) into (2) implies that the instantaneous equity premium is,

$$\begin{aligned} \mu_t - r_t \;&=\; -\mathrm{Cov}_t\left(\frac{dM_t}{M_t}, \frac{dP_t}{P_t}\right)/dt, \\ &=\; -\mathrm{Cov}_t\left(\frac{dM_t}{M_t}, \frac{1}{P_t}\frac{\partial P}{\partial Y} dY + \frac{1}{P_t}\frac{\partial P}{\partial G} dG + \frac{1}{P_t}\frac{\partial P}{\partial r} dr\right)/dt, \end{aligned} \tag{39}$$

where the instantaneous expected return is, $\mu_t = E_t\left[\frac{dP_t}{P_t}\right]/dt + \frac{\alpha Y_t}{P_t}$.

Relying on (38) and taking expectations, we may obtain,

$$\begin{aligned} E_t\left[\frac{dP_t}{P_t}\right] \;=\; & \frac{1}{2}\frac{1}{P_t}\frac{\partial^2 P}{\partial Y^2} E_t[dY^2] + \frac{1}{P_t}\frac{\partial P}{\partial Y} E_t[dY] + \frac{1}{2}\frac{1}{P_t}\frac{\partial^2 P}{\partial G^2} E_t[dG]^2 + \frac{1}{P_t}\frac{\partial P}{\partial G} E_t[dG] \\ & + \frac{1}{2}\frac{1}{P_t}\frac{\partial^2 P}{\partial r^2} E_t[dr^2] + \frac{1}{P_t}\frac{\partial P}{\partial r} E_t[dr] \\ & + \frac{1}{P_t}\frac{\partial^2 P}{\partial Y \partial G} E_t[dY\, dG] + \frac{1}{P_t}\frac{\partial^2 P}{\partial Y \partial r} E_t[dY\, dr] + \frac{1}{P_t}\frac{\partial^2 P}{\partial G \partial r} E_t[dr\, dG]. \end{aligned} \tag{40}$$

Combining the expressions in (39) and (40) and using the definition of the instantaneous expected rate of return, we have

$$
\begin{aligned}
& \frac{1}{2}\frac{\partial^2 P}{\partial Y^2}\,E_t[dY^2]+\frac{\partial P}{\partial Y}\,E_t[dY]+\frac{1}{2}\frac{\partial^2 P}{\partial G^2}\,E_t[dG]^2+\frac{\partial P}{\partial G}\,E_t[dG]+\frac{1}{2}\frac{\partial^2 P}{\partial r^2}\,E_t[dr^2] \\
& +\frac{\partial P}{\partial r}\,E_t[dr]+\frac{\partial^2 P}{\partial Y\partial G}E_t[dY\,dG]+\frac{\partial^2 P}{\partial Y\partial r}E_t[dY\,dr]+\frac{\partial^2 P}{\partial G\partial r}E_t[dr dG] \\
& -r\,P\,dt+\alpha\,Y\,dt \\
= \; & -\mathrm{Cov}_t\left(\frac{dM_t}{M_t},\frac{\partial P}{\partial Y}\,dY+\frac{\partial P}{\partial G}\,dG+\frac{\partial P}{\partial r}\,dr\right). \qquad (41)
\end{aligned}
$$

Based on (41), now define the risk premium for the earnings shocks, expected earnings growth, and interest rate, respectively, as:

$$
\begin{aligned}
\Pi_y &\equiv -\mathrm{Cov}_t\left(\frac{dM_t}{M_t},\frac{dY_t}{Y_t}\right)/dt, \\
\Pi_g &\equiv -\mathrm{Cov}_t\left(\frac{dM_t}{M_t},dG_t\right)/dt, \\
\Pi_r &\equiv -\mathrm{Cov}_t\left(\frac{dM_t}{M_t},dr_t\right)/dt.
\end{aligned}
$$

This immediately implies that,

$$
\begin{aligned}
& \frac{1}{2}\frac{\partial^2 P}{\partial Y^2}\,E_t[dY^2]+\frac{\partial P}{\partial Y}\,E_t[dY]+\frac{1}{2}\frac{\partial^2 P}{\partial G^2}\,E_t[dG]^2+\frac{\partial P}{\partial G}\,E_t[dG]+\frac{1}{2}\frac{\partial^2 P}{\partial r^2}\,E_t[dr^2] \\
& +\frac{\partial P}{\partial r}\,E_t[dr]+\frac{\partial^2 P}{\partial Y\partial G}E_t[dY\,dG]+\frac{\partial^2 P}{\partial Y\partial r}E_t[dY\,dr]+\frac{\partial^2 P}{\partial G\partial r}E_t[dr dG]-r\,P\,dt+\alpha\,Y\,dt \\
= \; & \frac{\partial P}{\partial Y}\,Y\,\Pi_y\,dt+\frac{\partial P}{\partial G}\,\Pi_g\,dt+\frac{\partial P}{\partial r}\,\Pi_r\,dt. \qquad (42)
\end{aligned}
$$

Simplifying this equation and using the dynamics for Y_t, G_t and r_t, leads to the following partial differential equation for P_t:

$$
\begin{aligned}
& \frac{1}{2}\,\sigma_y^2\,Y^2\,\frac{\partial^2 P}{\partial Y^2}+(G-\Pi_y)\,Y\,\frac{\partial P}{\partial Y}+\rho_{g,y}\sigma_y\sigma_g\,Y\,\frac{\partial^2 P}{\partial Y\partial G}+\rho_{r,y}\sigma_y\sigma_r\,Y\,\frac{\partial^2 P}{\partial Y\partial r}+ \\
& \rho_{g,r}\sigma_g\sigma_r\,\frac{\partial^2 P}{\partial G\partial r}+\frac{1}{2}\sigma_r^2\,\frac{\partial^2 P}{\partial r^2}+\kappa_r\,(\mu_r-r)\,\frac{\partial P}{\partial r}+\frac{1}{2}\sigma_g^2\frac{\partial^2 P}{\partial G^2} \\
& +\,\kappa_g\,(\mu_g-G)\,\frac{\partial P}{\partial G}-r\,P+\alpha\,Y=0, \qquad (43)
\end{aligned}
$$

and must be solved subject the restriction that $P_t<\infty$. In the valuation partial differential equation (43) we have set, $\mu_g = \mu_g^* - \frac{\Pi_g}{\kappa_g}$ and $\mu_r \equiv \mu_r^* - \frac{\Pi_r}{\kappa_r}$. Consider the following candidate solution,

$$P_t = \alpha \int_0^\infty \hat{p}[t, u; Y, G, r]\, du. \tag{44}$$

Clearly, $\hat{p}[t + u, 0; Y, G, r] = Y_{t+u}$. Thus, we have the partial differential equation for $\hat{p}[t, u; Y, G, r]$ as,

$$\begin{aligned}
&(G - \Pi_y)\, Y \frac{\partial \hat{p}}{\partial Y} + \rho_{g,y}\sigma_y\sigma_g\, Y \frac{\partial^2 \hat{p}}{\partial Y \partial G} + \rho_{r,y}\sigma_y\sigma_r\, Y \frac{\partial^2 \hat{p}}{\partial Y \partial r} + \\
&\rho_{g,r}\sigma_g\sigma_r \frac{\partial^2 \hat{p}}{\partial G \partial r} + \frac{1}{2}\sigma_r^2 \frac{\partial^2 \hat{p}}{\partial r^2} + \kappa_r\,(\mu_r - r)\frac{\partial \hat{p}}{\partial r} + \frac{1}{2}\sigma_g^2 \frac{\partial^2 \hat{p}}{\partial G^2} \\
&+ \kappa_g\,(\mu_g - G)\frac{\partial \hat{p}}{\partial G} - r\,\bar{p} - \frac{\partial \hat{p}}{\partial u} = 0.
\end{aligned} \tag{45}$$

Suppose $\hat{p}[t, u; G, r] = Y_t \exp\left(\varphi[u] - \varrho[u]\, r_t + \vartheta[u]\, G_t\right)$. Taking the required partial derivatives with respect to Y_t, G_t and r_t and solving the valuation equations lead to a set of ordinary differential equations. Solving the ordinary differential equations subject to the boundary conditions $\varphi[0] = 0$, $\varrho[0] = 0$ and $\vartheta[0] = 0$ yields (14)-(15). The transversality condition (19) ensures that the restriction $\varphi[0] = 0$ is satisfied. □

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Table 1: Equity Premium for S&P 500 Index (January 1982 to July 1998)

The sample period is January 1982 to July 1998 with 199 monthly observations. The expected earnings-per-share growth for S&P 500 index, G_t, is the consensus earnings-per-share forecast for FY2 divided by FY1, minus 1. The price-to-earnings ratio, P/E, is the current S&P 500 index level normalized by FY1 earnings-per-share. We report the average, the standard deviation, the maximum, and the minimum. The computation of the monthly equity premium is based on the 3-month interest rate. The earnings and price on S&P 500 is collected from I/B/E/S and the interest rates are from the Federal Reserve Board.

	Average	**Std.**	**Max.**	**Min.**
Price-to-Earnings Ratio	15.10	4.13	26.47	7.28
Expected Earnings Growth	10.13%	5.31%	26.13%	0.09%
Interest Rate	6.98%	2.13%	14.68%	5.68%
Monthly Equity Premium	0.0073	0.040	0.162	-0.200

Table 2: Interest Rate Risk Premium Based on Kalman Filtering Estimation

The reported parameters of the interest rate process and the interest rate risk premium are based on Kalman filtering. We specify the interest rate process under the physical probability measure as:

$$dr_t \quad = \quad (\kappa_r\,\mu_r - \kappa_r\,r_t\,)\,dt + \sigma_r\,dW_t^r,$$

and under the equivalent martingale measure as

$$dr_t \quad = \quad (\kappa_r\,\mu_r - \Pi_r - \kappa_r\,r_t\,)\,dt + \sigma_r\,d\widetilde{W}_t^r,$$

The estimation uses a monthly time-series of treasury yields with maturity of 6-months, 2-years, 5-years and 10-years. The asymptotic standard errors are in parenthesis, and based on the outer-product of the log-likelihood function. Maximized log-likelihood function is reported as Log-Lik. Panel B reports the median absolute pricing errors (in bp), and the root mean squared pricing errors (in bp).

Panel A: Parameter Estimates

Parameter	κ_r	σ_r	μ_r^*	Π_r	Log-Lik
r_t process	0.2313 (0.0135)	0.0128 (0.0008)	0.0728 (0.0022)	-0.0020 (0.0005)	1804.93

Panel B: Fitting Errors for Bonds

	6-months	**2-years**	**5-years**	**10-years**
Median Absolute Pricing Errors (bp)	37	25	35	50
Squared-root of Mean Squared Errors (bp)	48	33	44	59

Table 3: Estimation of Risk Premiums for Earnings Growth and Expected Earnings Growth Rate: Implications for Equity Premium

Estimation of the risk premiums is based on S&P 500 index observations from January 1982 to July 1998 (199 observations). We minimize the distance between the model price-to-earnings ratio and the market price-to-earnings ratio denoted by $\widetilde{\mathrm{pe}}_t$:

$$\mathrm{RMSE} \equiv \min_{\Theta} \sqrt{\frac{1}{T} \sum_{t=1}^{T} \left(\alpha \int_0^{\infty} \overline{p}[t,u;G,r]\, du - \widetilde{\mathrm{pe}}_t \right)^2},$$

subject to the transversality condition $\mu_r - \mu_g > \frac{\sigma_r^2}{2\,\kappa_r^2} + \frac{\sigma_g^2}{2\kappa_g^2} + \frac{\sigma_g \sigma_y \rho_{g,y}}{\kappa_g} - \frac{\sigma_r \sigma_y \rho_{r,y}}{\kappa_r} - \frac{\sigma_g \sigma_r \rho_{g,r}}{\kappa_g \kappa_r} - \Pi_y$. In this estimation $\kappa_r = 0.2313$, $\sigma_r = 0.0128$, $\mu_r^* = 0.0728$ and $\lambda_r = -0.00201$ which are based on the results in Table 2, and $\rho_{g,y} = 1$, and $\rho \equiv \rho_{g,r} = \rho_{r,y}$. Parameters governing the dynamics of the expected earnings growth rate are fixed to $\kappa_g = 1.4401$, $\mu_g^* = 0.1024$, and $\sigma_g = 0.089$. We compute the model error $\epsilon_t \equiv Y_t \left(\alpha \int_0^{\infty} \overline{p}[t,u;G,r]\, du - \widetilde{\mathrm{pe}}_t\right)$, and report the average pricing errors and the average absolute pricing errors. The standard deviations are shown as Std(.). Each month we compute the model equity premium as $\mu_t - r_t = \Pi_y + \Pi_g \left(\frac{\int_0^{\infty} \overline{p}[t,u;G,r] \times \vartheta[u]\, du}{\int_0^{\infty} \overline{p}[t,u;G,r]\, du} \right) - \Pi_r \left(\frac{\int_0^{\infty} \overline{p}[t,u;G,r] \times \varrho[u]\, du}{\int_0^{\infty} \overline{p}[t,u;G,r]\, du} \right)$, and report the sample average as Mean$(\mu_t - r_t)$, All calculations in Panel A are done using the 3-month treasury rate as a proxy for the interest rate, and repeated in Panel B using the 30-year treasury rate.

Panel A: Estimation Based on 3-Month Treasury Rate

Π_g	Π_y	α	σ_y	ρ	RMSE	Mean(ϵ_t) {Std(ϵ_t)}	Mean$(\lvert\epsilon_t\rvert)$ {Std$(\lvert\epsilon_t\rvert)$}	Mean$(\mu_t - r_t)$
0.001450	0.06531	0.4100	0.1817	-0.109	3.2293	-7.22% {23.98%}	18.30% {17.63}	7.312%

Panel B: Estimation Based on 30-Year Treasury Yield

Π_g	Π_y	α	σ_y	ρ	RMSE	Mean(ϵ_t) {Std(ϵ_t)}	Mean$(\lvert\epsilon_t\rvert)$ {Std$(\lvert\epsilon_t\rvert)$}	Mean$(\mu_t - r_t)$
0.001145	0.06379	0.4744	0.1513	-0.074	3.1351	-7.62% {23.66%}	19.05% {15.92}	7.213%

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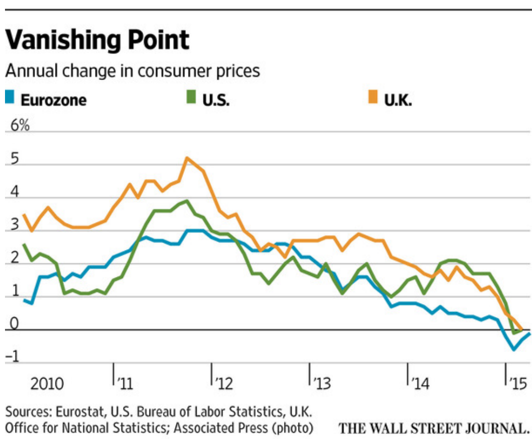
HEARD ON THE STREET

Zero Hour for Global Inflation

Persistently low inflation is making ultralow interest rates an abnormally normal situation



European Central Bank headquarters in Frankfurt

By RICHARD BARLEY

Updated April 6, 2015 9:13 p.m. ET

First it was interest rates. Now it is inflation.

Zero is becoming an uncomfortably familiar number. Unpicking the puzzle of ultralow inflation is vital for both policy makers and investors.

Even factoring in lower oil prices, the current readings are remarkable. Annual headline inflation in the U.S. was zero in February. Before its dip into negative territory during the global financial crisis, it had been positive since 1955. In the U.K., where even in 2009 inflation never fell below 1%, consumer prices were flat in February, year over year, for the first time since 1960. In Japan, inflation in February excluding food and taxes was zero. And in the eurozone, the flash reading for March shows consumer prices down 0.1% from a year earlier.

Inflation has fallen despite unprecedented monetary policy. Rates are close to zero and trillions of dollars' worth of quantitative easing has been unleashed. Ultralow inflation also stands at odds with falling unemployment. In Germany, for example, joblessness is at a record low since reunification, yet inflation stands at just 0.1%. Wage inflation has shifted into a lower gear from precrisis levels.

So far, however, markets and central bankers seem more worried than consumers. Extraordinarily low long-term bond yields paint a grim picture of the future; falling market measures of medium-term inflation have flustered central bankers, in particular at the European Central Bank. Even in the U.S., the five-year/five-year forward measure of inflation has fallen.

That is puzzling. The ECB might have a credibility problem in terms of its willingness to push inflation higher, given its Bundesbank heritage and rate increases in 2008 and 2011. But the Federal Reserve should have fewer problems: Indeed, there have been hints that inflation running above target for a while would be no problem. Still, markets appear worried.

Consumers seem less fazed. Surveys of European and U.S. consumers show stable inflation expectations over the medium term, even though they often extrapolate from current levels. Markets seem more guilty of that at present: The puzzling decline in U.S. inflation expectations is highly correlated with the fall in oil prices.

Markets may in fact be fretting more about central banks. With interest rates trapped close to zero, policy makers have little room left to maneuver against falling inflation; Japan's experience is a nagging reminder of that.

There may be a historical bias at work. Many view central banks such as the Fed as essentially institutions for fighting inflation rather than forces for stoking it. And a lot of current policy seems to be aimed at redistributing inflation through currency shifts. Central banks may also be facing pressures that are less amenable to domestic monetary-policy solutions, such as globalization and demographic shifts.

An important indicator now will be wage inflation, particularly in the U.S. and U.K. Job gains have put the so-called nonaccelerating inflation rate of unemployment, or NAIRU, in focus. This may be lower than in the past, due to structural changes in the labor market. But if unemployment falls further and wages remain subdued, central banks will face an even bigger inflation puzzle. In such an unusual situation, their reliance on extraordinary measures may become ever more ordinary.

Write to Richard Barley at richard.barley@wsj.com

Do Analysts Practice What They Preach and Should Investors Listen? Effects of Recent Regulations

Ran Barniv
College of Business Administration
Kent State University
rbarniv@kent.edu

Ole-Kristian Hope
Rotman School of Management
University of Toronto
okhope@rotman.utoronto.ca

Mark Myring
Miller College of Business
Ball State University
mmyring@bsu.edu

Wayne B. Thomas
Michael F. Price College of Business
University of Oklahoma
wthomas@ou.edu

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Do Analysts Practice What They Preach and Should Investors Listen?

Effects of Recent Regulations

ABSTRACT: From 1994 to 1998, Bradshaw (2004) finds that analysts' stock recommendations relate *negatively* to residual income valuation estimates but *positively* to valuation heuristics based on the price-to-earnings-to-growth ratio and long-term growth. These results are surprising, especially considering that future returns relate positively to residual income valuation estimates and negatively to heuristics. Using a large sample of analysts for the 1993-2005 period, we consider whether recent regulatory reforms affect this apparent inconsistent analyst behavior. Consistent with the intent of these reforms, we find that the negative relation between analysts' stock recommendations and residual income valuations is diminishing following regulations. We also show that residual income valuations, developed using analysts' earnings forecasts, relate more positively with future returns. However, we document that stock recommendations continue to relate negatively with future returns. We conclude that recent regulations have affected analysts' outputs – forecasted earnings and stock recommendations – but investors should be aware that factors other than identifying mispriced stocks continue to influence how analysts recommend stocks.

Keywords: Stock recommendations, residual income valuations, valuation heuristics, future returns, regulations.

Data Availability: All data are available from public sources.

I. INTRODUCTION

Using an extensive sample of sell-side financial analysts, we first examine how Regulation Fair Disclosure (Reg FD) and other recent regulatory reforms (e.g., NASD Rule 2711, NYSE Rule 472, and the Global Research Analysts Settlement) affect the relation between analysts' stock recommendations and (1) theoretically-derived residual income models versus (2) valuation heuristics based on the price-to-earnings to growth (PEG) ratios and long-term growth (LTG) forecasts. Our second set of tests involves one-year-ahead excess stock returns. We examine the impact of regulations on relation between future returns and (1) stock recommendations, (2) residual income models, and (3) valuation heuristics. Finally, we consider the extent to which residual income models and valuation heuristics are incremental to stock recommendations in explaining future returns after regulations are implemented.

This research is important because it speaks directly to an issue of great interest to investors and regulators: To what extent do regulations impact financial information provided by an important user group (i.e., financial analysts)? Given the widespread availability of financial analysts' earnings forecasts and stock recommendations, our results have practical importance to the investment community and regulators, as well as implications for academic research. While our first set of tests provides understanding of how analysts incorporate their own earnings forecasts into their stock recommendations, our tests of future returns have direct importance to investors. Furthermore, given the historical problems associated with stock recommendations, the extent to which valuation estimates (based on analysts' earnings forecasts) provide explanatory power beyond stock recommendations for future returns will be particularly important to investors.[1]

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[1] We do not suggest that all investors use both analysts' earnings forecasts and stock recommendations when making investment decisions. Sophisticated investors may use analysts' earnings forecasts and ignore their stock

Presumably, analysts use their own publicly issued earnings forecasts to derive intrinsic value estimates. In this case, one should expect these estimates to relate to analysts' stock recommendations (e.g., Schipper 1991). When earnings-based intrinsic value estimates are above (below) the current stock price, analysts would issue a buy (sell) recommendation. If instead, analysts' recommendations are based on other factors (beyond sophisticated earnings-based valuation estimates), then valuation estimates may provide incremental explanatory power beyond recommendations for future stock performance.

In an interesting recent study, Bradshaw (2004) uses a sample of U.S. firms from 1994 to 1998 and finds that residual income valuations, developed using analysts' earnings forecasts, do not relate as expected with analysts' recommendations. Analysts give more favorable recommendations to stocks with lower residual income valuations relative to current price.[2] Instead, analysts' recommendations align more closely with their LTG forecasts and the PEG ratio. These findings suggest that analysts give the highest recommendations to growth stocks, and among growth stocks, they give the highest recommendations to the firms for which the value of growth estimated by the PEG model exceeds the current stock price. Bradshaw (2004) concludes that analysts rely on simple heuristics rather than more sophisticated residual income valuations to recommend stocks.[3]

Bradshaw (2004) also finds that residual income valuations, developed using analysts' earnings forecasts, relate *positively* to future excess stock returns. In other words, analysts'

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recommendations. Unsophisticated investors may be more likely to rely on analysts' stock recommendations, which require minimal analytical processing. As an example, Bonner et al. (2003) find that sophisticated investors have greater knowledge of the analyst- and forecast-specific factors that predict forecast accuracy, and they use these factors to predict the relative accuracy of analysts' forecast revisions.

[2] In certain specifications, Bradshaw (2004) finds no relation between residual income valuations and stock recommendations.

[3] These results are consistent with those in Gleason et al. (2007) who conclude that analysts rely on simple heuristics rather than formal valuation models in setting price targets. Bradshaw and Brown (2005) conclude that analysts face greater incentives to provide accurate earnings forecasts than target prices.

earnings forecasts are useful inputs into residual income valuation models, yet they tend to relate negatively or insignificantly to analysts' stock recommendations. Furthermore, LTG forecasts, which most closely align with analysts recommendations, relate *negatively* to future returns. It seems that analysts recommend stocks with strong growth potential, even if such potential is already impounded into the stock price. Consistent with these results, Bradshaw (2004) shows that stock recommendations are not significantly associated with buy-and-hold one-year future returns.[4] Recommendations do not appear to capture stocks' intrinsic values relative to their current prices.

Why do analysts appear to avoid using their valuable earnings forecasts in a sophisticated manner in setting their recommendations (i.e., fail to practice what they preach)? This surprising result makes this area of research interesting and motivates further examination of the link between valuation estimates and recommendations, and their relations to future stock returns. It could be that analysts have incentives other than using their recommendations to signal mispriced stocks. In fact, analyst behavior has received wide-spread criticism in the financial press and several groups have called for reforms to the analyst industry.[5] We examine how recent regulations (e.g., Reg FD, NASD Rule 2711, NYSE Rule 472, and the Global Research Analysts Settlement) affect the way valuation estimates map into recommendations and subsequently relate to future stock returns. Specifically, we test for differences in these relations between the 1993-1999 and 2000-2005 periods to determine the impact of Reg FD. Then, we tests for differences between the 2000-2002 and 2003-2005 periods to test for effects of other regulations.

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[4] Other recent studies find mixed results on the usefulness of stock recommendations (Womack 1996; Barber et al. 2001, 2003; Mikhail et al. 2004; Li 2005; Gleason et al. 2007).

[5] Boni and Womack (2002) provide a useful overview of these issues and list many references to both practitioner and research articles.

Our results show that several important relations change across the regulation periods, while some interesting relations seem unaffected by the regulations. Prior to Reg FD, we find results generally consistent with Bradshaw (2004), even though our sample is substantially larger than his. Following Reg FD, we show that the negative relation between recommendations and residual income valuations becomes significantly smaller and even turns positive for one of our models. However, this change appears to be attributable primarily to regulations other than Reg FD. LTG forecasts continue to have a positive relation with recommendations in the post-Reg FD period, but the relation is weaker. PEG valuations have an increasingly positive relation with stock recommendations over our regulatory period.

In our next set of tests, we examine how valuations and recommendations relate to future stock returns. Like Bradshaw (2004), we find that residual income valuations relate positively to future returns. This relation becomes more positive following Reg FD. Furthermore, the increasing positive relation appears attributable to Reg FD as we find no evidence of an impact of other regulations. We find that the relation between LTG forecasts and future stock returns is significantly negative in the pre-Reg FD period and immediately following Reg FD. After regulations subsequent to Reg FD, LTG and future stock returns become slightly less negatively related. Finally, and perhaps of greatest interest to investors, stock recommendations have a significantly *negative* relation with future stock returns. Even though analysts' earnings forecasts are useful (in residual income valuation models) for predicting stock performance, their recommendations seem to predict the opposite performance. We find that the negative relation between recommendations and future stock performance persists after Reg FD but subsequent regulations have significantly reduced this negative relation. Overall, we conclude that regulatory reforms seem to be adjusting analysts' outputs (i.e., earnings forecasts and stock recommendations) in the expected direction, but the adjustment may be incomplete. Reg FD has played a greater role in increasing the usefulness of earnings forecasts, whereas regulations subsequent to Reg FD have had a greater effect on stock recommendations.

In the next section we summarize the related literature and discuss our framework for analyzing the analyst/investor relation, highlight objectives of recent regulations (and discuss some research findings related to these regulations), and present our hypotheses. In Section III we briefly describe the valuation models, and in Section IV we discuss our sample selection and descriptive statistics. Section V provides our main empirical findings as well as results from additional analyses. Section VI concludes.

II. PRIOR RESEARCH AND HYPOTHESES

In this section, we first describe the framework in which we analyze the analyst/investor relation. Then we focus on identifying factors that can affect this relation when examining analysts before and after recent regulatory reforms. Finally, we present our hypotheses.

Analyst/Investor Relation

Schipper (1991) encourages research to help better understand how earnings forecasts relate to stock recommendations. She argues that forecasts should be viewed as an input into producing a final output (i.e., a recommendation) and not just a standalone final output. We expect the following relations between analysts and investors. First, analysts gather firm-specific, industry-specific, and economy-wide information to generate earnings forecasts. Next, analysts input these earnings forecasts into a valuation model to compute an intrinsic value of the firm. Then, analysts issue recommendations based on comparing estimates from these valuation models with current stock prices. When the model indicates an intrinsic value above (below) the current price, analysts will issue a buy (sell) recommendation. Investors then adjust prices for the analyst's recommendation. If the academic research correctly identifies the analyst's *unobservable* valuation model, then a positive relation between valuation estimates and *observable* stock recommendations is expected.

Bradshaw (2004) examines whether valuation estimates based on analysts' earnings forecasts are consistent with their stock recommendations. He considers two residual income models, the PEG model, and LTG forecasts.[6] All valuation estimates rely on analysts' earnings forecasts. Perhaps surprisingly, he finds that residual income valuations are either unrelated to or *negatively* related to recommendations. But, these valuations are *positively* associated with future stock performance.[7] In addition, he finds that recommendations are *unrelated* to future stock performance.[8] From this evidence, one concludes that analysts' earnings forecasts provide useful information to investors for predicting future stock performance but analysts' recommendations do not. In other words, analysts do not appear to practice (recommend) what they preach (forecast). Our primary objective is to investigate the effects of recent regulations affecting analysts' work environments on the above relations.

Mitigating Factors

Several factors provide possible explanations for Bradshaw's surprising results. For example, after issuing an earnings forecast, the analyst might not employ rigorous valuation

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[6] Details on these four models appear in Section III.

[7] Frankel and Lee (1998) also find a positive relation between residual income valuations and future stock performance.

[8] Womack (1996) and Barber et al. (2001) find that recommendation changes are associated with future stock returns. Other recent studies find mixed results on the usefulness of stock recommendations (Barber et al. 2003; Mikhail, Walther, and Willis 2004; Li 2005; Gleason et al. 2007). The combined evidence suggests that analysts' earnings forecasts provide useful information for measuring intrinsic values but that analysts' recommendations do not. Barber et al. (2006) suggest that market prices react slowly to the information contained in recommendations.

models but instead rely on simple heuristics, whereas investors rely on more sophisticated residual income models. Bradshaw finds evidence consistent with LTG forecasts being the most important determinant of stock recommendations, regardless of the degree to which these expectations are already impounded in stock prices. These results suggest that analysts tend to rely on valuation heuristics to a greater extent than on more "theoretically driven" residual income models. These archival results are consistent with findings in broad surveys of analysts (e.g., Barker 1999; Block 1999) as well as detailed analyses of small samples of research reports (e.g., Bradshaw 2002). Bradshaw (2002) examines 103 U.S. analyst reports and finds that analysts frequently support their stock recommendations with a PEG model. Asquith et al. (2005) investigate *Institutional Investor* "All American" analysts, presumably the most sophisticated analysts, and find that only 13 percent of their reports refer to discounted cash flows in formulating price targets. Results in Gleason et al. (2007) are also consistent with analysts' use of simple heuristics rather than more rigorous residual income models.

In addition, in setting their recommendations, analysts may consider factors other than the intrinsic value estimates relative to current stock prices. Rather than maximizing gains to investors, analysts may be serving personal objectives, such as increasing their compensation, improving relations with management, garnering investment banking business for the brokerage firm, "hyping" the stock to garner brokerage trading volumes, and increasing the value of shares personally owned (e.g., Lin and McNichols 1998; Michaely and Womack 1999, 2005; Ertimur et al. 2007; Ke and Yu 2007). For example, Gimein (2002) claims that investment advice offered by analysts is "so dishonest and fraught with conflicts of interest that it has become worthless" (see also Heflin et al. 2003). As evidence of this, prior research demonstrates that affiliated analysts (i.e., those having direct investment banking business with the firm) issue more optimistic forecasts (Dugar and Nathan 1995; Lin and McNichols 1998; Dechow, Hutton, and Sloan 2000). Das, Levine, and Sivaramakrishnan (1998) and Lim (2001) suggest that forecast optimism is used to increase access to management, especially in cases where the information asymmetry between management and investors is high.[9]

If stock recommendations are set based on incentives other than (only) identifying mispriced stocks, then the relation between stock recommendations and future stock performance is expected to be low or even negative. This may further explain why Bradshaw (2004) finds no significant relation between the level of analyst recommendations and future annual excess returns during his 1994-1998 sample period.[10] These alternative motivations are certainly consistent with the well-documented optimistic bias in analysts' stock recommendations.[11]

Regulatory Reforms

In recent years several important developments in the regulatory environment have affected sell-side financial analysts, and these reforms have the potential to significantly change analysts' incentives or behavior and therefore their output (e.g., earnings forecasts and stock recommendations). Our study tests whether relations between recommendations and valuation

[9] Francis et al. (2004) provide an in-depth review of the evidence on security analyst independence and conclude that there is strong evidence that U.S. analysts behave in a biased manner. Using the tests in Bradshaw (2004), Barniv et al. (2008) investigate common law versus code law countries and conclude that analyst bias is more pervasive in common law countries. This result is consistent with analysts' stock recommendations in common law countries being affected more by factors other than identifying mispriced stocks.

[10] Jegadeesh et al. (2004) find that recommendation levels are positively related to subsequent returns only for firms with favorable quantitative characteristics such as value stocks and positive momentum stocks. Womack (1996) and Barber et al. (2001) examine changes in analysts' recommendations and conclude that these are positively associated with future excess returns. In this paper, we choose to follow Bradshaw (2004) and Jegadeesh et al. (2004) and examine recommendation levels. First, we want to be able to compare our results with those in Bradshaw (2004). Second, we want to examine recommendations the way a non-computer generated trading investor would process recommendations. Such an investor would find a stock, check out the outstanding recommendations, and then buy/not buy/sell.

[11] For example, Jegadeesh et al. (2004) report that approximately 80 percent of the recommendations are Buy or Strong Buy, and only five percent are Sell or Strong Sell.

estimates are affected by changes in the regulatory environment over time and thus sheds light on whether potential changes in the relations are consistent with the objectives of the reforms.

Reg FD, issued by the Securities and Exchange Commission (SEC) in October 2000, prohibits firms from selectively disclosing management information to analysts. The purpose of the reform was to level the playing field by giving all equal access to material information released by management. Some contend that prior to Reg FD, analysts would purposely bias their earnings forecasts to gain favor with management, thereby allowing easier access to inside information or investment banking business. If Reg FD eliminates the ability to gain privileged information, then one motivation for providing purposely biased earnings forecasts has been eliminated, presumably leading to improved usefulness of earnings forecasts.

Herrmann et al. (2008) find evidence to support this notion.[12] They conclude that Reg FD reduces the incentive for analysts to provide optimistically biased forecasts of internationally diversified firms, potentially improving the quality of analyst forecasts and the decisions of investors based on those forecasts. Others may argue that Reg FD has not led to improved earnings forecasts. Some research suggests that forecast accuracy decreases and forecast dispersion increases following Reg FD (e.g., Bailey et al. 2003; Agrawal et al. 2006). Based on their findings, Agrawal et al. (2006) conclude that a reduction has occurred in both selective guidance and the quality of analyst forecasts after Reg FD. Thus, although the intent of Reg FD is clear and should indicate a strengthened association between analysts' earnings forecasts and their stock recommendations, there is mixed empirical evidence regarding the possible effects of Reg FD on analysts' work environment and their earnings forecasts.

[12] Using the extent of a multinational firm's international operations to proxy for analysts' need to gather privileged information from management, Herrmann et al. (2008) show that the relation between forecast bias (optimism) and international diversification significantly declines (and even disappears) in the post-Reg FD period.

In addition to Reg FD, other recent regulatory reforms also potentially impact the output of financial analysts. Because of huge investor losses as a result of the crash of technology stocks between 2000 and 2002, regulators came under pressure to "fix" analysts' research reports. It was analysts' overly optimistic research reports that were often cited as a key factor leading to the run up of security prices in the late 1990's. For example, by the end of 1999, less than one percent of analysts provided "sell" recommendations (Bogle 2002). The investing public argued that analysts employed by brokerage firms that offered both investment banking business and research reports faced a conflict of interest. The conflict arose because in an attempt to maintain investment banking business for the brokerage firm, analysts faced pressure to provide favorable research reports (i.e., buy recommendations) instead of providing objective research to the investment community. As a result of these criticisms, regulators proposed NASD Rule 2711 (Research Analysts and Research Reports) and an amendment to NYSE Rule 472 (Communications with the Public) in 2002. In general, the proposed regulatory changes were directed at limiting interactions and flow of information between analysts who provide recommendation reports and the investment banking business of the brokerage firm.[13] These proposals were formally accepted by the SEC on July 29, 2003.[14]

In December, 2002, the SEC announced the Global Research Analyst Settlement which was enforced in April, 2003. Here, the SEC reached a legal settlement with the New York Attorney General, NASD, NYSE, state regulators, and ten of the top U.S. investment firms. The

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[13] For a complete description of the rules see "www.nyse.com/pdfs/rule472.pdf" for NYSE Rule 472 (2002) and "finra.complinet.com/finra/display/display.html?rbid=1189&element_id=1159000466" for NASD Rule 2711 (2002).

[14] Rule 2711 covers restrictions on relationships between the investment banking and research departments, restrictions on review of a research report by the subject company, prohibition of certain forms of research analyst compensation, prohibition of promise of favorable research, restrictions on personal trading by research analysts, and disclosure requirements. This rule was introduced on May 10, 2002, but its implementation was subsequently delayed several times (SEC 2002). It seems likely that the mere "threat" of its implementation could have an effect on analyst behavior.

settlement describes how analysts from leading banks provided misleading information to investors, allegedly because of investment banking incentives.[15] In particular, the settlement discloses that analysts issued positive public information that conflicted with their negative views about the stock (De Franco et al. 2007). In other words, as discussed above, investment banking incentives can lead to misleading analyst behavior.[16]

There is some evidence that these regulations have impacted analysts' recommendations. Kadan et al. (2006) show that prior to these regulations, analysts were 40 percent more likely to issue an optimistic recommendation for stocks that had recently undergone an initial public offering or seasoned equity offering. This probability increased by an additional 12 percent when the recommendation was made by an affiliated analyst. These effects vanished after regulations. Barber et al. (2006) support this notion by documenting a decrease in the overall percentage of buys in broker ratings between January 2000 and June 2003, particularly among sanctioned investment banks. Consistent with these findings, Ertimur et al. (2007) and Ke and Yu (2007) show that the improvement is analysts' recommendations around recent regulations was greater for analysts that likely faced higher conflicts of interest.[17]

In summary, recent regulations have addressed bias in analysts' earnings forecasts and stock recommendations. If these regulations have had their intended effects, we should observe

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[15]The settlement also enforces the brokerage firms to make structural changes in the production and dissemination of analyst research.

[16] The SEC further issued several releases governing investment firms' disclosure practices in 2003 (e.g., Regulation Analyst Certification, AC, 2003). Regulation AC requires certifications by analysts that the views expressed in their research reports accurately reflect their personal views. Analysts are required to disclose whether they receive any direct or indirect compensation for their reports. Analysts who cannot certify that they have not received compensation for a specific report must disclose the magnitude and source of the compensation. Finally, the Sarbanes-Oxley Act came into effect in 2002, potentially affecting the quality of financial reporting and thus the work of financial analysts.

[17] Specifically, Ke and Yu (2007) provide an interesting study of how analyst ability, analyst independence, and investor sentiment affect the efficiency with which analysts incorporate their own earnings forecasts into stock recommendations around recent regulations.

an increase in the usefulness of analysts' output – earnings forecasts and stock recommendations. This leads us to the following set of hypotheses.

H1: Following recent regulations, the relation between analysts' stock recommendations and earnings forecast-based residual income (heuristic) valuations is expected to become more (less) positive.

H2: Following recent regulations, the relation between earnings forecast-based residual income valuations and future stock returns is expected to become more positive.

H3: Following recent regulations, the relation between analysts' stock recommendations and future stock returns is expected to become more positive.

III. A BRIEF DESCRIPTION OF VALUATION MODELS

In this section, we briefly describe the valuation models used in this paper.[18] Following prior literature (e.g., Ohlson 1995; Frankel and Lee 1998; Bradshaw 2004), we estimate the residual income model as the present value of expected residual income for the next five years plus a terminal value:

$$V_t = BVPS_t + \sum_{\tau=1}^{5} \frac{E_t[\,RI_{t+\tau}\,]}{(1+r)^{\tau}} + \frac{E_t[\,TV_{t+5}\,]}{(1+r)^{5}}. \tag{1}$$

To estimate (1), we require availability of book value per share (*BVPS*) in year *t* from Compustat and forecasted earnings per share for years $t+1$ and $t+2$ from I/B/E/S. If available, we use analysts' forecasts of years $t+3$ through $t+5$. If not available, we extrapolate earnings

[18] For more on these models, see Frankel and Lee (1998), Lee et al. (1999), Liu et al. (2002), Easton (2004), and Hope et al. (2008).

forecasts for these years using the earnings forecast for year *t+2* and the long-term growth forecast.[19] Residual income (*RI*) equals forecasted earnings, less the discount rate (*r*) times the prior year's book value. Future book values are extrapolated from book value in year t using the clean surplus assumption (i.e., $BVPS_{t+1} = BVPS_t + EPS_{t+1} - DPS_{t+1}$), where future earnings, EPS_{t+1}, are forecasted earnings, and future dividends, DPS_{t+1}, are measured using the assumption of a constant payout ratio based on year *t*.

Due to the importance of assumptions embedded in the terminal value (*TV*) computation, we estimate two versions of the residual income model (Bradshaw 2004). The first, V_{RI1}, assumes that abnormal profits are driven away over time due to competitive pressures. In practice we build in a fade rate (ω) that implies that residual income reverts to zero over ten years:

$$V_{RI1,t} = BVPS_t + \sum_{\tau=1}^{5} \frac{E_t[RI_{t+\tau}]}{(1+r)^{\tau}} + \frac{\omega E_t[RI_{t+5}]}{(1+r-\omega)(1+r)^{5}} \tag{2}$$

The second specification of the residual income valuation model (V_{RI2}) assumes that residual income in the terminal year persists in perpetuity, which is a more optimistic assumption than the fade-rate assumption used for V_{RI1}:

$$V_{RI2,t} = BVPS_t + \sum_{\tau=1}^{5} \frac{E_t[RI_{t+\tau}]}{(1+r)^{\tau}} + \frac{E_t[RI_{t+5}]}{r(1+r)^{5}}. \tag{3}$$

Barker (1999), Block (1999), Bradshaw (2002), and Chen et al. (2004) discuss how analysts use price-earnings based techniques in practice. Numerous articles in the financial press describe the pervasiveness of the use of the "PEG ratio" as a basis for stock recommendations. For example, Peter Lynch advocates the PEG ratio in his book *One Up on Wall Street* (Lynch 2000). The *PEG* ratio is defined as:

[19] For example, if forecasted earnings for year t+2 equal $1.00 and the long-term growth forecast is 10 percent, then forecasted earnings for year t+3 is $1.10, forecasted earnings for year t+4 is $1.21, and forecasted earnings for year t+5 is $1.33. To provide this extrapolation, we require that forecasted earnings for year t+2 be positive.

$$PEG_t = \frac{P_t / E_t\left[EPS_{t+2}\right]}{LTG_t * 100}, \tag{4}$$

where P is stock price, $E_t[EPS_{t+2}]$ is forecasted earnings per share in year $t+2$, and LTG is the long-term growth forecast. Following Bradshaw (2004), we compute the *PEG* valuation as:

$$V_{PEG,t} = E_t\left[EPS_{t+2}\right] * LTG_t * 100 \tag{5}$$

V_{RI1}, V_{RI2}, and V_{PEG} are divided by current stock price. To the extent that the valuation estimate is greater (less) than current price, the valuation model suggests an under (over) priced stock and therefore higher (lower) future returns, on average.

Finally, although not a valuation estimate per se, we include *LTG* forecasts as our fourth metric. This is important since *LTG* forecasts seem to be the primary measure used by analysts in setting their recommendations prior to regulations (Bradshaw 2004), yet they have a strong *negative* relation with future stock returns. We are interested in the impact that recent regulations have on the use of heuristics by analysts. While an increase in the relation between residual income valuations and stock recommendations might provide indirect evidence of a reduced reliance on heuristics, this is not necessarily the case. We believe it is important to provide a direct test. Providing results for each of these contrasting relations (heuristics versus theoretically-driven residual income values) provides additional evidence for understanding the link between analysts' earnings forecasts and their recommendations.

IV. DATA, SAMPLE, AND DESCRIPTIVE STATISTICS

We obtain data on annual consensus earnings forecasts, projections of long-term earnings growth, and stock recommendations from I/B/E/S for the sample period January 1993 – May

2005 for an extensive sample of firms.[20] Our initial sample includes 425,158 observations that have stock recommendations and data necessary to create our four valuation estimates.[21] Next, we exclude observations for months without changes in stock recommendations.[22] Since recommendations can be fairly sticky across months, using only months that involve a change in recommendations provides a more realistic setting of when analysts are more likely to incorporate current information into their recommendations (as opposed to current recommendations reflecting stale information). The final sample of consists of 187,889 monthly observations representing 8,079 firms. We have 112,477 observations for our pre-Reg FD (1993-1999) sample and 75,412 observations for our post-Reg FD (2000-2005) sample. Note that our pre-Reg FD sample is substantially larger than the one employed by Bradshaw (2004) of 15,318 observations over the 1994-1998 period (with LTG available, which we require for all of our tests).[23] Within the post-Reg FD sample, we have 36,799 observations prior to other regulations (2000-2002) and 38,613 observations for 2003-2005 (after other regulations). We refer to the periods before and after other regulations as the pre-OtherReg and post-OtherReg periods.

Panel A of Table 1 presents descriptive statistics for the pre- and post-Reg FD periods. Consistent with our prediction that Reg FD should reduce analyst optimism, the mean recommendation (*REC*) is significantly lower (at the one percent level) in the post-Reg FD era (3.72) than in the pre-Reg FD era (3.96) (1 = Strong Sell to 5 = Strong Buy). The percentage of buy and strong buy recommendation decreases from 67.7 to 47.1, and the percentage of sell and

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[20] Bradshaw (2004) uses First Call as his source for analyst data. First Call and I/B/E/S differ in that First Call includes consensus data for a month only if the consensus was revised during the month. I/B/E/S is more comprehensive in that it includes all months, including those with no changes in the consensus. We base our main results on using change months only (consistent with Bradshaw), but we show later in the paper that results are robust to using the full sample of observations.

[21] Results are similar if we relax the requirement that *LTG* forecasts be available (and thus have larger sample sizes).

[22] As a sensitivity test near the end of the paper, we discuss results when all months are included. All conclusions are unaffected. In addition, we have estimated all models after excluding consensus recommendations based on just one recommendation and the results are similar to those reported.

[23] As discussed below, we find results similar to Bradshaw (2004) for the pre-Reg FD period with a few exceptions.

strong sell recommendations increases from 1.1 to 4.4 percent. The means of V_{RI1}/P and V_{RI2}/P significantly increase and V_{PEG}/P and *LTG* significantly decrease.[24] As expected, firm size (market value of equity) increases. In addition, the number of analysts per firm also increases.

[Place TABLE 1 here]

Consistent with their high recommendation levels, analysts estimate high long-term growth rates (*LTG*) for the companies they follow – 18.9 percent and 18.0 percent for the pre- and post-Reg FD periods, respectively (and the difference is significant at the one percent level). In untabulated analyses, we find that the mean actual annual earnings growth is 8.4 percent and 11.5 percent in these periods. These findings suggest that *LTG* projections are high and optimistically biased, but that this optimism has decreased somewhat in the post-Reg FD period.

Panel B presents the results for the pre-OtherReg period (2000-2002) and post-OtherReg period (2003-2005). The mean recommendation continues to significantly decline, going from 3.89 to 3.58.[25] The percentage of buy and strong buy recommendations decreases from 57.2 to 42.1, and the percentage of sell and strong sell recommendations increases from 2.6 to 5.2 percent, and. V_{RI1}/P, V_{RI2}/P, and V_{PEG}/P increase significantly, but *LTG* forecasts decrease significantly from 20.2 percent to 15.9 percent. These results suggest that the major decreases in analysts' recommendations and *LTG* projections appear following other regulations.

Panels C and D of Table 1 provide correlations between variables. Consistent with the intent of regulations, the correlations between residual income valuations and stock

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[24]The fact that the mean recommendation *REC* is a buy and the mean residual income valuation estimates (V_{RI1}/P and V_{RI2}/P) are less than one suggests that analysts rely on more than just these valuations when deciding their stock recommendations (Bradshaw 2004). Unlike the residual income valuations, the *PEG* valuation is greater than the current price for the pre-Reg FD period (1.14) but is below current price for the post Reg FD (0.79).

[25] One potential alternative reason for the decline in recommendation levels over our sample period could be deteriorating economic conditions. We cannot exclude this possibility. However, it should be noted that recommendations are generally made with the explicit understanding that they represent whether a stock will underperform or outperform the market in general, and not necessarily whether the stock price is expected to decrease or increase. Thus, it is not necessarily the case that poorer economic conditions would lead to reduced recommendations in general.

recommendations increase over time. However, there is an increase in the positive correlation between V_{PEG}/P and recommendations, even though the correlation between V_{PEG}/P and future returns becomes insignificant post Reg FD and then becomes negative after other regulations. The correlation between residual income valuations and future returns is increasing, but that improvement occurs only around Reg FD. *LTG* forecasts and residual income valuations are negatively correlated, explaining why residual income valuations and future returns are positively correlated, while *LTG* forecasts and future returns are negatively correlated.

V. REGRESSION RESULTS

As in Bradshaw (2004), each coefficient reported in the tables represents the mean coefficient from 12 subsample regressions. The 12 subsamples are created by partitioning all observations based on one-year-ahead earnings forecast horizons (i.e., months t-1 to t-12). This controls for systematic differences in earnings forecast characteristics as the end of the period nears (Brown 2001; Bradshaw 2004). It is an empirical regularity that analysts walk down their forecasts as the year passes, and forecasts made near the end of the year are more accurate and less optimistic than those made near the beginning of the year. By running the regression for each fiscal month, we prevent mixing short-horizon earnings forecasts with long-horizon forecasts. In other words, we prevent mixing valuation estimates generated from more optimistic, less accurate forecasts (i.e., long-horizon forecasts) with those generated from less optimistic, more accurate forecasts (i.e., short-horizon forecasts).[26] Reported t-statistics are based on the

[26] As an example of this issue, we find that V_{RI1}/P uniformly decreases over the 12-month horizon. The mean of V_{RI1}/P is 12 percent lower in month t-1 compared to month t-12. The same decreasing pattern is observed for V_{RI2}/P (14 percent lower in month t-1) and V_{PEG}/P (24 percent lower in month t-1). Thus, Bradshaw's (2004) approach directly controls for this horizon effect in analysts' forecasts.

standard error of the monthly coefficients, using the adjustment for serial correlation across months.[27,28]

The adjusted R^2s presented are means across the 12 months. We estimate the regressions using quintile rankings of the independent variables. The quintile rankings are designated by allocating observations in equal numbers to quintiles within each month based on the distribution of the variable in that month. The quintile rankings are scaled to range between 0 and 1.[29]

Tests of Effects of Regulatory Reforms on Relations between Stock Recommendations and Valuation Estimates (Hypothesis 1)

To test the effect of Reg FD on the relation between valuation estimates and stock recommendations, we estimate the following model.

$$REC = \alpha_0 + \alpha_1 RegFD + \alpha_2 VALUATION + \alpha_3 VALUATION * RegFD + \varepsilon \tag{6}$$

where *VALUATION* is one of the four valuation estimates and *RegFD* is an indicator variable that takes the value of one following implementation of Reg FD, zero otherwise. α_2 provides an estimate of the relation between recommendations and valuations in the pre-Reg FD period. If α_3 is greater (less) than zero, then the relation between recommendations and valuations has increased (decreased) following Reg FD.

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[27] Standard errors are multiplied by an adjustment factor, $\sqrt{\frac{(1+\Phi)}{(1-\Phi)} - \frac{2\Phi(1-\Phi^n)}{n(1-\Phi)^2}}$, where n is the number of months and Φ is the first-order autocorrelation of the monthly coefficient estimates (Abarbanell and Bernard 2000; Bradshaw 2004).

[28] Since each of the fiscal month regressions contains multiple observations for the same firm, there is likely some residual dependence, understating the standard error in each of the monthly regressions. However, the monthly coefficients are unbiased. And since we base our reported t-statistics on the mean of the monthly coefficients (not the monthly standard errors), the reported significance levels are unaffected.

[29] We have also estimated the models using five-group, three-group, and two-group (above/below median) ordered logit regressions. Untabulated results show that no inferences are affected with these alternative estimation techniques.

Table 2 presents regression results. Contrary to what one might expect but consistent with Bradshaw's (2004) 1994-1998 results, the table shows that analysts' recommendations are positively related to heuristic-based valuation estimates but are negatively related to more rigorous residual income valuations in the pre-Reg FD period. Directly related to H1, we find that the interactions of both V_{RI1}/P and V_{RI2}/P with *RegFD* are positive and significant at the one percent level. These findings support the first hypothesis that Reg FD will better align analysts' recommendations with residual income valuations, which were developed using analysts' earnings forecasts. Also consistent with H1, we find that recommendations are significantly less positively associated with *LTG* following Reg FD (i.e., the interaction term is negative and significant at the one percent level), suggesting a reduced reliance on *LTG*. However, in contrast to our prediction, the relation between stock recommendations and *PEG* valuation slightly increases following Reg FD.[30] In conclusion, for three of the four models the results provide support for the first hypothesis, suggesting significant effects of Reg FD on the association between analyst recommendations and valuation estimates.

[Place TABLE 2 here]

For our test of the effects of other regulations, we estimate a similar model but limit the sample period to the post-Reg FD era and repeat the above test after replacing *RegFD* with *OtherReg*, an indicator variable that takes the value of one for the 2003-2005 period (post-OtherReg) and zero for the 2000-2002 period (pre-OtherReg).

$$REC = \alpha_0 + \alpha_1 OtherReg + \alpha_2 VALUATION + \alpha_3 VALUATION * OtherReg + \varepsilon \tag{7}$$

Table 3 presents regression results. The coefficients on V_{RI1}/P and V_{RI2}/P are significantly negative, indicating that residual income valuations remain significantly negatively related to

[30]Coefficient estimates in the post-Reg FD period are as follows (untabulated): V_{RI1}/P is significantly negative, V_{RI2}/P is not significantly different from zero, and V_{PEG}/P and *LTG* are significantly positive.

recommendations after Reg FD but before other regulations. The relation between residual income valuations and recommendations becomes significantly more positive after other regulations, as indicated by their interactions with *OtherReg*. These results are consistent with the first hypothesis. In fact, untabulated results show that the coefficient on V_{RI1}/P is indistinguishably different from zero in the post-OtherReg period and the coefficient on V_{RI2}/P becomes significantly positive. Thus, it appears that other regulations have played a greater role than has Reg FD in aligning residual income valuations and analysts' recommendations. At least with respect to V_{RI2}/P, the puzzling negative relation between residual income valuations and recommendations now appears to be positive, as one might expect prior to observing results in prior literature.

[Place TABLE 3 here]

Contrary to our first hypothesis, we do not detect a decline in the relation between *REC* and heuristics (*LTG* and V_{PEG}/P) after other regulations. The relation between *REC* and V_{PEG}/P continues to increase. The relation between *REC* and *LTG* also increases after having been reduced immediately following Reg FD.

To summarize, the results in Tables 2 and 3 suggest that recent regulations have had an effect on analyst behavior. Specifically, we document a greater reliance on residual income valuations in arriving at stock recommendations following recent regulations. These results are consistent with the objectives of Reg FD and the other regulations and provide support for H1. However, the results for the effects of regulations on heuristics-based valuation estimates (V_{PEG}/P and *LTG*) are mixed for Reg FD and contrary to expectations for other regulations.

Tests of Relations between Future Excess Returns and Valuation Estimates (Hypothesis 2) and Stock Recommendations (Hypothesis 3)

We now turn to testing the relation of future excess returns with both valuation estimates and stock recommendations. We compute one-year-ahead buy-and-hold size-adjusted returns (*SAR*) as:

$$SAR_i = \left[\prod_{\tau=1}^{12} \left(1 + r_{i,t+\tau} \right) - \prod_{\tau=1}^{12} \left(1 + r_{size,t+\tau} \right) \right], \tag{8}$$

where $r_{i,t+\tau}$ is the monthly raw stock return for firm i in month $t+\tau$, and $r_{size,t+\tau}$ is the month $t+\tau$ return of the size decile to which firm i belongs as of the beginning of the fiscal year. Using I/B/E/S price and dividend data (supplemented with Compustat data), we cumulate returns beginning in the month subsequent to the date of the consensus recommendation. We chose to use a one-year-ahead return horizon for two reasons. First, this is the horizon employed by Bradshaw (2004) so our results are directly comparable to his. Second, recommendations are generally provided by analysts with the intention of giving guidance over an extended period of time (e.g., 6 to 24 months).

To test the second hypothesis, we run the following regression to estimate the relation between future excess returns and the valuation estimates:

$$SAR = \beta_0 + \beta_1 RegFD + \beta_2 VALUATION + \beta_3 VALUATION * RegFD + \varepsilon \tag{9}$$

For the third hypothesis, we consider the relation between future returns and stock recommendations.

$$SAR = \beta_0 + \beta_1 RegFD + \beta_2 REC + \beta_3 REC * RegFD + \varepsilon \tag{10}$$

Panel A of Table 4 shows regression results for (9) and (10). Consistent with the findings of Frankel and Lee (1998) and Bradshaw (2004), we document that both V_{RI1}/P and V_{RI2}/P are positively and significantly related to future excess returns before Reg FD. In addition, we find that this positive relation increases following Reg FD (and in fact doubles). These results provide support for the second hypothesis. The coefficients on *LTG* and V_{PEG}/P are *negatively* related to future excess returns prior to Reg FD. The introduction of Reg FD did appear to make V_{PEG}/P significantly less negatively related to future returns (i.e., the interaction is positive and significant at the one percent level). For *LTG*, on the other hand, there is no significant effect of Reg FD. The final column of Panel A in Table 4 shows that recommendations are negatively related to future excess returns. After enactment of Reg FD, this negative relation persists. This suggests that Reg FD had no impact on the seemingly irrational relation between analyst recommendations and security returns.

[Place TABLE 4 here]

In Panel B, we examine whether valuations are incremental to stock recommendations. As discussed previously, to the extent that analysts' recommendations are not derived based on valuation models, the two can provide incremental effects. We first note that results for all four valuation estimates (reported in Panel A) and the effects of Reg FD are unaffected by adding recommendations to the regression. This provides further evidence that analysts' stock recommendations are influenced by many other factors. The biggest difference in the pre-Reg FD period is for *LTG*. Much of this variable's explanatory power is lost when testing for an incremental effect, which is consistent with our earlier result that recommendations appear most closely related to *LTG* (as opposed to residual income valuations). Results for the post-Reg FD are also very similar. Perhaps the most interesting result is that when controlling for V_{PEG}/P or *LTG*, the relation between stock recommendations and future excess returns becomes even more negative in the post-Reg FD period. This is not the case for residual income valuations. The ability of residual income valuations to explain future returns prevents the negative relation between recommendations and future returns from becoming increasingly negative.

Table 5 provides analyses of effects of other regulations (*OtherReg*) on the relations between future returns and valuation estimates and recommendations. The main findings reported in Panel A are as follows. First, the positive relation between residual income valuations and future returns remains the same before and after other regulations. Second, the other regulations do seem to have had an effect on the relation between stock recommendations and future returns, as the interaction effect is significantly positive. These results provide support for the third hypothesis. When we consider the incremental effects of valuations and stock recommendations for future returns (reported in Panel B), only one conclusion changes. The negative relation between stock recommendations and future returns does not become weaker when controlling for *LTG* (i.e., column 4 of Panel B). In general, the results in Table 5 further demonstrate that other regulations relate primarily to improvements in stock recommendations (as opposed to analysts' earnings forecasts) and this improvement is incremental to valuation estimates based on analysts' earnings forecasts.

[Place TABLE 5 here]

Sensitivity Analyses

Results for observations with no change in consensus

Recall that we base our results on using only monthly observations for which there has been a revision in the consensus recommendation. We use these observations to be consistent with Bradshaw (2004). However, as a sensitivity analysis, we repeat the tests using the full sample of observations from I/B/E/S data (i.e., including monthly observations with no change in consensus recommendation). This approach has the advantage of significantly increasing the sample size and thus the power of our tests. In fact, the sample size increases to 425,128. However, the results are quite similar to those reported previously, which provides some assurance that our findings are not unduly influenced by the use of a smaller sample.

Standard errors adjusted for clustering at the firm level

In Tables 2-5 we report coefficients using the mean coefficient from 12 fiscal month regressions. As an alternative, we consider estimating coefficients using a pooled model and use firm cluster adjusted standard errors. The pooled model has the disadvantage (as discussed previously) of mixing long-horizon and short-horizon earnings forecasts but the advantage of not relying on the average of only 12 monthly coefficients, which potentially reduces statistical power. Under this alternative approach, we find that coefficients are remarkably close to those reported in the tables. All conclusions reported from Tables 2 and 3 (i.e., the relations between stock recommendations and the four valuation estimates) are unaffected.

We do, however, notice some differences for results reported in Tables 4 and 5 (i.e., the relations with future returns). *LTG* is significantly more negatively related to future returns after Reg FD but significantly less negatively related to future returns after other regulations. These results are consistent with other regulations having their intended effect of reducing analysts' reliance on heuristics in setting stock recommendations. Furthermore, the conclusion that the increasing positive relation between residual income valuations and future returns is attributable primarily attributable to Reg FD (and not other regulations) is even more apparent. In summary, while we note some differences in results, overall conclusions regarding the effectiveness of regulations are unaffected.

Bear market and bull market effects

Our research period can be characterized by periods of primarily a bull market until March 2000, bear market from April 2000 through March 2003, and another bull market commencing in April of 2003. To test whether our inferences are affected by bull versus bear markets in addition to the effects of regulatory reforms, we re-estimate regressions using bull or bear monthly indicators.[31] The overall tenor of our results is the same. We do find that bull markets have positive effect on analysts' recommendations and excess returns in the pre-Reg FD.

VI. CONCLUSION

To date there has been surprisingly little research on analysts' recommendations and analysts' use of valuation models. A priori, the relation seems straightforward. Analysts input their earnings forecasts into the theoretically correct valuation model, such as a residual income model, to develop a valuation estimate. Analysts compare this valuation to current stock price. To the extent that the valuation estimate exceeds current stock price, analysts would issue a buy recommendation. Alternatively, if the valuation estimate is below the current stock price, analysts would issue a sell recommendation. Thus, it seems likely that residual income valuations and stock recommendations would have a positive relation and each would relate positively to future returns. Furthermore, if stock recommendations completely capture the information in valuation estimates, then valuation estimates would have no incremental explanatory power for future returns. However, while these arguments seem consistent with rational analyst behavior, prior research documents that these relations do not exist as expected

[31] For the entire 1993-2005 research period, we use a monthly indicator that equals one during bull markets and zero during the bear markets. We also use the monthly indicator for separate analysis during the post-Reg FD periods (2000-2005) and find no significant effects.

and in some cases exist in the opposite direction.

As an example, Bradshaw (2004) shows that residual income valuations, developed using analysts' earnings forecasts, relate negatively to analysts' recommendations yet relate positively to future returns. Why are analysts' earnings forecasts in residual income valuation models useful to investors (i.e., help in predicting future stock performance) yet analysts do not appear to use them in setting their recommendations? In other words, why do analysts not practice (recommend) what they preach (forecast)?

Because of these inconsistencies (along with the crash of technology stocks in the early 2000's), analyst activity has come under severe public scrutiny. Regulators were called upon to "fix" the analyst industry. The SEC enacted Regulation Fair Disclosure (Reg FD) in 2000, which prohibited management from disclosing material information to selected analysts. Some contend that analysts purposely biased their forecasts to gain favor with management, thereby allowing easier access to privileged information. Reg FD disallows the release of privileged information and therefore reduces at least one of the incentives for analysts to bias their forecasts.

Analysts were also criticized for the apparent conflict of interest that existed within brokerage firms. Analysts in the research department (i.e., those providing stock recommendations) felt pressure from those in the investment banking department to provide only favorable reports. Issuance of unfavorable reports could reduce investment banking business, a tremendous source of revenue for brokerage firms. Thus, analysts had incentives in issuing their recommendations beyond providing objective, reliable information to the investing public. In response, the SEC accepted NASD Rule 2711, NYSE Rule 472, and the Global Research Analyst Settlement in late 2002 and 2003. In general, these regulations address research analysts' conflicts of interest and limit interactions and flow of information between an analyst and the investment banking business of the brokerage firm.

We are interested in the extent to which these regulations had their intended effects. Using a large sample of stock recommendations over the 1993-2005 period, we first examine the relation between analysts' stock recommendations and (1) theoretically-derived residual income models versus (2) valuation heuristics (i.e., price-to-earnings to growth (PEG) ratio and long-term growth (LTG) forecast). We then examine the relation between future returns and (1) stock recommendations, (2) residual income models, and (3) valuation heuristics. Finally, we consider the extent to which residual income models and valuation heuristics are incremental to stock recommendations in explaining future returns. We examine changes in these relations in the pre-Reg FD period (1994-1999) versus the post-Reg FD period (2000-2005). Within the post-Reg FD period, we examine changes before (2000-2002) and after (2003-2005) other regulations (i.e., NASD 2711, NYSE Rule 472, and Global Research Analyst Settlement).

We report the following results. The documented negative relation between stock recommendations and residual income valuations diminishes in the post-Reg FD period and even becomes positive following other regulations. We also find evidence of a reduced analyst reliance on long-term growth forecasts in providing a stock recommendation in the post-Reg FD period. For our tests of a relation with future returns, we show that residual income valuations have an increasingly positive relation in the post-Reg FD period. This change is due primarily to Reg FD itself rather than other regulations. This finding implies that Reg FD had the effect of increasing the useful of earnings forecasts to investors. Also of interest to investors is our finding that the negative relation between stock recommendations and future returns still persists but is diminishing following regulations subsequent to Reg FD. Thus, it appears that in many ways regulations are having their intended effects but the effects on analysts' outputs may be incomplete.

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TABLE 1
Descriptive Statistics

Panel A: Descriptive Statistics for Pre- and Post-Reg FD Periods

	Pre Reg-FD (1993-1999) N = 112,477			Post Reg-FD (2000-2005) N = 75,412			Difference	
Variables	**Mean**	**Median**	**SD**	**Mean**	**Median**	**SD**	**t-test**	**Wilcoxon Z**
REC	3.96	4.00	0.53	3.72	3.75	0.54	-92.5***	-89.7***
%Buy	67.7%			47.1%				
%Sell	1.1%			4.4%				
V_{RI1}/P	0.63	0.58	0.37	0.66	0.62	0.43	19.0***	24.2***
V_{RI2}/P	0.70	0.66	0.42	0.77	0.74	0.53	32.1***	45.0***
V_{PEG}/P	1.14	1.06	1.03	0.79	0.85	1.23	-65.7***	-81.0***
LTG	18.85	16.07	10.47	18.01	15.17	10.22	-17.4***	-20.8***
SAR	-0.027	-0.092	0.598	-0.038	-0.090	0.514	-3.41***	1.62
MV	5,127	821	18,215	7,471	1,249	24,248	22.6***	51.7***
NUM	9.42	7.00	7.02	10.56	9.00	7.13	34.2***	41.2***

Panel B: Descriptive Statistics for Pre- and Post-OtherReg Periods

	Pre-OtherReg (2000-2002) N = 36,799			Post-OtherReg (2003-2005) N = 38,613			Difference	
Variables	**Mean**	**Median**	**SD**	**Mean**	**Median**	**SD**	**t-test**	**Wilcoxon Z**
REC	3.89	3.89	0.51	3.58	3.60	0.54	-74.7***	-74.1
%Buy	57.2%			42.1%				
%Sell	2.6%			5.2%				
V_{RI1}/P	0.62	0.55	0.49	0.71	0.66	0.36	28.9***	51.2***
V_{RI2}/P	0.65	0.62	0.57	0.89	0.85	0.46	62.3***	86.6***
V_{PEG}/P	0.74	0.87	1.54	0.83	0.82	0.84	10.9***	-13.6***
LTG	20.22	16.97	11.61	15.91	14.53	8.18	-58.6***	-48.8***
SAR	-0.041	-0.0982	0.513	-0.032	-0.104	0.515	1.95*	-0.69
MV	7,270	1,094	24,464	7,663	1,408	24,039	2.22**	20.6***
NUM	10.41	9.00	6.94	10.70	9.00	7.31	5.47***	3.42***

(Table 1 continued on next page)

TABLE 1 (continued)
Descriptive Statistics

Panel C: Pearson Correlations Before (1993-1999) and After (2000-2005) Reg FD[a]

	REC	*SAR*	V_{RI1}/P	V_{RI2}/P	V_{PEG}/P	*LTG*
REC	•	-0.119	-0.195	-0.129	0.228	0.339
SAR	-0.146	•	0.091	0.064	-0.163	-0.267
V_{RI1}/P	-0.127	0.197	•	0.935	0.460	-0.296
V_{RI2}/P	-0.075	0.170	0.888	•	0.543	-0.206
V_{PEG}/P	0.267	-0.017	0.466	0.545	•	0.407
LTG	0.283	-0.350	-0.307	-0.264	0.273	•

Panel D: Pearson Correlations Before (2000-2002) and After (2003-2005) OtherReg[b]

	REC	*SAR*	V_{RI1}/P	V_{RI2}/P	V_{PEG}/P	*LTG*
REC	•	-0.168	-0.170	-0.101	0.199	0.233
SAR	-0.115	•	0.209	0.188	-0.001	-0.411
V_{RI1}/P	-0.003	0.178	•	0.918	0.506	-0.305
V_{RI2}/P	0.113	0.148	0.860	•	0.603	-0.265
V_{PEG}/P	0.324	-0.053	0.460	0.584	•	0.136
LTG	0.269	-0.225	-0.267	-0.185	0.413	•

REC = mean consensus analyst recommendation, 1 = Strong Sell, 2 = Sell, 3 = Hold, 4 = Buy, 5 = Strong Buy.
%Buy = the percentage of recommendations rated Buy or Strong Buy.
%Sell = the percentage of recommendations rated Sell or Strong Sell.
V_{RI1} = residual income valuation with a five-year forecast horizon and a terminal value with a fade-rate assumption.
V_{RI2} = residual income valuation with a five-year forecast horizon and a terminal value with a perpetuity assumption.
V_{PEG} = forecasted earnings per share for a two-year forecast horizon times *LTG* (x 100).
LTG = consensus (median) projected long-term growth in earnings.
P = share price on the date of the consensus recommendation calculation.
SAR = annual size-adjusted return beginning the month following the recommendation.
MVE = market value of equity.
NUM = number of analysts following.
[a] Pearson correlations before (after) Reg FD are above (below) the diagonal.
[b] Pearson correlations before (after) other regulations are above (below) the diagonal.

TABLE 2
Relation between Recommendations and Valuation Estimates
Before (1993-1999) and After (2000-2005) Reg FD

Intercept	4.009***	3.954***	3.635***	3.536***
	(385.8)	(247.6)	(280.1)	(1891.9)
RegFD	-0.262***	-0.279***	-0.151***	-0.043*
	(-7.53)	(-7.58)	(-6.53)	(-1.89)
V_{RI1}/P	-0.304***			
	(-7.75)			
V_{RI2}/P		-0.186***		
		(-4.69)		
V_{PEG}			0.382***	
			(24.1)	
LTG				0.625***
				(103..2)
$V_{RI1}/P*RegFD$	0.187***			
	(5.52)			
$V_{RI2}/P*RegFD$		0.225***		
		(6.07)		
$V_{PEG}/P*RegFD$			0.065**	
			(2.02)	
*LTG*RegFD*				-0.214***
				(-16.9)
Adjusted R^2	0.109	0.096	0.145	0.193

The table presents the results of regressions of consensus stock recommendations on valuation estimates. Regressions are estimated based on one-year-ahead earnings forecast horizon (i.e., months t-1 to t-12). The table presents mean coefficients for these 12 monthly regressions. t-statistics are based on the standard error of the coefficient estimates across the 12 months, adjusted for autocorrelation in the monthly coefficients based on as assumed AR(1) autocorrelation structure. Standard errors are multiplied by an adjustment factor, $\sqrt{\frac{(1+\Phi)}{(1-\Phi)} - \frac{2\Phi(1-\Phi^{n})}{n(1-\Phi)^{2}}}$, where n is the number of months and Φ is the first-order autocorrelation of the monthly coefficient estimates. Adjusted R^2s presented are means across the 12 months. The regressions are estimated using quintile rankings of the independent variables. The quintile rankings are designated by allocating observations in equal numbers to quintiles within each month. The quintile rankings are scaled to range between 0 and 1 (e.g., (QUINTLE-1)/4)). *RegFD* equals 1 if an observation is in the post-Reg FD period (2000-2005) and zero otherwise (1993-1999). Other variables are defined in Table 1.
*, **, *** reflect significance at the 0.10, 0.05, and 0.01 level, respectively, based on two-tailed t-tests.

TABLE 3
Relation between Recommendations and Valuation Estimates
Before (2000-2002) and After (2003-2005) Other Regulations (OtherReg)

Intercept	4.022***	3.982***	3.805***	3.733***
	(760.5)	(661.5)	(537.3)	(437.1)
OtherReg	-0.346***	-0.412***	-0.378***	-0.283***
	(-9.15)	(-8.46)	(-9.48)	(-24.6)
V_{RI1}/P	-0.206***			
	(-8.90)			
V_{RI2}/P		-0.093***		
		(-4.33)		
V_{PEG}/P			0.309***	
			(40.1)	
LTG				0.347***
				(15.8)
V_{RI1}/P*OtherReg*	0.206***			
	(12.3)			
V_{RI2}/P*OtherReg*		0.293***		
		(24.2)		
V_{PEG}/P*OtherReg*			0.298***	
			(20.5)	
*LTG*OtherReg*				0.110***
				(8.08)
Adjusted R^2	0.102	0.292	0.165	0.150

The table presents the results of regressions of consensus stock recommendations on valuation estimates. Regressions are estimated based on one-year-ahead earnings forecast horizon (i.e., months t-1 to t-12). The table presents mean coefficients for these 12 monthly regressions. t-statistics are based on the standard error of the coefficient estimates across the 12 months, adjusted for autocorrelation in the monthly coefficients based on as assumed AR(1) autocorrelation structure. Standard errors are multiplied by an adjustment factor, $\sqrt{\frac{(1+\Phi)}{(1-\Phi)} - \frac{2\Phi(1-\Phi^n)}{n(1-\Phi)^2}}$, where n is the number of months and Φ is the first-order autocorrelation of the monthly coefficient estimates. Adjusted R^2s presented are means across the 12 months. The regressions are estimated using quintile rankings of the independent variables. The quintile rankings are designated by allocating observations in equal numbers to quintiles within each month. The quintile rankings are scaled to range between 0 and 1 (e.g., (QUINTLE-1)/4)). *OtherReg* equals 1 if an observation is in the post-other regulation period (2003-2005) and zero otherwise (2000-2002). Other variables are defined in Table 1.
*, **, *** reflect significance at the 0.10, 0.05, and 0.01 level, respectively, based on two-tailed t-tests.

TABLE 4
Relation between Annual Size-adjusted Returns and Stock Recommendations and Valuation Estimates Before (1993-1999) and After (2000-2005) Reg FD

Panel A: Individual Effects

Intercept	-0.095***	-0.073***	0.173***	0.246***	0.531***
	(-13.5)	(-7.91)	(18.2)	(29.2)	(29.9)
RegFD	-0.051	-0.055	-0.161	-0.005	0.067***
	(-1.64)	(-1.68)	(-5.17)	(-0.10)	(0.69)
V_{RI1}/P	0.176***				
	(12.4)				
V_{RI2}/P		0.124***			
		(7.69)			
V_{PEG}/P			-0.310***		
			(-11.2)		
LTG				-0.501***	
				(-30.4)	
REC					-0.139***
					(-33.6)
V_{RI1}/P*RegFD*	0.148***				
	(3.36)				
V_{RI2}/P*RegFD*		0.175***			
		(3.50)			
V_{PEG}/P*RegFD*			0.280***		
			(7.35)		
*LTG*RegFD*				-0.061	
				(-1.34)	
*REC*RegFD*					-0.019
					(-0.89)
Adjusted R^2	0.019	0.014	0.022	0.088	0.018

(Table 4 continued on next page)

TABLE 4 (continued)
Relation between Annual Size-adjusted Returns and Stock Recommendations and Valuation Estimates Before (1993-1999) and After (2000-2005) Reg FD

Panel B: Incremental Effects

Intercept	0.401 ***	0.452 ***	0.526 ***	0.306***
	(34.5)	(37.0)	(24.4)	(22.9)
RegFD	-0.009	0.020	0.084	0.208
	(-0.16)	(0.33)	(0.75)	(2.60)**
V_{RI1}/P	0.137 ***			
	(10.7)			
V_{RI2}/P		0.098 ***		
		(6.70)		
V_{PEG}			-0.271 ***	
			(-9.15)	
LTG				-0.490***
				(-28.2)
REC	-0.123 ***	-0.132 ***	-0.097 ***	-0.017***
	(-39.1)	(-38.2)	(-13.1)	(-4.44)
$V_{RI1}/P*RegFD$	0.166 ***			
	(4.49)			
$V_{RI2}/P*RegFD$		0.199 ***		
		(4.69)		
$V_{PEG}/P*RegFD$			0.304 ***	
			(6.54)	
*LTG*RegFD*				-0.043
				(-1.02)
*REC*RegFD*	-0.014	-0.023	-0.065 **	-0.056***
	(-1.08)	(-1.56)	(-2.26)	(-5.90)
Adjusted R^2	0.032	0.029	0.033	0.089

The table presents the results of regressions of buy-and-hold annual size-adjusted returns on valuation estimates and consensus stock recommendations. Regressions are estimated based on one-year-ahead earnings forecast horizon (i.e., months t-1 to t-12). The table presents mean coefficients for these 12 monthly regressions. t-statistics are based on the standard error of the coefficient estimates across the 12 months, adjusted for autocorrelation in the monthly coefficients based on as assumed AR(1) autocorrelation structure. Standard errors are multiplied by an adjustment factor, $\sqrt{\frac{(1+\Phi)}{(1-\Phi)} - \frac{2\Phi(1-\Phi^n)}{n(1-\Phi)^2}}$, where *n* is the number of months and Φ is the first-order autocorrelation of the monthly coefficient estimates. Adjusted R^2s presented are means across the 12 months. The regressions are estimated using quintile rankings of the independent variables. The quintile rankings are designated by allocating observations in equal numbers to quintiles within each month. The quintile rankings are scaled to range between 0 and 1 (e.g., (QUINTLE-1)/4)). *RegFD* equals 1 if an observation is from the post-Reg FD period (2000-2005) and zero otherwise (1993-1999). Other independent variables are defined in Table 1. *, **, *** reflect significance at the 0.10, 0.05, and 0.01 level, respectively, based on two-tailed t-tests.

TABLE 5
Relation between Annual Size-adjusted Returns and Stock Recommendations and Valuation Estimates Before (2000-2002) and After (2003-2005) Other Regulations (OtherReg)

Panel A: Individual Effects

Intercept	-0.160***	-0.145***	-0.051***	0.349***	0.674***
	(-18.6)	(-14.7)	(-7.2)	(7.8)	(7.2)
OtherReg	0.121***	0.143***	0.147***	-0.128	-0.190***
	(6.12)	(4.43)	(7.47)	(-1.40)	(-3.61)
V_{RI1}/P	0.344***				
	(7.47)				
V_{RI2}/P		0.329***			
		(6.19)			
V_{PEG}/P			0.005		
			(0.24)		
LTG				-0.652***	
				(-9.72)	
REC					-0.182***
					(-9.20)
V_{RI1}/P*OtherReg*	-0.054				
	(-0.65)				
V_{RI2}/P*OtherReg*		-0.083			
		(-0.76)			
V_{PEG}/P*OtherReg*			-0.102**		
			(-2.63)		
*LTG*OtherReg*				0.283*	
				(1.93)	
*REC*OtherReg*					0.074***
					(3.67)
Adjusted R^2	0.045	0.038	0.004	0.135	0.027

(Table 5 continued on next page)

TABLE 5 (continued)
Relation between Annual Size-adjusted Returns and Stock Recommendations and Valuation Estimates Before (2000-2002) and After (2003-2005) Other Regulations (OtherReg)

Panel B: Incremental Effects

Intercept	0.449 ***	0.527 ***	0.680 ***	0.620***
	(8.03)	(8.75)	(6.97)	(7.11)
OtherReg	-0.069	-0.057	-0.197 ***	-0.169
	(-0.90)	(-0.76)	(-3.68)	(-2.10)**
V_{RI1}/P	0.310 ***			
	(7.36)			
V_{RI2}/P		0.310 ***		
		(6.28)		
V_{PEG}/P			0.063 **	
			(1.96)	
LTG				-0.626***
				(-8.61)
REC	-0.151 ***	-0.168 ***	-0.191 ***	-0.072***
	(-11.6)	(-11.9)	(-7.77)	(-2.79)
V_{RI1}/P*OtherReg*	-0.017			
	(-0.20)			
V_{RI2}/P*OtherReg*		-0.037		
		(-0.37)		
V_{PEG}/P*OtherReg*			-0.100 **	
			(-2.31)	
*LTG*OtherReg*				0.281
				(1.62)
*REC*OtherReg*	0.042 *	0.042 ***	0.090 ***	0.010
	(2.02)	(2.70)	(3.96)	(0.17)
Adjusted R^2	0.063	0.061	0.029	0.142

The table presents the results of regressions of buy-and-hold annual size-adjusted returns on valuation estimates and consensus stock recommendations. Regressions are estimated based on one-year-ahead earnings forecast horizon (i.e., months t-1 to t-12). The table presents mean coefficients for these 12 monthly regressions. t-statistics are based on the standard error of the coefficient estimates across the 12 months, adjusted for autocorrelation in the monthly coefficients based on as assumed AR(1) autocorrelation structure. Standard errors are multiplied by an adjustment factor, $\sqrt{\frac{(1+\Phi)}{(1-\Phi)} - \frac{2\Phi(1-\Phi^n)}{n(1-\Phi)^2}}$, where n is the number of months and Φ is the first-order autocorrelation of the monthly coefficient estimates. Adjusted R^2s presented are means across the 12 months. The regressions are estimated using quintile rankings of the independent variables. The quintile rankings are designated by allocating observations in equal numbers to quintiles within each month. The quintile rankings are scaled to range between 0 and 1 (e.g., (QUINTLE-1)/4)). OtherReg equals 1 if an observation is in the post-other regulation period (2003-2005) and zero otherwise (2000-2002). Other variables are defined in Table 1. *, **, *** reflect significance at the 0.10, 0.05, and 0.01 level, respectively, based on two-tailed t-tests.

ABN·AMRO

February 2008

Global Investment Returns Yearbook 2008: Synopsis

A message from Rob Bate, ABN AMRO's Head of European Research:

We are proud to present the latest – the ninth – edition of the annual *Global Investment Returns Yearbook* (*GIRY*). Again, we present an updated global returns database with its unmatched breadth and historical perspective.

This year's thematic studies are about momentum, a subject of importance to all investors, whether their investment style favours it or not. We show that momentum profits in equities have been large and pervasive across time and markets, and present findings from the longest momentum study ever undertaken. We also discuss how supply and demand as well as financing mechanisms can work as important multipliers of momentum for real estate and for commodity prices. Our focus throughout is on the practical implications for investors. In short, as always with *GIRY*, we hope to stimulate an interesting and productive debate.

The Global Investment Returns Yearbook was launched in 2000. It is produced for ABN AMRO by London Business School experts Elroy Dimson, Paul Marsh and Mike Staunton, with a contributed chapter by Rolf Elgeti, ABN AMRO's former Head of Equity Strategy. This synopsis outlines the contents of the 2008 *Yearbook* and highlights some of its key findings.

The core of the *Yearbook* is provided by a long-run study covering 108 years of investment since 1900 in all the main asset categories in Australia, Belgium, Canada, Denmark, France, Germany, Ireland, Italy, Japan, the Netherlands, Norway, South Africa, Spain, Sweden, Switzerland, the United Kingdom, and the United States. These markets today make up some 85% of world equity market capitalisation. *GIRY* also reviews recent performance in a wider set of 29 markets comprising 98% of world capitalisation. With the unrivalled quality and breadth of its database, the *Yearbook* is the global authority on long-run stock, bond, bill and foreign exchange performance.

In the 2008 *Yearbook*, the authors address some of the most important questions in investment.

- **Chapter 1** analyses the performance of global markets over 2007 and over the first eight years of the current decade, highlighting what happened and why.
- **Chapter 2** provides a comprehensive update on the long-term record of stocks, bonds, bills, inflation, currencies and risk premia around the world.
- **Chapter 3** focuses on momentum in equity markets, and shows that momentum profits have been large and pervasive across time and markets, drawing on findings from the longest momentum study ever undertaken.
- **Chapter 4,** by Rolf Elgeti, develops this theme by discussing how supply and demand as well as financing mechanisms can work as important multipliers of momentum for real estate and for commodity prices.
- **Chapters 5–24** cover each of the 17 countries, plus the combined world and world ex-US indices, providing in-depth analysis for each of five asset classes spanned by the authors' 108-year history of asset returns.
- **Chapter 25** provides a bibliography.

ABN AMRO distributes the *Global Investment Returns Yearbook* to its institutional investment clients, journalists and the media. Institutional clients should contact abnamroresearch@abnamro.com. Journalists should contact Aoife Cliodhna Reynolds (aoife.cliodhna.reynolds@uk.abnamro.com).

London Business School distributes the *Yearbook* to all other users, who should contact Stefania Uccheddu (succheddu@london.edu).

ISBN 978-0-9537906-8-5. The price of the *Global Investment Returns Yearbook 2008* is £150.

250 Bishopsgate, London EC2M 4AA, United Kingdom

www.abnamroresearch.com

Overview of Chapter 1: Recent Investment Returns

The *Global Investment Returns Yearbook* starts by providing detailed statistics on, and analysing the recent performance of, equities and bonds in all the major world markets. Chapter 1 focuses on 2007 and the first eight years of this decade.

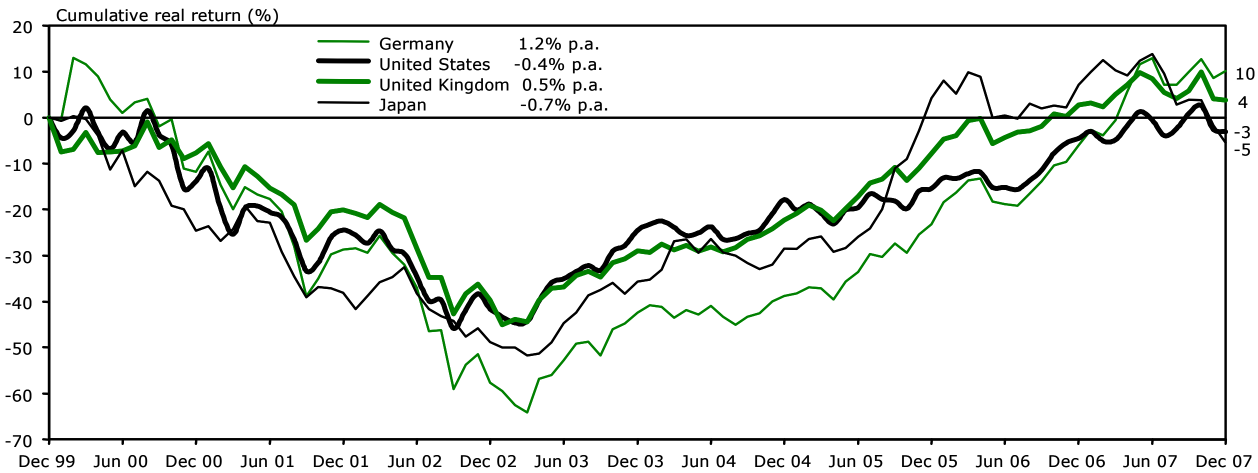
Key findings for 2007:

- Despite the turmoil in the credit markets, stock markets performed reasonably well in most countries. Emerging markets did best.
- Volatility accelerated from a low base at the start of 2007.
- Sector exposures had a larger impact than in recent years, with resource stocks doing particularly well, and financials suffering.
- The tide turned for small-caps, which suffered a reversal after four years of outperformance. Value stocks also disappointed, and they underperformed growth stocks.
- While the US (and world) bond indices did well, most government bond markets gave a negative real return.
- Commodities, notably oil, generally performed well.
- The second half of 2007 witnessed a real estate slowdown in many countries, and a sharp collapse in the US.
- Currency mattered. The US dollar was again weak, and nearly all currencies were performance enhancing. Most countries had satisfactory USD returns, but their Euro returns were markedly lower.

As Figure 1 shows, by end-2007 stock markets had largely eliminated the losses from the savage, start-of-century bear market. This is remarkable since, at the trough in March 2003, US stocks had fallen 45%, UK equity prices had halved, and German stocks had fallen by two-thirds. The *Yearbook* shows that:

- Annualised real equity returns over 2000-07 remain negative in only three of the 17 *Yearbook* countries, the US (-0.4%), Japan (-0.7%) and The Netherlands (-1.3%). However, returns remain low in several other markets, including the UK (0.5%), Germany (1.4%), France (1.2%), Italy (0.9%) and Sweden (1.4%).
- The annualised USD real return on the *GIRY* world index over 2000–07 is just 1.3%. Over this period, bonds beat equities (and bills) in 10 out of 17 countries, including all the largest markets. Realised equity risk premia over this period remain low by historical standards.

Figure 1: Equity performance in selected world markets in real, local-currency terms



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart3, Dow Jones Wilshire and Thomson Financial Datastream

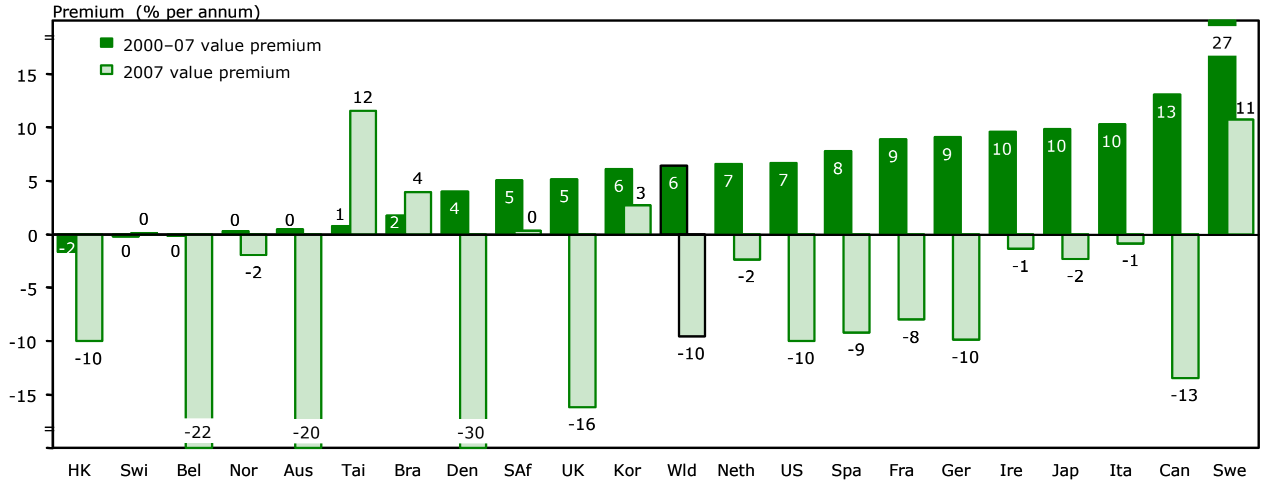
In recent years, there have been remarkable shifts worldwide in relative performance according to size, style and sector. The *Yearbook* documents and analyses these factors to shed light on the underlying causes of performance.

Findings over 2000-07 include:

- Despite 2007 being generally disappointing for small-caps, over 2000–07 they nevertheless beat large-caps in every *Yearbook* country except Norway (and, marginally, Taiwan). In most countries, those who invested in 2000 in small-caps are more than 50% richer than large-cap investors.

- The poor return in 2007 from value stocks did not eliminate the 2000-07 value premium. Figure 2 reports the value premium: the performance of value stocks relative to growth stocks. It shows that, over 2000-07, value stocks beat growth stocks in every *Yearbook* country except Hong Kong (and, marginally, Switzerland). In most markets, those who invested in 2000 in value stocks are more than 50% richer than growth-stock investors.

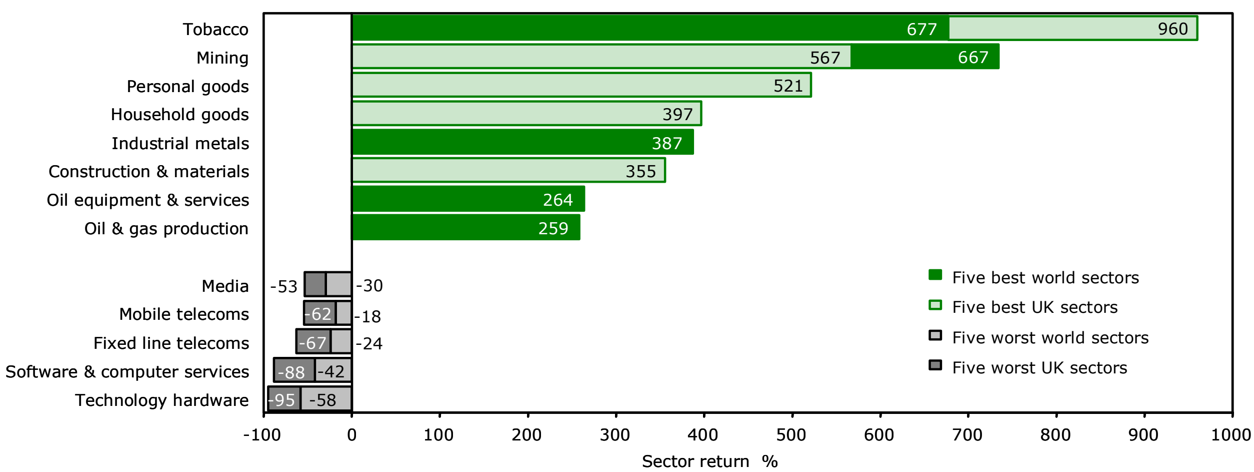
Figure 2: Value-growth premia around the world during 2007 and 2000–08



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart7 and MSCI style-based indices

- Momentum trading has provided large potential profits in virtually every equity market. A strategy of buying stock market winners, while avoiding (or taking a short position in) stocks that have performed poorly, has provided a large premium since 2000-07. We also analyse momentum investing, in detail, in Chapter 3.
- A major factor is the investor's choice of reference currency. Over the eight years since 2000, the US dollar has fallen against all *Yearbook* currencies except two (the South African Rand and the Yen). Since 2002, the dollar has fallen against every *Yearbook* currency—by 39% in the case of the Euro.
- A huge gap has now opened up in sector performance since the tech-bubble burst in March 2000. Figure 3 highlights the best and worst performing sectors, showing that an investment in the top performing UK sector—tobacco—would now be worth 212 times more than an equivalent amount invested in the worst performing sector—technology hardware.

Figure 3: Returns on best and worst performing sectors from mid-March 2000 until end-2007



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, Chart 5 and Nomura/FTSE International All-World Review

Chapter 1 delves into what happened in 2007 and over 2000-07, and why. The authors dissect the sources of global returns, revealing whether performance reflects skill, luck, or a combination of the two. While *GIRY* may inadvertently serve the "market for excuses", its main aim is to help investors diagnose the market exposures that can enhance or hinder performance.

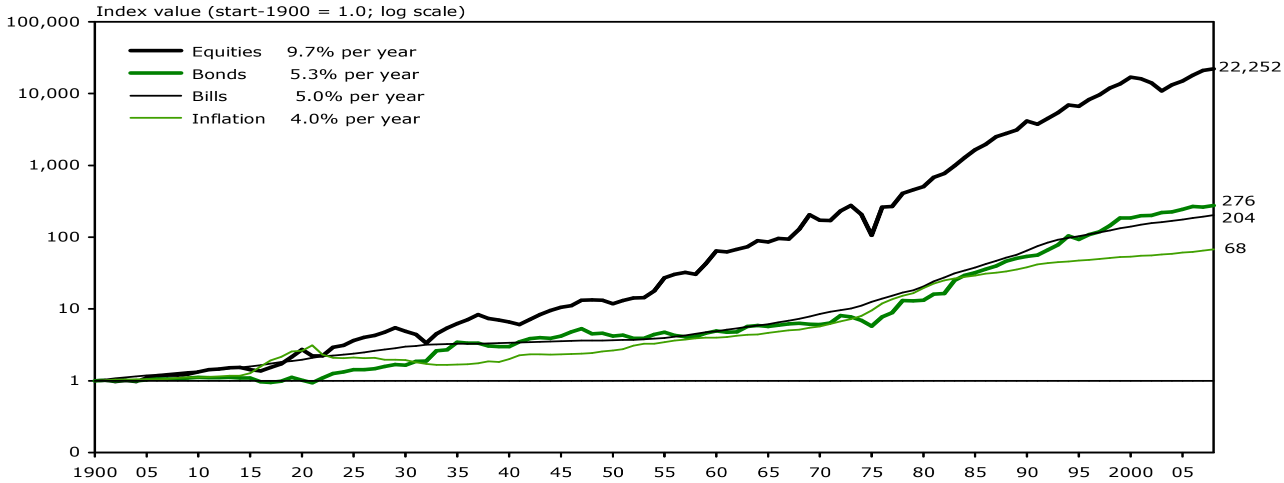
One—or even eight—years is a brief interval in investment. To form a meaningful judgement about the future we need to look not only at the recent past, but also at the long run. That is the subject of Chapter 2, which provides a comprehensive global analysis of the long-term record of stocks, bonds, bills, inflation, currency and risk premia.

Overview of Chapter 2: The Long-Run Perspective

Chapter 2 presents long-run evidence on asset returns over 108 years, and on stock market anomalies such as the size effect and the performance of value investing. Key findings are that:

- An investment in UK equities of £100 at the start of 1900 would, with dividends reinvested, have grown to over £2.2 million by the end of 2007, a return of 9.7% p.a. (see Figure 4). Long bonds and treasury bills gave lower annualised returns of 5.3% and 5.0%, respectively, although they beat inflation (4.0%).

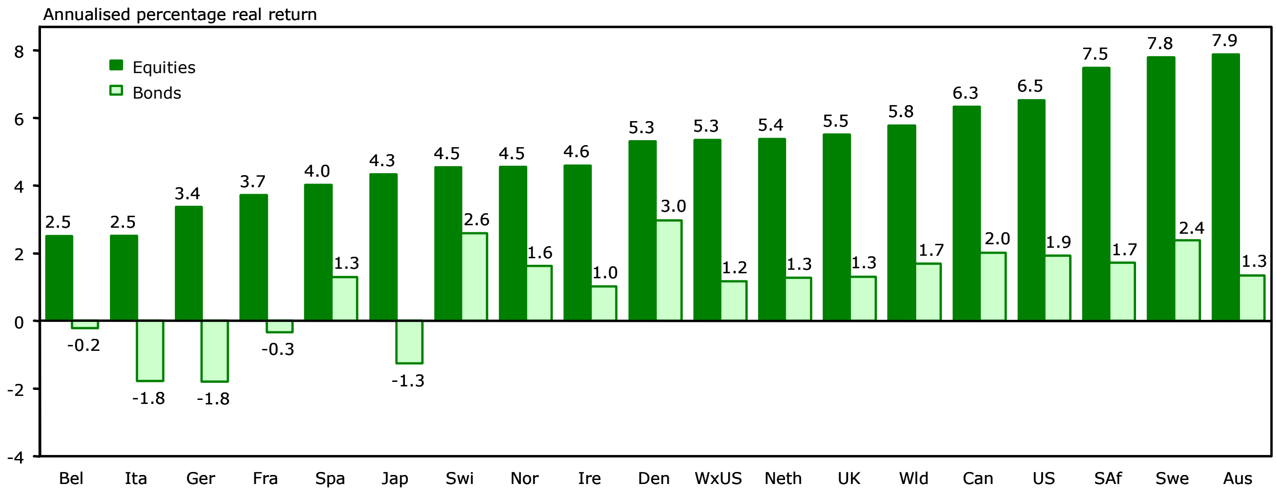
Figure 4: Cumulative returns on UK asset classes in nominal terms, 1900—2007



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart 12

- The *Yearbook* provides charts similar to Figure 4, in both nominal and real terms, for all 17 countries plus the world and world ex-US indices (see the summary of chapters 5–24 below). They show that since 1900, equities are the best-performing asset class in every country, while bonds beat bills everywhere except Germany.
- Figure 5 shows that the best performing equity markets over the very long term are Australia and Sweden, with annualised real returns since 1900 of 7.9% and 7.8%, respectively, compared to a world average of 5.8%.

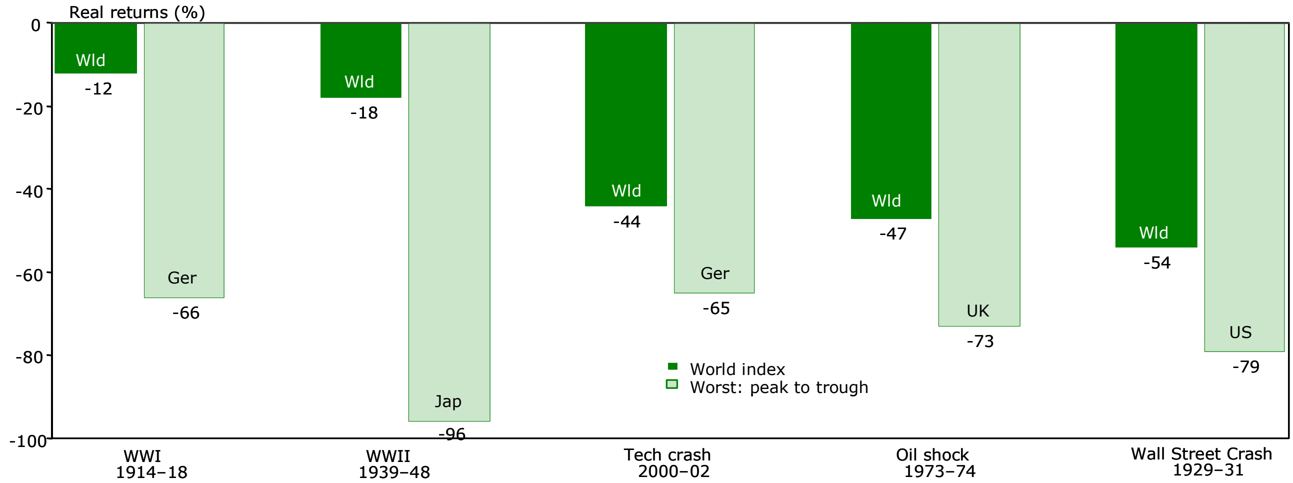
Figure 5: Real returns on equities versus bonds internationally, 1900—2007



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart 14

- Equity returns were subject to considerable volatility. The UK's standard deviation of 19.8% places it alongside the US (20.0%) at the lower end of the risk spectrum. The highest volatility markets were Germany (32.3%), Japan (29.8%), and Italy (28.9%), reflecting the impact of wars and inflation.
- In contrast to the volatility levels of individual markets, the *GIRY* world portfolio has a standard deviation of just 17.1%, showing the risk reduction obtained from international diversification.
- History has witnessed several episodes of extreme losses for equities. Figure 6 shows that the three great bear markets inflicted far more damage on world equities than the world wars. Note that in each episode of turbulence, the losses experienced in the worst affected market were very large indeed.

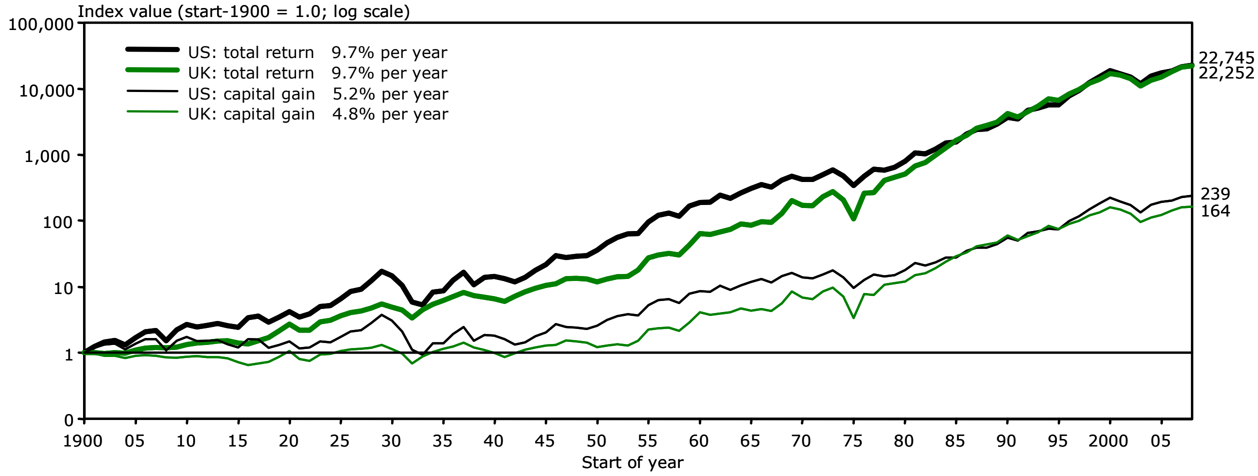
Figure 6: Extremes of equity market history, 1900-2007



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, Table 6

- Chapter 2 shows that over the long run, small-caps have outperformed in most countries. Similarly, value stocks have beaten growth stocks. When these factors are analysed together, small-value did best of all.
- Long-run returns are heavily influenced by reinvested dividends. After 108 years, $1 invested in US equities in 2000 would have grown to $22,745 with dividends reinvested, but to just $239 on a capital gains only basis.

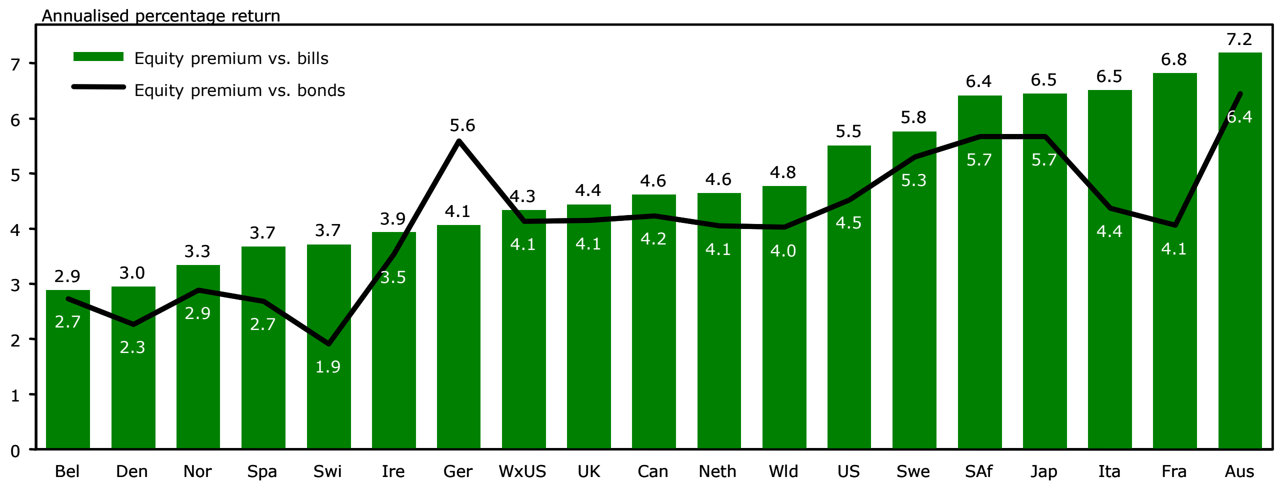
Figure 7: Impact of reinvested dividends on cumulative UK & US equity local-currency returns, 1900—2007



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart 18

- Figure 8 shows the annualised (geometric) equity risk premia realised over the last 108 years.

Figure 8: Worldwide annualised equity risk premia relative to bonds and bills, 1900—2007



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart 20

- The equity risk premium is the difference in performance between equities and bills (or bonds). As can be seen in Figure 8, from 1900–2007 the annualised equity risk premium relative to bills was 5.5% for the US, 4.4% for the UK, and 4.8% for the world index—somewhat lower than was previously believed.
- The authors' latest research, just published in 2008, decomposes historical returns into four components. They are the historical dividend yield, dividend growth, re-rating, and real currency movements. Chapter 2 of the *Yearbook* provides a breakdown of these components for all 17 countries and the world index.
- Drawing on their analysis, the London Business School team estimate that a plausible, forward-looking risk premium for the world's major markets would be around 3–3½% relative to bills on a geometric mean basis. The corresponding arithmetic mean risk premium is around 5% (references are at the end of this synopsis).

Overview of Chapter 3: Momentum in the Stock Market

Momentum, or the tendency for stock returns to trend in the same direction, is a major puzzle. In well-functioning markets, it should not be possible to make money from simply buying past winners and selling past losers. Yet Chapter 3 provides extensive evidence, across time and markets, that momentum profits have been large and pervasive. This evidence comes both from previous studies and from unique new London Business School research.

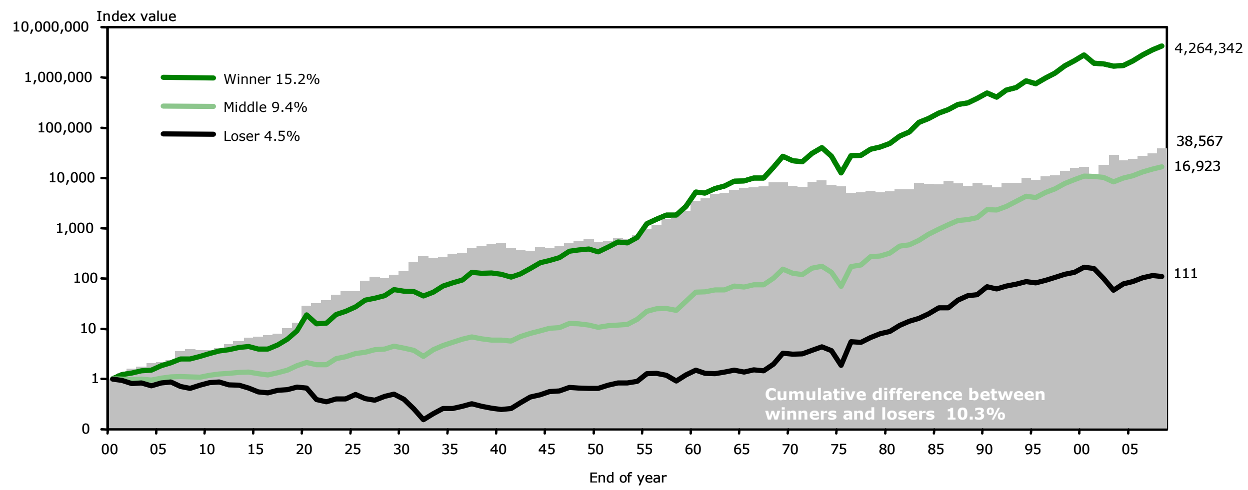
Momentum matters because most investors have styles that favour, or conflict, with momentum. Those "following" momentum include many hedge funds, quant strategies and growth investors. Practices like letting winners run or cutting losses also implicitly play to momentum. However, value investors, small-cap funds and contrarians tend to suffer from momentum. Whatever their style, momentum is highly relevant to all investors.

Pure momentum strategies involve ranking stocks into winners and losers based on past returns over a *ranking period*. One then buys the winners and short-sells the losers, over a *holding period*. To ensure implementability, there is usually a *wait period* before investing. Strategies are thus described as "**r**/**w**/**h**". For example, a 12/1/1 strategy **r**anks returns over the past 12 months, **w**aits 1 month, and then **h**olds for 1 month until rebalancing.

Key findings of Chapter 3 include:

- Winners (defined as the top 20% past returns) beat losers (bottom 20%) by 10.8% per year across the entire UK equity market from 1956–2007 (the period for which comprehensive data is available).
- With equal, rather than capitalisation, weights, the difference was even greater at 12.0%. And with winners/losers defined as the top/bottom 10% (rather than 20%), the gap was greater still.
- The winner-minus-loser (WML) gap was smaller at 7.0% p.a. when investment was limited to just the Top 100 UK stocks. However, within this group of highly liquid stocks, the strategy was much easier to implement.
- In the longest momentum study ever conducted, covering the Top 100 stocks over 108 years, Figure 9 shows that winners beat losers by 10.3% per year. £1 invested at start-1900 in the winner portfolio would have grown to more than £4¼ million (15.2% p.a.). £1 invested in the losers would have grown to only £111 (4.5% p.a.).

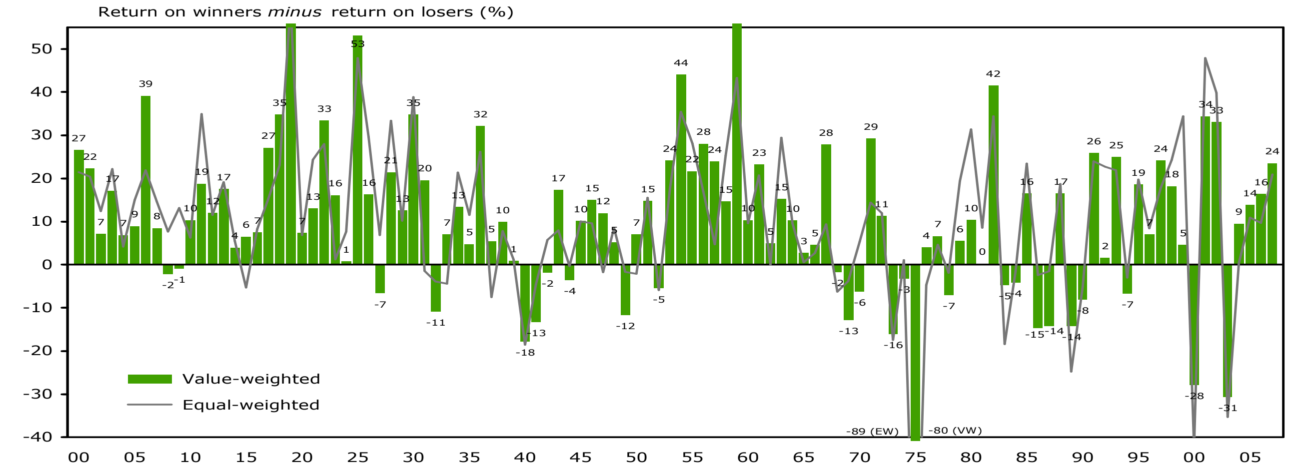
Figure 9: Annual value-weighted momentum portfolio returns for the Top 100 UK equities 1900-2007



This chart shows value-weighted returns for winner and loser portfolios among the Top 100 equities, defined with breakpoints at the 20th and 80th percentiles. The shaded area is the cumulative difference between winners and losers, and measures the value of a long-short WML portfolio. The momentum process followed here is a 12/1/1 strategy. Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart 26

- Stock market research always needs a holdout period—to check whether the effect persists over a period other than the one used to "discover" it. The 108-year study uses the longest holdout period ever—56 years of virgin data from 1900–55, collected especially for *GIRY*. Momentum proved even stronger over this holdout period.
- Momentum returns were remarkably robust to the choice of ranking period, holding period, weighting scheme, definition of winners, and choice of sample. All strategies achieved a high level of statistical significance.
- However, there are important caveats. First, as Figure 10 shows, there are numerous periods when winners underperform losers, sometimes by a dramatic margin. Pure momentum plays are not for the faint hearted.

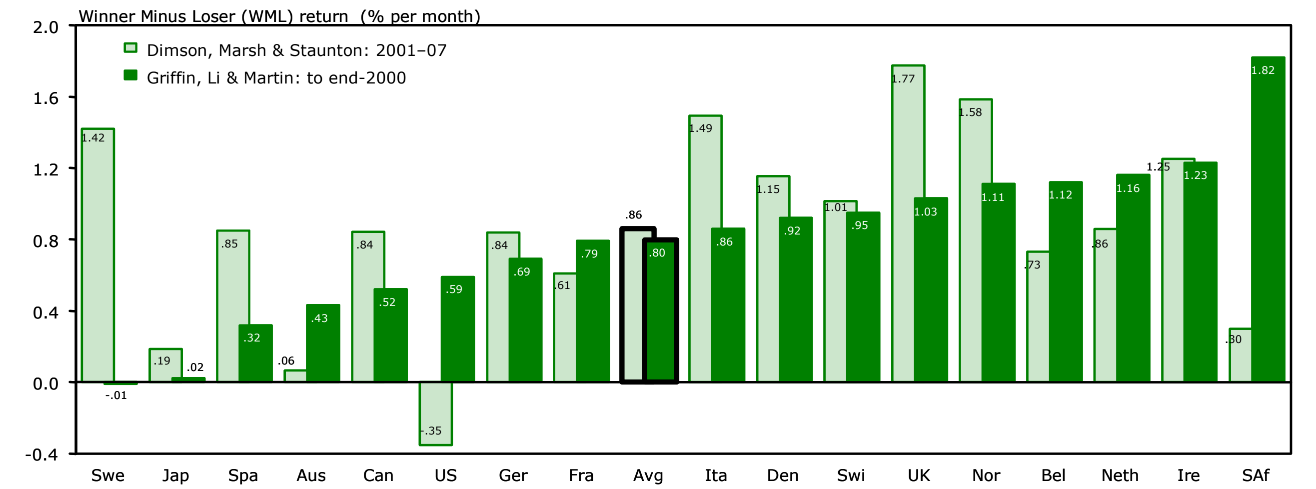
Figure 10: Return on winners minus losers for Top 100 UK equities, annually 1900-2007



This chart shows value-weighted WML returns based on portfolios with momentum breakpoints at the 20th and 80th percentiles. The momentum process followed here is a 12/1/1 strategy. Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart 27

- Second, turnover can be very high, especially with monthly rebalancing. For the 12/1/1 strategy, winner and loser turnover averages 31% and 33% per month. Transactions costs can seriously dent performance.
- Chapter 3 also presents up-to-date evidence on worldwide momentum covering 33 years for most *GIRY* markets. The dark bars in Figure 11 show that the average WML return in the 17 *GIRY* countries was 0.80% per month up to end-2000, as estimated by Griffin, Ji, and Martin (*Journal of Finance*, 2003).
- The light bars in Figure 11 show the equivalent returns from 2001–07. Over this "holdout" period, the average monthly return was even higher at 0.86%. The US was the only market for which WML returns were negative.

Figure 11: Monthly momentum returns in 17 stock markets, up to 2000 and 2001–2007



This chart shows the winner-minus-loser (WML) return from a 6/1/6 momentum strategy, following the methodology described in Griffin, Ji and Martin (2003). The breakpoints are the 20th and 80th percentiles. The Griffin, Ji and Martin sample period begins in 1975 (or, for a few countries, a different year) and ends in 2000. The subsequent period runs from start-2001 to end-2007. Data is from the LSPD (for the UK) and Datastream (other countries). Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, chart 29, Griffin, Ji and Martin (2003) and Thomson Financial Datastream.

The authors, Elroy Dimson, Paul Marsh and Mike Staunton of London Business School, conclude: "The momentum effect, both in the UK and globally, has been pervasive and persistent. Though costly to implement on a stand-alone basis, all investors need to be acutely aware of momentum. Even if they do not set out to exploit it, momentum is likely to be an important determinant of their investment performance."

Overview of Chapter 4: Momentum in Real Estate

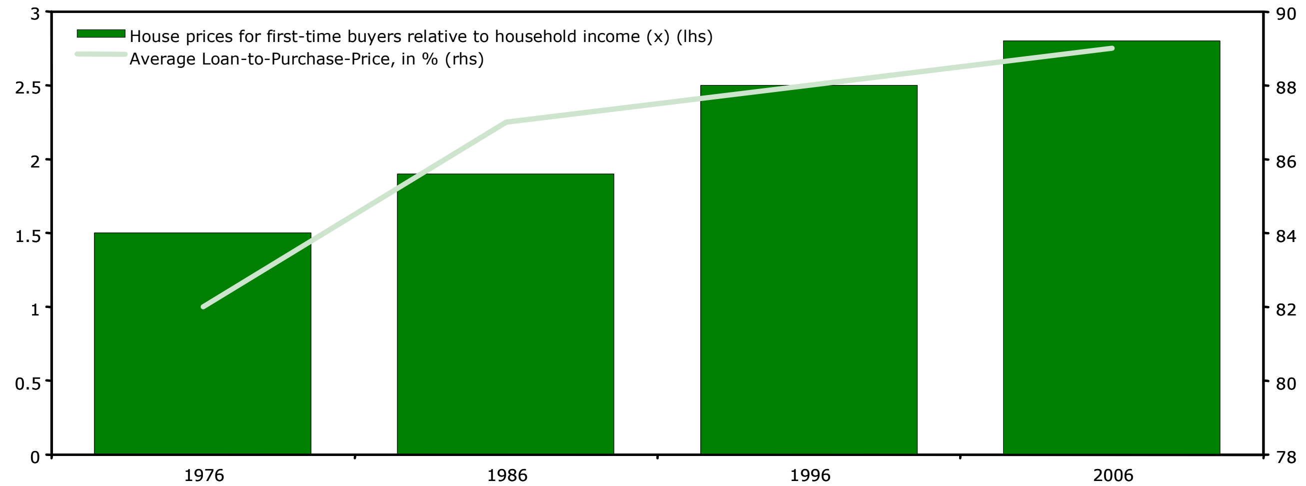
Momentum has become an important factor in many markets. In addition to equities, the *Yearbook* looks at other asset classes. An illiquid asset, like real estate, is more vulnerable to price momentum because of the time delays between transactions. In Chapter 4, Rolf Elgeti discusses momentum in real estate.

Elgeti's starting point is that investors are drawn to assets that go up in price, and that momentum is driven not only by buyers and sellers, but also by third parties who intervene in the market and affect supply and demand. This includes:

- Mortgage banks, which behave pro-cyclically, strengthening momentum in real estate – in either direction.
- First-time buyers, the number of whom rises in a buoyant market, even though affordability may actually worsen. Again, this reinforces momentum, creating a gradual structural change in the demand-pull of the market.
- House builders, who might be expected to increase the housing supply when prices rise and to stop when prices fall, but whose response can be untimely and with considerable regional differences.

In Figure 12, Elgeti examines the US market, noting how a small change in banking policy can influence what people pay for their first house. Over the past 30 years, US mortgage banks increased lending to first-time buyers from an average 82% (in 1976) to 89% (in 2006). The 7 percentage points of increased leverage resulted in first-time buyers paying much more: about 2.75x their income in 2006, versus about 1.5x their annual income in 1976.

Figure 12: Affordability and LTVs for first-time buyers in the US



Source: Federal Reserve Bank of Chicago

If banks were acting counter-cyclically, they would argue, "When houses cost about 1.5 times income we lent 82%; now they cost nearly 3 times their income risk is higher, so we should lend less." But the opposite has been the case, and banks raised their loan-to-purchase-price ratios, despite houses becoming not only more expensive but less affordable. Banks' behaviour thereby accentuates momentum in real estate prices.

Elgeti also offers evidence to support his claims in relation to first-time buyers and house-builders, drawing evidence from a number of countries. He notes similar momentum effects that may be found in other markets, such as commodities.

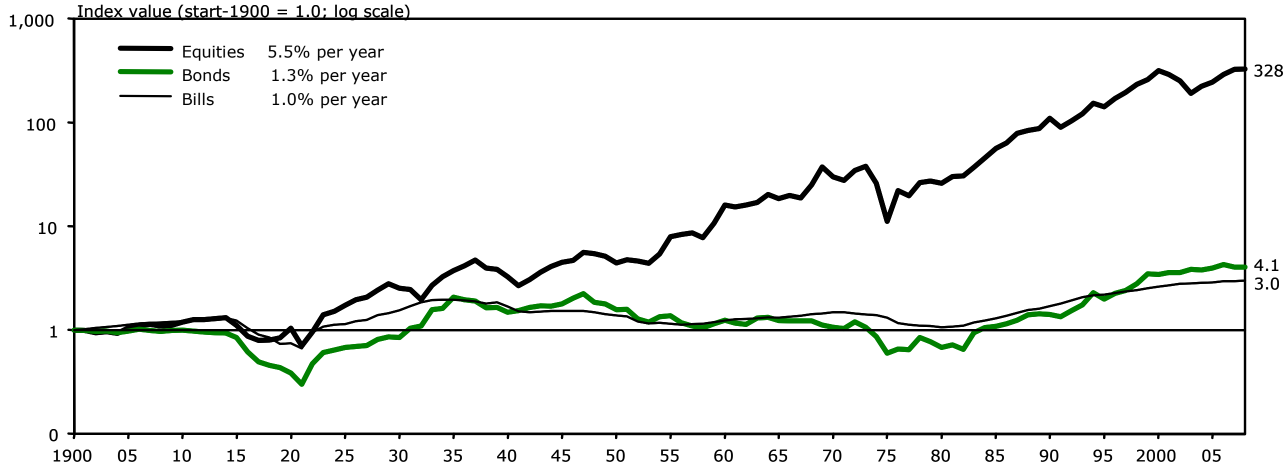
Overview of Chapters 5–24: Individual Markets

These chapters present detailed in-depth statistical analysis of the performance of each of five asset classes in each of the 17 *GIRY* countries over the full 108-year history from 1900–2007. Chapter 5 provides an introduction to the country Chapters. Chapters 6–22 then cover each country in turn, while Chapters 23 and 24 provide equivalent statistics for the combined world ex-US and world indices. Each country chapter contains:

- An introductory section describing the authors' data sources.
- A summary table, providing an overview of asset returns and risk premia for that country.

- Charts portraying both the cumulative returns, and the year-to-year returns for each country in both nominal terms (Figure 4 above) and real terms (Figure 13).

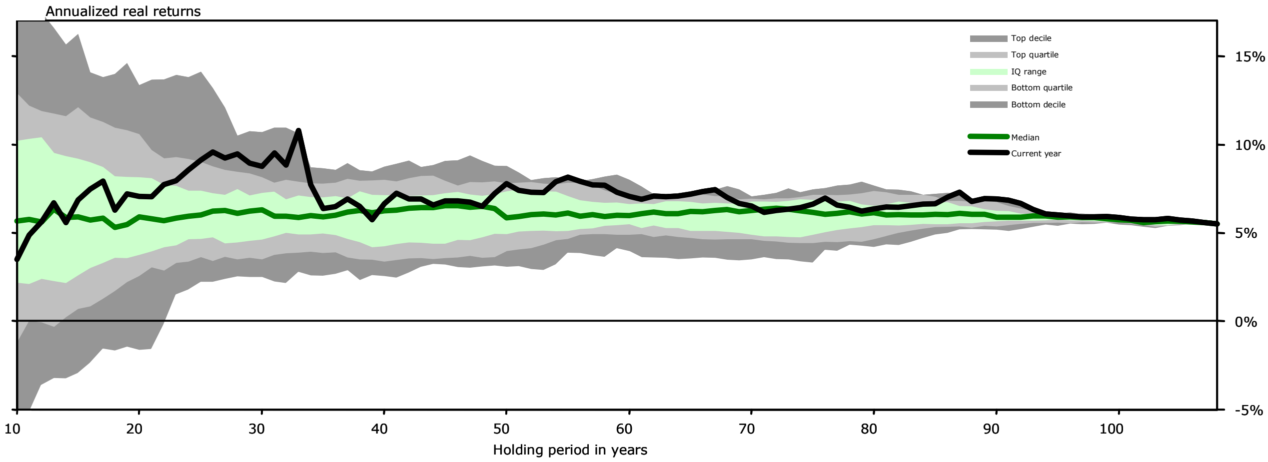
Figure 13: Cumulative returns on UK asset classes in real terms, 1900—2007



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, charts 13 and 117

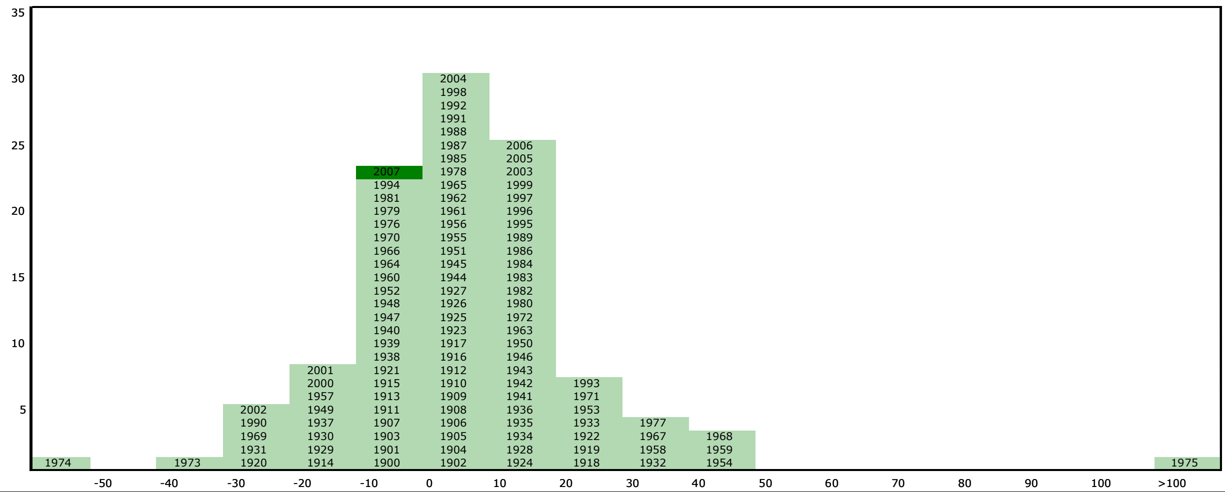
- Charts depicting the dispersion of returns over investment horizons of between 10 and 108 years (Figure 14).
- Histograms showing the distribution of annual risk premia (Figure 15)

Figure 14: Dispersion of real returns on UK equities over periods of 10-108 years



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, charts 119

Figure 15: UK equity risk premium relative to bills



Source: ABN AMRO/LBS Global Investment Returns Yearbook 2008, charts 121

- Tables of annualised return "triangles". The tables present returns over individual and multiple decades, and returns to date from an initial investment made at the start of 1900, 1910, and so on to the start of 2000. They cover each of the four asset categories in real terms (as well as real equity capital gains); the three risk premia relating to equities, bonds and bills; the real and nominal exchange rates against the dollar; and the annualised inflation rate, over all periods of 1, 2,...,10 decades.
- Tables listing index levels and returns for all the asset series in nominal and real terms, with index values provided at intervals of one decade from 1900 to 2000, and thereafter on an annual basis.

Further information

Further information on long run rates of return is provided in Elroy Dimson, Paul Marsh and Mike Staunton's book, *Triumph of the Optimists* (published by Princeton University Press, 2002). The authors have also analysed the equity risk premium, the long-run risks of equity investment, international diversification and many other strategic issues in investment.

Their most recent research, exploring more aspects of the Yearbook data, is published in *Financial Analysts Journal*, *Journal of Portfolio Management*, and *Journal of Applied Corporate Finance*. Their latest paper, The Worldwide Equity Premium: A Smaller Puzzle, is in Rajnish Mehra (Ed.) *Handbook of the Equity Risk Premium* (Elsevier, 2008). It is available at http://papers.ssrn.com/id=891620 (free download).

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ABN AMRO distributes the *Global Investment Returns Yearbook 2008* to its institutional investment clients, journalists and the media. Institutional clients should contact abnamroresearch@abnamro.com.

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Earnings Growth: The Two Percent Dilution

William J. Bernstein and Robert D. Arnott

Two important concepts played a key role in the bull market of the 1990s. Both represent fundamental flaws in logic. Both are demonstrably untrue. First, many investors believed that earnings could grow faster than the macroeconomy. In fact, earnings must grow slower than GDP because the growth of existing enterprises contributes only part of GDP growth; the role of entrepreneurial capitalism, the creation of new enterprises, is a key driver of GDP growth, and it does not contribute to the growth in earnings and dividends of existing enterprises. During the 20th century, growth in stock prices and dividends was 2 percent less than underlying macroeconomic growth. Second, many investors believed that stock buybacks would permit earnings to grow faster than GDP. The important metric is not the volume of buybacks, however, but net buybacks—stock buybacks less new share issuance, whether in existing enterprises or through IPOs. We demonstrate, using two methodologies, that during the 20th century, new share issuance in many nations almost always exceeded stock buybacks by an average of 2 percent or more a year.

The bull market of the 1990s was largely built on a foundation of two immense misconceptions. Whether their originators were knaves or fools is immaterial; the errors themselves were, and still are, important. Investors were told the following:

1. With a technology revolution and a "new paradigm" of low payout ratios and internal reinvestment, earnings will grow faster than ever before. Real growth of 5 percent will be easy to achieve.

Like the myth of Santa Claus, this story is highly agreeable but is supported by neither observable current evidence nor history.

2. When earnings are not distributed as dividends and not reinvested into stellar growth opportunities, they are distributed back to shareholders in the form of stock buybacks, which are a vastly preferable way of distributing company resources to the shareholders from a tax perspective.

William J. Bernstein is principal at Efficient Frontier Advisors, LLC, Eastford, Connecticut. Robert D. Arnott is chairman of First Quadrant, LP, and Research Affiliates, LLC, Pasadena, California.

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True, except that over the long term, net buybacks (that is, buybacks minus new issuance and options) have been reliably negative.

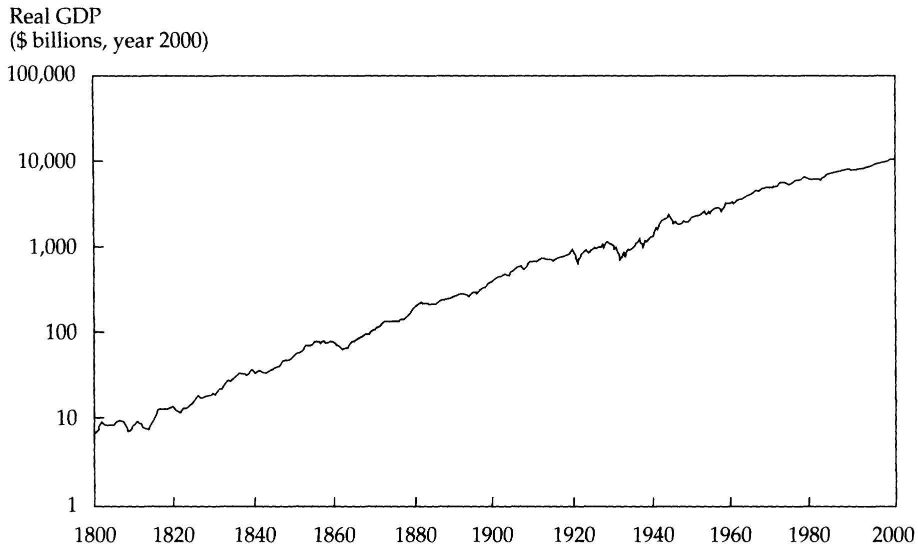
The vast majority of the institutional investing community has believed these untruths and has acted accordingly. Whether these tales are lies or merely errors, our implied indictment of these misconceptions is a serious one—demanding data. This article examines some of the data.

Big Lie #1: Rapid Earnings Growth

In the past two centuries, common stocks have provided a sizable risk premium to U.S. investors: For the 200 years from 1802 through 2001 (inclusive), the returns for stocks, bonds, and bills were, respectively, 8.42 percent, 4.88 percent, and 4.21 percent. In the most simplistic terms, the reason is obvious: A bill or a bond is a promise to pay interest and principal, and as such, its upside is sharply limited. Shares of common stock, however, are a claim on the future dividend stream of the nation's businesses. While the investor in fixed-income securities is receiving a modest fixed trickle from low-risk securities, the shareholder is the beneficiary of the ever-increasing fruits of innovation-driven economic growth.

Viewed over the decades, the powerful U.S. economic engine has produced remarkably steady growth. **Figure 1** plots the real GDP of the United States since 1800 as reported by the U.S. Department

Figure 1. Real U.S. GDP Growth, 1800–2000



of Commerce. From that year to 2000, the economy as measured by real GDP, averaging about 3.7 percent growth a year, has grown a thousandfold. The long-term uniformity of economic growth demonstrated in Figure 1 is both a blessing and a curse. To know that real U.S. GDP doubles every 20 years is reassuring. But it is also a dire warning to those predicting a rapid acceleration of economic growth from the computer and Internet revolutions. Such extrapolations of technology-driven increased growth are painfully oblivious to the broad sweep of scientific and financial history, in which innovation and change are constant and are neither new to the current generation nor unique.

The impact of recent advances in computer science pales in comparison with the technological explosion that occurred between 1820 and 1855. This earlier era saw the deepest and most far reaching technology-driven changes in everyday existence ever seen in human history. The changes profoundly affected the lives of those from the top to the bottom of the social fabric in ways that can scarcely be imagined today. At a stroke, the speed of transportation increased tenfold. Before 1820, people, goods, and information could not move faster than the speed of the horse. Within a generation, journeys that had previously taken weeks and months involved an order of magnitude less time, expense, danger, and discomfort. Moreover, important information that previously required the same long journeys could now be transmitted instantaneously.

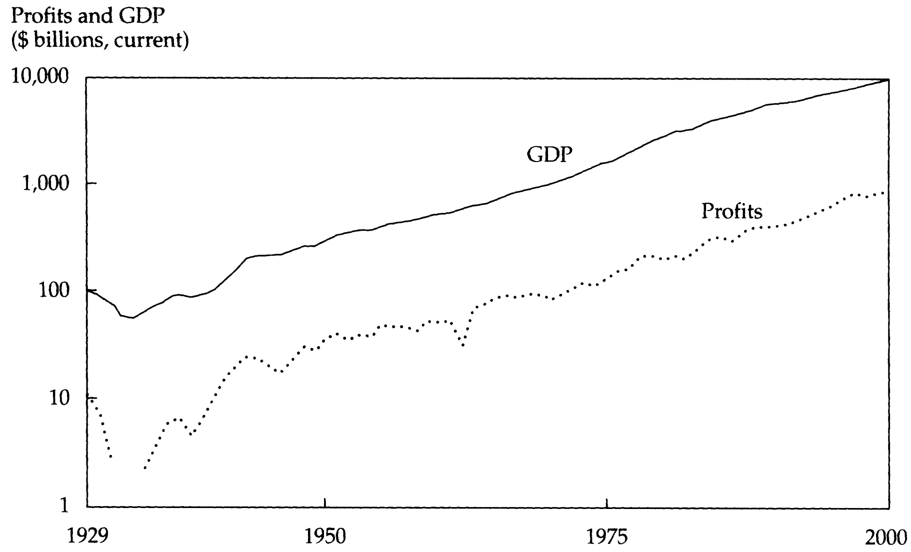
The average inhabitant of 1820 would have found the world 35 years later incomprehensible, whereas a person transported from 1967 to 2002 would have little trouble understanding the intervening changes in everyday life. From 1820 to 1855, the U.S. economy grew sixfold, four times the growth seen in the "tech revolution" of the past 35 years. More importantly, a close look at the right edge of Figure 1—the last decade of the 20th century—shows that the acceleration in growth during the "new paradigm" of the tech revolution of the 1990s was negligible when measured against the broad sweep of history.

The relatively uniform increase in GDP shown in Figure 1 suggests that corporate profits experienced a similar uniformity in growth. And, indeed, **Figure 2** demonstrates that, except for the Great Depression, during which overall corporate profits briefly disappeared, nominal aggregate corporate earnings growth has tracked nominal GDP growth, with corporate earnings remaining constant at 8–10 percent of GDP since 1929. The trend growth in corporate profits shown in Figure 2 is nearly identical, within a remarkable 20 bps, to the trend growth in GDP.[1]

Cannot stock prices also, then, be assumed to grow at the same rate as GDP? After all, a direct relationship between aggregate corporate profits and GDP has existed since at least 1929. The problem with this assumption is that per share earnings and dividends keep up with GDP *only if* no new shares are created. Entrepreneurial capitalism, however, creates a "dilution effect" through new enterprises and new stock in existing enterprises. So, per share earnings and dividends grow considerably slower than the economy.

In fact, since 1871, real stock prices have grown at 2.48 percent a year—versus 3.45 percent a year for GDP. Despite rising price–earnings ratios, we observe a "slippage" of 97 bps a year between stock

Figure 2. Nominal U.S. Corporate Profits and GDP, 1929–2000



prices and GDP. The true degree of slippage is much higher because almost half of the 2.48 percent rise in real stock prices after 1871 came from a substantial upward revaluation. The highly illiquid industrial stocks of the post–Civil War period rarely sold at more than 10 times earnings; often, they sold for multiples as low as 3 or 4 times earnings. These closely held industrial stocks gave way to instantly and cheaply tradable common shares, which today are priced nearly an order of magnitude more dearly.

Until the bull market of 1982–1999, the average stock was valued at 12–16 times earnings and 20–25 years' worth of dividends. By the peak of the bull market, both figures had tripled. Although the bull market was compressed into 18 years of the total period under discussion, this tripling of valuation levels was worth almost 100 bps a year—even when amortized over the full 130-year span. Thus, per share earnings and dividends grew 2 percent a year slower than the macroeconomy. If aggregate earnings and dividends grew as quickly as the economy while per share earnings and dividends were growing at an average of 2 percent a year slower, then shareholders have seen a slippage or dilution of 2 percent a year in the per share growth of earnings and dividends.

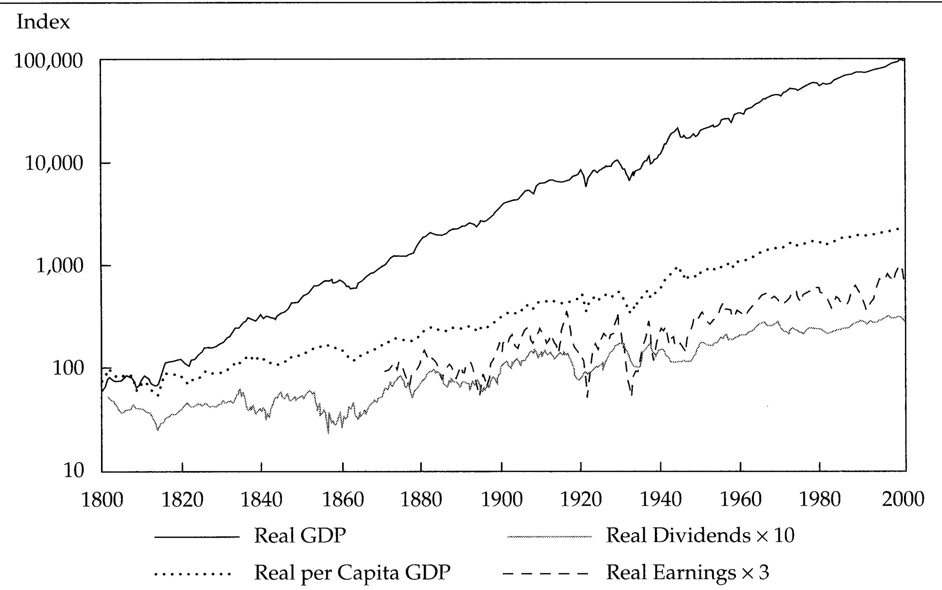
The dilution is the result of the net creation of shares as existing and new companies capitalize their businesses with equity. An often overlooked, but unsurprising, fact is that more than half of aggregate economic growth comes from new ideas and the creation of new enterprises, not from the growth of established enterprises. Stock investments can participate only in the growth of established businesses; venture capital participates only in the new businesses. The same investment capital cannot be simultaneously invested in both.

"Intrapreneurial capitalism," or the creation of new enterprises within existing companies, is a sound engine for economic growth, but it does not supplant the creation of new enterprises. Nor does it reduce the 2 percent gap between economic growth and earnings and dividend growth.

Note also that earnings and dividends grow at a pace very similar to that of per capita GDP (with some slippage associated with the "entrepreneurial" stock rewards to management). Consider that per capita GDP is a measure of productivity (with slight differences for changes in the work force) and aggregate economic wealth per capita can grow only in close alignment with productivity growth. Productivity growth is also the key driver of per capita income and of per share earnings and dividends. Accordingly, no one should be surprised that *per capita GDP, per capita income, per share earnings, and per share dividends—all grow in reasonably close proportion to productivity growth.*

If earnings and dividends grow faster than productivity, the result is a migration from return on labor to return on capital; if earnings and dividends grow more slowly, by a margin larger than the stock awards to management, then the economy migrates from rewarding capital to rewarding labor. Either way, such a change in the orientation of the economy cannot continue indefinitely. **Figure 3** demonstrates the close link between the growth of real corporate earnings and dividends and the growth of real per capita GDP; note that all of these measures exhibit growth far below the growth of real GDP.

Figure 3. Link of U.S. Earnings and Dividends to Economic Growth, 1802–2001



Note: Real GDP, real per capita GDP, and real stock prices were all constructed so that the series are on a common basis of January 1802 = 100.

A Global Laboratory

Is the United States unique? For an answer, we compared dividend growth, price growth, and total return with data on GDP growth and per capita GDP growth for the 16 countries covered by Dimson, Marsh, and Staunton (2002) spanning the 20th century.[2] The GDP data came from Maddison's (1995, 2001) world GDP survey for 1900–1998 and International Finance Corporation data for 1998–2000. The interrelationships of the data shown in **Table 1** are complex:

- The first column contains the real return (in U.S. dollars) of each national stock market.
- The second is real per share dividend growth.
- The third is real aggregate GDP growth for each nation (measured in U.S. dollars).
- The fifth is growth of real per capita GDP (measured in U.S. dollars).
- Thus, the fourth column measures the gap between growth in per share dividends and aggregate GDP—an excellent measure of the leakage that occurs between macroeconomic growth and the growth of stock prices.
- The last column represents the gap between the growth in per share dividends and per capita GDP.

For the full 16-nation sample in Table 1, the average gap between dividend growth and the growth in aggregate GDP is a startling 3.3 percent. The annual shortfall between dividend growth and per capita GDP growth is still 2.4 percent.

The 20th century was not without turmoil. Therefore, we divided the 16 nations into two groups according to the degree of devastation visited upon them by the era's calamities. The first group suffered substantial destruction of the countries' productive physical capital at least once during the century; the second group did not.

The nine nations in Group 1—Belgium, Denmark, France, Germany, Italy, Japan, the Netherlands, Spain, and the United Kingdom—were devastated by one or both of the two world wars or by civil war. The remaining seven—Australia, Canada, Ireland, South Africa, Sweden, Switzerland, and the United States—suffered relatively little direct damage. Even in this fortunate group, Table 1 shows dividend growth that is 2.3 percent less than GDP growth and 1.1 percent less than per capita GDP growth, on average. These gaps are close to the 2.7 percent and 1.4 percent figures observed in the United States during the 20th century.

The data for nations that were devastated during World Wars I and II and the Spanish Civil War are even more striking: The good news is that the economies in Group 1 repaired the devastations wrought by the 20th century; they enjoyed overall GDP growth and per capita GDP growth that rivaled the growth of the less-scarred Group 2 nations. The bad news is that the same cannot be said for per share equity performance; a 4.1 percent slippage occurred between the growth of their economies and per share corporate payouts. The

Table 1. Dilution of GDP Growth as It Flows Through to Dividend Growth: 16 Countries, 1900–2000

Country	Constituents of Real Stock Returns: Real Return	Constituents of Real Stock Returns: Dividend Growth	Real GDP Growth	Dilution in Dividend Growth (vis-à-vis GDP growth)	Real per Capita GDP Growth	Dilution in Dividend Growth (vis-à-vis per capita GDP growth)
Australia	7.5%	0.9%	3.3%	–2.4%	1.6%	–0.7%
Belgium	2.5	–1.7	2.2	–3.9	1.8	–3.5
Canada	6.4	0.3	4.0	–3.7	2.2	–1.9
Denmark	4.6	–1.9	2.7	–4.6	2.0	–3.9
France	3.6	–1.1	2.2	–3.3	1.8	–2.9
Germany	3.6	–1.3	2.6	–3.9	1.6	–2.9
Ireland	4.8	–0.8	2.3	–3.1	2.1	–2.9
Italy	2.7	–2.2	2.8	–5.0	2.2	–4.4
Japan	4.2	–3.3	4.2	–7.5	3.1	–6.4
Netherlands	5.8	–0.5	2.8	–3.3	1.7	–2.2
South Africa	6.8	1.5	3.4	–1.9	1.2	0.3
Spain	3.6	–0.8	2.7	–3.5	1.9	–2.7
Sweden	7.6	2.3	2.5	–0.2	2.0	0.3
Switzerland	5.0	0.1	2.5	–2.4	1.7	–1.6
United Kingdom	5.8	0.4	1.9	–1.5	1.4	–1.0
United States	6.7	0.6	3.3	–2.7	2.0	–1.4
Full-sample average	5.1	–0.5	2.8	–3.3	1.9	–2.4
War-torn Group 1 average	4.0	–1.4	2.7	–4.1	1.9	–3.3
Non-war-torn Group 2 average	6.4	0.7	3.0	–2.3	1.8	–1.1

creation of new enterprises in the wake of war was an even more important engine for economic recovery than in the Group 2 nations.

Thus, in Group 2 "normal nations" (i.e., those untroubled by war, political instability, and government confiscation of wealth), the natural ongoing capitalization of new technologies apparently produces a net dilution of outstanding shares of slightly more than 2 percent a year. The Group 1 nations scarred badly by war represent a more fascinating phenomenon; they can be thought of as experiments of nature in which physical capital is devastated and must be rebuilt. Fortunately, destroying a nation's intellectual, cultural, and human capital is much harder than destroying its economy; within little more than a generation, the GDP and per capita GDP of war-torn nations catch up with, and in some cases surpass, those of the undamaged nations. Unfortunately, the effort requires a high rate of equity recapitalization, which is reflected in the substantial dilution seen in Table 1 for the war-torn countries. This recapitalization savages existing shareholders.

In short, the U.S. experience was not unique. Around the world, every one of these countries except Sweden experienced dividend growth sharply slower than GDP growth, and only two countries experienced dividend growth even slightly faster than per capita GDP growth. The U.S. experience was better than most and was similar to that of the other nations that were not devastated by war.

The data for the individual countries in Table 1 show that the average real growth in dividends was negative for most countries. It also shows that dilution of GDP growth (the fourth column) was substantial for all the countries studied and that dilution of per capita GDP growth (the last column) was substantial for most countries but fit dividend growth with much less "noise" than did the dilution of overall GDP growth.

This analysis has disturbing implications for "paradigmistas" convinced of the revolutionary nature of biotechnology, Internet, and telecommunications/broadband companies. A rapid rate of technological change may, in effect, turn "normal" Group 2 nations into strife-torn Group 1 nations: An increased rate of obsolescence effectively destroys the economic value of plant and equipment as surely as bombs and bullets, with the resultant dilution of per share payouts happening much faster than the technology-driven acceleration of economic growth—if such acceleration exists. How many of the paradigmistas truly believe that the tech revolution will benefit the shareholders of existing enterprises remotely as much as it can benefit the entrepreneurs creating the new enterprises that make up the vanguard of this revolution?

Whatever the true nature of the interaction of technological progress and per share earnings, dividends, and prices, it will come as an unpleasant surprise to many that even in the Group 2 nations, average real per share dividend growth was only 0.66 percent a year (rounded in Table 1 to 0.7 percent); for the war-torn Group 1 nations, it was disturbingly negative.

In short, the equity investor in a nation blessed by prolonged peace cannot expect a real return greatly in excess of the much-maligned dividend yield; the investor cannot expect to be rescued by more rapid economic growth. Not only is outsized economic growth unlikely to occur, but even if it does, its benefits will be more than offset by the dilution of the existing investor's ownership interest by technology-driven increased capital needs.

Big Lie #2: Stock Buybacks

Stock buybacks are attractive to companies and beneficial to investors. They are a tax-advantaged means of providing a return on shareholder capital and preferable to dividends, which are taxed twice. Buybacks have enormous appeal. But contrary to popular belief, they did not occur in any meaningful way in the 1990s.

To support this contention, we begin with a remarkably simple measure of slippage in per share earnings and dividend growth: the ratio of the proportionate increase in market capitalization to the proportionate increase in stock price. For example, if over a given period, the market cap increases by a factor of 10 and the cap-weighted price index increases by a factor of 5, a 100 percent net share issuance has taken place in the interim. Formally,

$$\text{Net dilution} = \left(\frac{1+c}{1+r}\right) - 1,$$

where c is capitalization increase and r is price return. This relationship has the advantage of factoring out valuation changes, which are embedded in both the numerator and denominator, and neutralizing the impact of stock splits. Furthermore, it holds only for universal market indexes, such as the CRSP 1–10 or the Wilshire 5000, because less inclusive indexes can vary the ratio simply by adding or dropping securities. **Figure 4** contains plots of the total market cap and price indexes of the CRSP 1–10 beginning at the end of 1925.

The CRSP data contained NYSE-listed stocks until 1962. Even the CRSP data, however, can involve adding securities: CRSP added the Amex stocks in July 1962 and the Nasdaq stocks in July 1972, which created artificial discontinuities on those dates. The adjustment for these shifts is evident in **Figure 5**, for which we held the dilution ratio constant during the two months in question.[3] Note how market cap slowly and gradually pulls away from market price. The gap does not look large in Figure 4, but by the end of 2001, the cap index had grown 5.49 times larger than the price index, suggesting that for every share of stock extant in 1926, 5.49 shares existed in late 2001. The implication is that net new share issuance occurred at an annualized rate of 2.3 percent a year. Note that this rate is identical to the average dilution for non-war-torn countries during the 20th century given in Table 1. To give a better idea of how this dilution has proceeded over the past 75 years, Figure 5 provides a dilution index, defined as the ratio of capitalization growth to price index growth.

Figure 4. CRSP 1–10 Market Cap and Price Indexes, 31 December 1925–June 2002

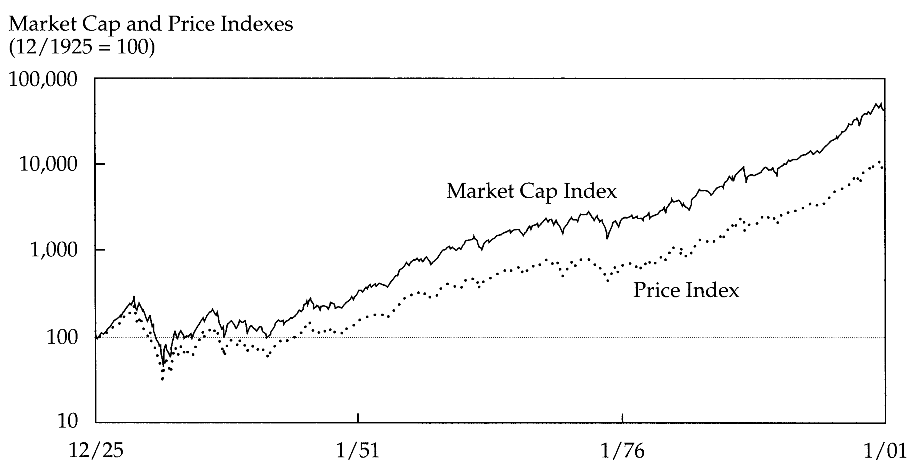


Figure 5. Cumulative Excess Growth of Market Cap Relative to Price Index, 31 December 1925 through June 2002

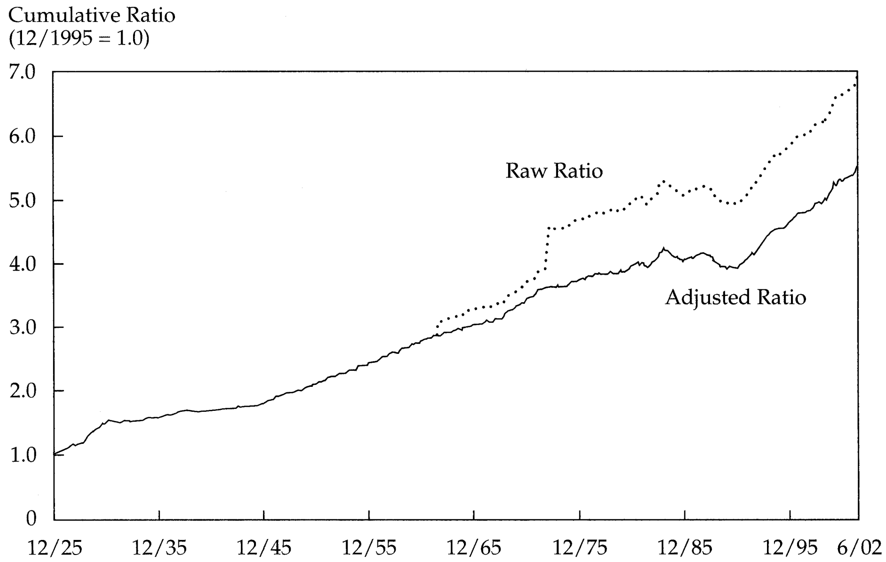
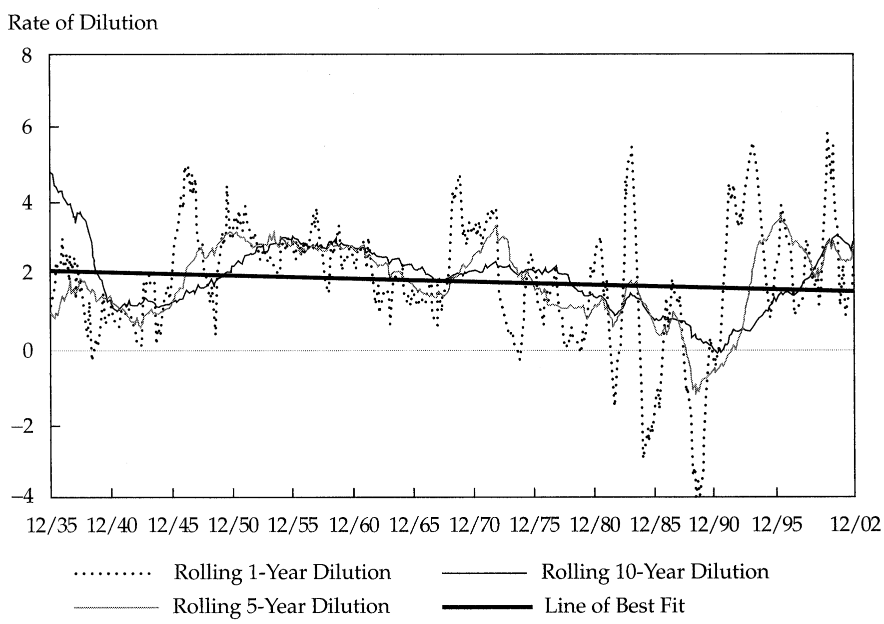


Figure 5 traces the growth in the ratio of the capitalization of the CRSP 1–10 Index as compared with the market-value-weighted price appreciation of these same stocks. The fact that this line rises nearly monotonically shows clearly that new-share issuance almost always sharply exceeds stock buybacks. The notable exception occurred in the late 1980s, when buybacks modestly outpaced new share issuance (evident from the fact that the line falls slightly during these "Milken years"). This development probably played a key role in precipitating the popular illusion that buybacks were replacing dividends. For a time, they did. But that stock buybacks were an important force in the 1990s is simply a myth. And belief in the myth may have been an important force in the bull market of the 1990s.

Figure 6 shows the rolling 1-year, 5-year, and 10-year dilution effect on existing equity shareholders as a consequence of a growth in the aggregate

Figure 6. Annualized Rate of Shareholder Dilution, 31 December 1935 through June 2002



supply of equity shares. Keep in mind that every 1 percent rise in equity capital is a 1 percent rise in market cap in which existing shareholders did not (could not) participate. Aside from the 1980s, this dilution effect on shareholders was essentially never negative—not even on a one-year basis. One can see how the myth of stock buybacks gained traction after the 1980s; even the 10-year average rate of dilution briefly dipped negative in the late 1980s. But then, during the late 1990s, stock buybacks were outstripped by new share issuance at a pace that was only exceeded in the IPO binge of 1926–1930. These conclusions hold true whether one is looking at net new share issuance on a 1-year, 5-year, or 10-year basis.

Those who argue that stock buybacks will allow future earnings growth to exceed GDP growth can draw scant support from history. Investors did see enormous earnings growth, far faster than real economic growth, from 1990 to 2000. But Figure 3 shows how tiny that surge of growth was in the context of 130 years of earnings history. Much of the earnings surge of the 1990s was dubious, at best.

The Eye of the Storm?

The big question today is whether the markets are likely to rebound into a new bull market or have merely been in the eye of the storm. We think the markets are in the eye.

The rapid earnings growth of the 1990s, which many pointed to as "proof" of a new paradigm, had several interesting characteristics:

1. A trough in earnings in the 1990 recession transformed into a peak in earnings in the 2000 bubble. Measuring growth from trough to peak is an obvious error; extrapolating that growth is even worse. This decade covered a large chunk of the careers of most people on Wall Street, many of whom have come to believe that earnings can grow very fast for a very long time. Part of conventional wisdom now is that earnings growth can outstrip macroeconomic growth.
2. Influenced by the new paradigm, analysts frequently ignored write-offs to focus increasingly on operating earnings. This practice is acceptable if write-offs are truly "extraordinary items," but it is not acceptable if write-offs become a recurring annual or biannual event, as was commonplace in the 1990s. Furthermore, what are extraordinary items for a single company are entirely ordinary for the economy as a whole. In some companies and some sectors, write-offs are commonplace. The focus on operating earnings for the broad market averages is misguided at best and deceptive at worst.
3. Those peak earnings of 1999–2000 consisted of three dubious components. The first is an underrecognition of the impact of stock options, which various Wall Street strategists estimated at 10–15 percent of earnings. The second is pension expense (or pension "earnings") based on assumptions of a 9.5 percent return, which were realistic then but are no longer; this factor pumped up earnings by approximately 15 percent at the peak and 20–30 percent from current depressed levels. The third component is Enron-style "earnings management," which various observers have estimated to be 5–10 percent of the peak earnings. (We suspect this percentage will turn out to be conservative.)

If these three sources of earnings overstatement (aggressive pension accounting, failure to expense management stock options, and outright fraud) are removed, the $54 peak earnings per share for the S&P 500 Index in 2000 turn out to be closer to $36. This figure implies normalized earnings a notch lower still. If the normalized earnings for the S&P 500 are in the $30–$36 range, as we suspect is the case, then the market at mid-year 2003 was still at a relatively rich 27–32 times normalized earnings. Using Shiller's (2000) valuation model (real S&P 500 level divided by 10-year average of real reported earnings) confirms this analysis. Shiller's model pegs the current multiple at nearly 30 times normalized earnings in mid-2003.

In principle, several conditions could allow earnings growth to exceed GDP growth. Massive stock buybacks are one. But we have demonstrated that buybacks in the 20th century were far more smoke than fire. Buybacks have been much touted as the basis for sustained earnings growth at unprecedented rates, but they simply do not show up in the data on market capitalization relative to market index price levels. Cross-holdings could also offer an interesting complication. But again, their impact does not show up in the objective shareholder dilution data. We have demonstrated that buybacks and cross-holdings do not yet show any signs of offsetting the historical 2 percent dilution, but the exploration of the possible impact of buybacks and cross-holdings is beyond the scope of this study.

Conclusion

Expected stock returns would be agreeable if dividend growth, and thus price growth, proceeded at the same rate as, or a higher rate than, aggregate economic growth. Unfortunately, dividends do not grow at such a rate: When we compared the Dimson et al. 20th century dividend growth series with aggregate GDP growth, we found that even in nations that were not savaged by the century's tragedies, dividends grew 2.3 percent more slowly, on average, than GDP. Similarly, by measuring the gap between the growth of market cap and share prices in the CRSP database, we found that between 1926 and the present, a 2.3 percent net annual dilution has occurred in the outstanding number of shares in the United States.

Two independent analytical methods point to the same conclusion: In stable nations, a roughly 2 percent net annual creation of new shares—the Two Percent Dilution—leads to a separation between long-term economic growth and long-term growth in dividends per share, earnings per share, and share price.

The markets are probably in the eye of a storm and can expect further turmoil as the rest of the storm passes over. If normalized S&P 500 earnings are $30–$36 per share, if payout ratios on those normalized earnings are at the low end of the historical range (implying lower-than-normal future earnings growth), if normal earnings growth is really only about 1 percent a year above inflation, if stock buybacks have been little more than an appealing fairy tale, if the credibility of earnings is at an all-time low, and if demographics suggest Baby Boomer dis-saving in the next 20 years, then we have a problem.

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Notes

1. In calculating "trend growth," we used a loglinear line of best fit to minimize the impact of distortions from an unusually high or low starting or ending date. The loss years of 1932 and 1933 were excluded because of loglinear calculation.
2. The Dimson et al. book is a masterwork. If you do not have a copy, you should.
3. We assumed the dilution factor to be zero in those two months. If a massive stock buyback or a massive new IPO occurred during one of these two months, we may have missed it. But net buybacks or net new share issuance during months in which the "index" saw a major reconstitution would be difficult to measure.

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Measuring the equity risk premium

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Peter Best*
is a senior portfolio manager at Old Mutual Asset Managers in London, where he manages international equities using quantitative models.

Alistair Byrne
is Head of Investment Strategy at AEGON Asset Management in Edinburgh and is also responsible for the firm's quantitative research team. Peter and Alistair have been working on risk premium analysis since 1995, when they were both at Scottish Equitable.

*Old Mutual Asset Managers Limited, 80 Cheapside, London EC2V 6EE, UK.
Tel: +44 20 7332 7558; e-mail: peter.best@omam.co.uk

Abstract We use surveys of economic forecasts to derive a forward-looking estimate of the US equity risk premium (ERP) relative to government bonds. Our ERP measure helps predict short-term relative returns between stocks and bonds. Over the period we studied, low readings of the ERP tended to adjust back to the mean via a rally in the bond market rather than a fall in stock prices. We do not generalise from this result, however, as our sample period is characterised by strong trends of falling inflation and rising stock prices. Our estimate of the expected ERP — averaging just over 2 per cent — is markedly lower than the premium that historical studies show has been realised. Data from the UK paint a similar picture to the US experience.

Keywords: *equity risk premium; survey data; asset allocation*

Introduction

In this paper, we use surveys of consensus economic forecasts to produce a forward-looking estimate of the equity risk premium (ERP) relative to government bonds for the US market. Using this novel data source, our model provides a more realistic estimate of the *ex ante* ERP than assuming that realised returns accurately indicate what investors expected. Furthermore, the ERP offers the potential to be used as the basis of a tactical asset allocation strategy by active investment managers.

We find that our ERP measure shows a tendency to mean revert and helps predict relative returns between US stocks and bonds; high values of the risk premium are associated with above-average short-term equity–bond return spreads. Also, when the ERP is low, the correction typically takes place via a rally in the bond market rather than a fall in stock prices. We need to be cautious in generalising this result, however, as the period we investigate is characterised by strong trends of falling inflation and rising stock prices.

In the sections that follow, we outline our measure of the ERP and describe the underlying data. We then test the power of the measure in predicting relative returns between stocks and bonds and look in detail at what contributes to this. In particular, we look at the process by which extreme values of the series adjust back towards the mean. We also look briefly at UK data to assess the similarity with the US experience.

Table 1 US stock and bond returns, 1900–1999 (%)

	Stocks	Government bonds
Arithmetic average annual return	12.2	5.0
Standard deviation	20.0	8.1

Source: Dimson *et al*. (2000).

The equity risk premium

Finance theory holds that stocks are more 'risky' than government bonds — meaning that equity prices are more volatile than bond prices. Investors require higher expected returns in order to invest in the (volatile) stock market than they do to invest in (more stable) bonds. In simple terms, equity returns must offer a 'risk premium' compared with the returns available on bonds and treasury bills. Welch (1999) notes that this equity risk premium 'is perhaps the single most important number in financial economics', with implications for asset allocation decisions and providing a key input into calculations of the appropriate discount rate for evaluating investments.

It is well documented that US stocks have delivered higher returns, on average, than US Treasury bonds. Returns on the stock market have also been more volatile than those earned from bonds. Figures for the period 1900–1999 are shown in Table 1.

Welch describes the approach of extrapolating the historically realised equity premium as 'the most popular' method of obtaining an estimate of the required ERP. His survey of the views of 226 financial economists yields an average estimate for the ERP relative to treasury bills of about 7 per cent, not far below the figure derived from historical information. Mehra and Prescott (1985) noted that the realised ERP in the US from 1889 to 1978 (6 per cent) was much larger than could be explained by standard models of risk aversion. Implicitly, they make the assumption that the realised figure they measured is a fair estimate of what investors had required. Their paper sparked a search for a solution to the 'equity premium puzzle'.[1]

The view that the realised ERP is a fair estimate of what investors *required*, or expected, however, needs some quite strong assumptions. We must assume the investors hold 'rational expectations' and that the required risk premium is constant. The growing literature on behavioural finance contains many illustrations of investors making decisions that are inconsistent with the traditional notions of rationality used in finance.[2] Furthermore, Fama and French (1989) present plausible arguments and evidence to suggest risk premiums are not constant, but rather vary through the business cycle. It is also possible to argue that structural factors, such as changing demographics, can cause longer-term shifts in the level of required risk premiums.

Relaxing the rational expectations and constant risk premium assumptions breaks the link between what actually happened — the realised risk premium — and the premium expected by investors when they made their investment. Bernstein (1997), in particular, argues that realised returns on stocks and bonds — and risk premium estimates derived from them — are dominated by unexpected changes in valuations. Siegel (1999) notes the high realised ERP appears to be due more to low returns on bonds than to high returns on stocks. The average real

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return on fixed income assets this century looks unduly low, and he suggests this may be the result of investors' failure to anticipate higher inflation.[3] If the high realised ERP was not expected by investors, there may not be an 'equity premium puzzle', at least not in the sense used by Mehra and Prescott.

Overall, we think the evidence weighs against the realised ERP being a good measure of the premium investors actually expected. A key motivation of our work is to find a better way of estimating the risk premium expected by investors than the 'extrapolation' approach. As active investors, we also want to assess whether the estimate is a useful predictor of short-term relative returns. The following section outlines the model we use.

Our model

The *ex ante* ERP is simply the difference in expected return between stocks and bonds.

In notation form:

$$ERP = r - y \tag{1}$$

where ERP is the *ex ante* equity risk premium, r is the expected return on the stock market, and y is the expected return on long-term government bonds.

The expected return on the stock market can in turn be expressed in terms of the constant growth dividend discount model developed by Gordon (1962).[4] The model is represented as follows:

$$r = (d/p) + g \tag{2}$$

where d is the expected value of dividends payable in the coming year, p is the price of the stock market index, and g is the expected long-term growth rate of dividends.

Substituting Equation (2) into Equation (1) yields the following expression for the ERP:

$$ERP = (d/p) + g - y \tag{3}$$

The obvious problem with Equation (3) is that only one of the right-hand-side variables, p, the value of the stock market index, is observable. The other variables relate to investors' expectations and are not directly observable. To make our model operational, we need to find proxies for these expectations.

Variable y, the expected return on government bonds, can be dealt with relatively easily. The current redemption yield on a government bond is a reasonable approximation of its longer-term expected return, and this can be observed in the market.[5]

Survey data can be used to provide estimates of d and g. Analysts' forecasts for corporate earnings are readily available through services such as IBES.[6] Each month IBES collate analysts' earnings estimates for each stock and calculate a 'consensus' in the form of the mean forecast. It is then possible to aggregate these forecasts to derive an earnings figure for the market as a whole. By applying a payout ratio to the forecasts of the following year's earnings, we can arrive at an estimate of d, the next period dividends expected by investors. The calculation of the payout ratio is discussed in the next section.

We also need an estimate of expectations of the long-term rate of dividend growth. Over the longer term, we assume that profits, and by implication dividends, will grow at the same pace as nominal gross domestic product. For this assumption to be true, a number of conditions must hold, namely that the stock market index is representative of the economy as a whole, the profit share of GDP is steady, the overseas earnings of US listed companies grow at the same pace as their domestic profits, and the payout ratio is steady. While these conditions may not hold exactly, our analysis will show whether our approach represents a valid proxy for long-term dividend growth expectations.

Long-term 'consensus' forecasts of GDP growth are available from a publication called *Blue Chip Economic Indicators* (various editions). Each month since August 1976, Blue Chip has published a survey of economists' forecasts of key variables for the US economy looking one to two years ahead. The survey takes forecasts from about 50 economists at major financial institutions, industrial corporations and consulting firms. Twice a year since 1979, the survey has been extended to cover the economists' ten-year forecasts. We use the Blue Chip ten-year forecast of nominal GDP growth as our proxy for g — the expected long-term rate of dividend growth.

We are now in a position to estimate the ERP from Equation (3) using observable proxies for the unobservable expectation variables. In the next section, we examine whether our estimate of the ERP is useful as a measure of valuation — specifically, whether it helps predict the short-term return spread between stocks and bonds.

Our measure is closely related to the practice common among market participants of estimating the ERP by comparing the nominal yields available on stocks and bonds — either in ratio form or as a difference. In difference form, this comparison is equivalent to our model with the long-term growth parameter, g, missing. The risk in excluding this parameter is that we may confuse yield shifts that are an appropriate response to changing profit growth expectations with shifts driven by other factors, possibly including 'irrational' misvaluation. In the following section, we test these alternative specifications of the risk premium model. We also test specifications of our model using actual rather than forecast dividends.

Predicting relative returns

In this section, we test whether our estimate of the ERP is useful for predicting the short-term return spread between stocks and bonds. If investors require a risk premium for investing in (volatile) stocks rather than (more stable) bonds, this implies stocks should outperform bonds on average over the long run. However, the degree of outperformance we observe is volatile and, in some shorter periods, bonds return more than stocks. Our ERP measure may offer a more reliable prediction of the return spread in any single period than simply assuming the historical average will hold.

We make the assumption that the equilibrium level of the ERP is relatively stable over time.[7] Our hypothesis is then that unusually high observations of the ERP should be associated with subsequent periods when stocks outperform bonds by more than average and the risk premium reverts towards its mean level. In contrast, unusually low observations should be associated with low, and possibly negative, return spreads between stocks and bonds as the risk premium reverts to the mean.

It is possible for our risk premium series to mean revert without being a useful predictor of relative returns between stocks and bonds. It may be that the expectation variables in our model change in such a way as to generate mean reversion in the risk premium series independent of moves in relative prices. Our tests deal with this

Table 2 Equity risk premium and relative returns, March 1979–March 1999 (%)

	ERP	Subsequent stock return	Subsequent bond return	Stock–bond return spread
Mean	2.06	8.60	4.37	4.23
Standard deviation	1.33	11.68	7.08	12.81
Minimum	0.11	−18.02	−11.03	−33.54
Maximum	6.25	38.85	23.52	39.03

All returns are expressed as semi-annual rates.

by looking directly at whether the ERP predicts relative returns.

The data we require to estimate Equation (3) are obtained from a number of sources. The forecasts of long-run nominal GDP we use to proxy dividend growth are available from the Blue Chip publication in March and October each year from 1979, with the survey being published on the 10th of the month.[8] We match these data with the corresponding level of the S&P500 index and the ten-year Treasury note yield obtained from Datastream. In the latter case, we use the Datastream Ten Year Benchmark index.

IBES data are used to estimate the forward dividend yield on the S&P500 index. We apply an estimated payout ratio of 0.4 to the IBES consensus forecast of the next 12 months' earnings. We estimate the payout ratio by calculating the relationship between IBES earnings forecasts and subsequent dividends over the period for which we have data. On average, subsequent dividends amount to about 40 per cent of the earnings forecast. Varying the payout ratio between 30 per cent and 50 per cent shows the results of our analysis are largely insensitive to the figure used.

We also use Datastream to source total return data for the S&P500 index and the ten-year benchmark bond index. We match each calculation of the risk premium with the total returns on stocks and bonds in the following period, eg we calculate the risk premium on 10th March and match this with returns from 10th March to 10th October. Since the Blue Chip data are published in March and October, our time series consists of five-month and seven-month periods rather than actual half years. We transform the five-month and seven-month returns into the corresponding semi-annual rates. The return spread series is calculated in ratio form rather than as differences.

Descriptive statistics for the estimated ERP and the relative return series are shown in Table 2. The ERP measure is graphed in Figure 1. While the sample period is short by comparison with those used in many academic studies, it has to be noted that we are constrained by the availability of the survey data. We have used all of the available data.[9]

Figure 1 shows the ERP started the sample period at a high level of over 5 per cent, perhaps reflecting the uncertain economic environment following the second OPEC oil price 'shock'. The premium declined sharply over the following two years and the range 1–3 per cent is much more typical for the rest of the sample period, with the mean level just over 2 per cent. Most deviations outside this range look to have 'corrected' quite quickly. Interestingly, the range is consistent with the theoretical estimates produced by Mehra and Prescott (1985) using standard models of risk aversion. The low of the series occurs in October 1987, just before the 'crash'. It is notable that the

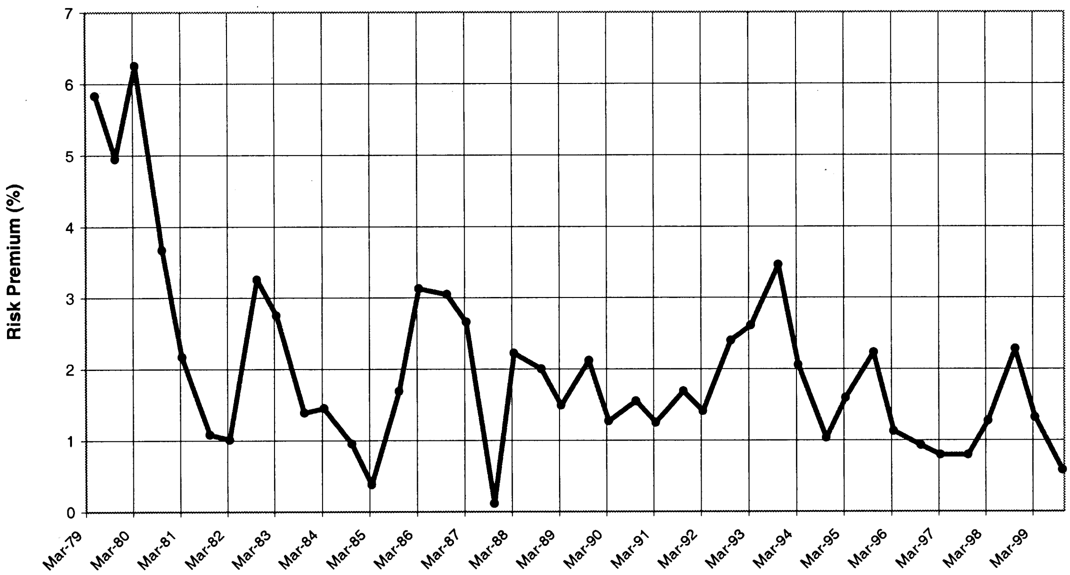

Figure 1 US equity risk premium

last data point from October 1999 is the third-lowest reading in the series, lending support to some commentators' concerns about high valuation levels in the US equity market.

To test whether our ERP measure is a useful predictor of the return spread between stocks and bonds, we estimate an ordinary least squares regression, where the level of the ERP at the end of one period is used to explain the return spread in the following period.

In notation terms:

$$SVB_t = a + b\ ERP_{t-1} + e_t \qquad (4)$$

where SVB_t is the log total return on stocks in period t relative to the total return on bonds [=(1 + total return on S&P500 index)/(1 + total return on Datastream 10-Year Treasury Index)], ERP_{t-1} is the estimated ERP at the end of period $t-1$, and e_t is the error term. The results of the regression are shown in Table 3.

The regression equation reveals a positive relationship between our ERP measure and the subsequent return spread between stocks and bonds. The t-statistic of 3.3 indicates the relationship is statistically significant at a 99 per cent confidence level. Our ERP measure explains almost 20 per cent of the variation in relative returns between stocks and bonds over the sample period. Diagnostic tests show no significant econometric problems, although the sample size is relatively small.

Putting our results into more obvious economic terms, on average, stocks outperformed bonds by 4.2 per cent in each semi-annual period in our sample. The average ERP measure over the sample period was 2.1 per cent. For every percentage point increase (decrease) in the ERP, the subsequent semi-annual relative return was increased (decreased) by 4.5 percentage points. Figure 2 shows a scatter diagram of the ERP

Table 3 Regression results, March 1979–March 1999

	$SVB_t = -5.00 + 4.47\ \mathrm{ERP}_{t-1}$	
t-statistics	(−1.50) (3.27)	
Adjusted	$R^2 = 19.5\%$	$n = 41$

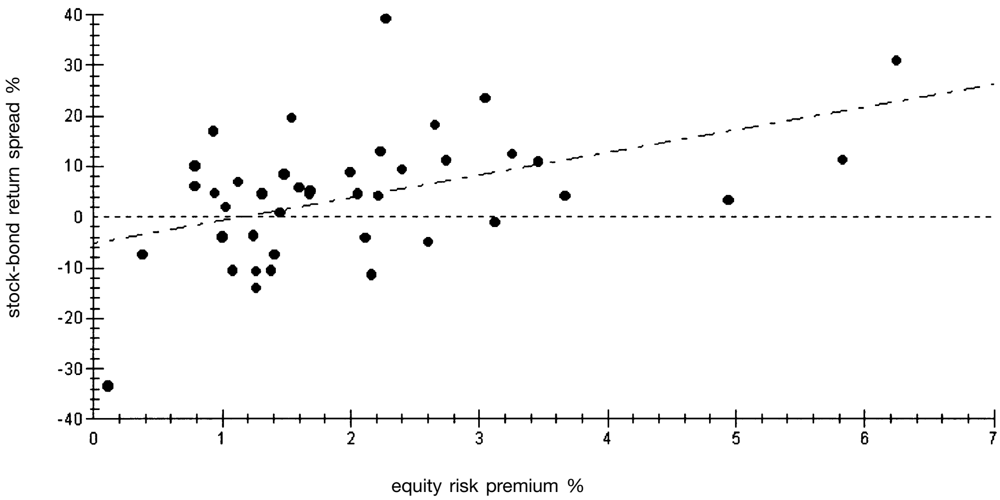

Figure 2 Stocks and bonds return spread against equity risk premium

observations against the subsequent equity–bond return spread. The positive relationship can be seen in the data.

In order to test the robustness of our results, we also tested a number of alternative specifications of the ERP. Using actual dividends rather than the IBES forecasts produces results that are similar, but slightly weaker, than our initial specification. Using the difference between the nominal earnings yield on stocks and the bond yield, ie omitting the long-term growth term, also produces similar results for predicting relative returns. This measure does not show significant mean reversion, however, raising questions about its reliability. Using the ratio between the forecast earnings yield on the stock market and the bond yield produces results similar to but slightly stronger than our chosen specification. Our main concern about this specification is that it is unlikely to be robust to significant changes in long-term dividend growth expectations. Using the Blue Chip forecasts for growth in the national income definition of profits rather than nominal GDP produces similar, but slightly weaker results.

In short, the alternative specifications produce similar, though generally slightly weaker, results. We would argue that the more complete specification of our measure makes it more robust to changes in the environment, especially revised long-term growth expectations.

What really happened

We have established that our risk premium measure is a reliable predictor of the return spread between stocks and bonds. An unusually high risk premium implies stocks will outperform bonds by a wider-than-average margin in the following period. Similarly, a low-risk premium implies the short-term return margin between stocks and bonds will be narrow or even negative.

To investigate what is driving these results, we rank the 41 observations according to the level of the ERP. We then split the data into quartiles — missing out the median observation[10] — and examine the return characteristics of each quartile. The results are shown in Table 4. Note all returns shown are expressed on a semi-annual basis.

Table 4 reveals that in quartiles one

Table 4 Equity risk premium and returns by quartile (%)

	Average ERP	Average relative return	Average stock return	Average bond return
Quartile One	3.90	12.38	11.29	−1.09
Quartile Two	2.18	6.29	8.17	1.88
Quartile Three	1.40	−0.81	4.75	5.56
Quartile Four	0.82	−0.97	8.24	9.21

All returns are expressed as semi-annual rates.

and two, bond returns are below average, while stock returns are higher than average. It is apparent that the above-average relative returns observed in these quartiles are driven both by below-average bond returns and by above-average stock returns. In quartiles three and four, bonds perform better than stocks on average, which is unsurprising given the econometric results in the previous section. The mechanism for this result is interesting, however. The 'overvaluation' of stocks is usually corrected by a rally in the bond market rather than by stocks falling in price — stock returns are below average, but not generally negative. The most notable exception is the October 1987 data point. The forecast ERP registered just 0.1 per cent on 10th October 1987. Over the following five months, bonds delivered a 15.5 per cent semi-annual return, helping to restore a more normal ERP. Stocks dropped sharply, however, registering a return of −18.0 per cent for the period. As we know, the 22.0 per cent 'crash' on Black Monday, 19th October, caused most of the damage to investors' portfolios.

Our measure appears to have some predictive power over both stocks and bonds individually as well as over relative returns. To confirm these results in econometric terms, Table 5 shows regression equations where we use the ERP measure to predict the return on stocks S_t and the return on bonds B_t.

As expected given the quartile analysis above, there is a negative relationship between the ERP measure and the return on bonds, ie bonds tend to perform poorly in the period following a high ERP. Stocks tend to perform strongly following a high ERP, as shown by the positive regression coefficient. The main caveat is that the regression coefficient for stocks is not statistically significant at conventional confidence levels.

Our results show that over the period for which we have data, overvaluation of the stock market relative to bonds has tended to be corrected by a rally in the bond market, ie a fall in yields. In only seven of the 41 periods was the return on the stock market negative. It would be wrong to generalise from this result, however. Over the period we studied, the average level of inflation dropped sharply, providing a beneficial environment for financial assets. Consumer price inflation averaged 7.9 per cent in the five years leading up to

Table 5 Regression results, March 1979–March 1999

Stocks			
	$S_t = 5.32 + 1.59\ \mathrm{ERP}_{t-1}$		
t-statistics	(1.57) (1.15)		
Adjusted	$R^2 = 0.8\%$	$n = 41$	
Bonds			
	$B_t = 10.33 - 2.89\ \mathrm{ERP}_{t-1}$		
t-statistics	(5.89) (−4.03)		
Adjusted	$R^2 = 27.5\%$	$n = 41$	

Table 6 UK equity risk premium and relative returns, April 1982–April 1999 (%)

	ERP	Subsequent stock return	Subsequent bond return	Stock–bond return spread
Mean	2.07	8.40	5.88	2.52
Standard deviation	1.22	12.01	6.20	11.96
Minimum	0.35	−26.75	−6.66	−38.26
Maximum	5.34	30.00	24.53	24.41

All returns are expressed as semi-annual rates.

our first data point in March 1979. For the five years to October 1999, the comparable figure is 2.4 per cent. The ten-year bond yield has fallen in tandem with the drop in inflation, moving from 9.1 per cent in March 1979 to 6.0 per cent in October 1999. Without this beneficial environment of falling inflation, and rising stock prices, investors buying stocks when the risk premium was low may have faced a harsher experience than they have had.

While many investors and media commentators have been talking about the overvaluation of the US stock market for several years, there has been significant variation in the level of the ERP measure over the recent period. During the third quarter of 1998, stocks fell sharply as investors undertook a 'flight to safety' in the aftermath of the Russian government's decision to introduce a moratorium on debt repayments. Treasury bond yields fell as investors sought secure and liquid instruments in which to hold their capital. The result was to drive the ERP to an above-average level of 2.3 per cent in October 1998. In contrast, the March 1998 reading was only 1.3 per cent. The October 1998 data point stands out as the 'best' buying signal for equities in our series, with the S&P500 index outperforming bonds by 39.0 per cent on a semi-annual basis over the following five months, as fears of deflation and recession abated.

The international evidence

We have focused on the US market due to the ready availability of the survey data we use to proxy expectations. Some data, however, are also available for international markets. In particular, we have been able to assemble a series of ERP estimates for the UK market from April 1982 to April 1999 using IBES earnings forecasts and long-run nominal GDP from Consensus Economics Inc.'s *Consensus Forecasts* (various editions), an international equivalent to *Blue Chip Economic Indicators*.[11] We use the FTSE 100 as our equity index and the Datastream ten-year benchmark gilt index for our bond series. With the exception of the sources of the forecasts, the methodology and data sources are the same as outlined for the US in the section on 'Our model'. Table 6 gives descriptive statistics for our UK ERP measure and the corresponding returns. Figure 3 plots the ERP series.

It is notable that the UK series shares many similarities with our US data. The mean level of the ERP, at 2.1 per cent, is almost identical to the US average. The highs and lows are also broadly similar, and both series typically occupy a range from about 1 per cent to 3 per cent. Unlike the US, October 1987 did not represent the low for the UK, which in fact occurred in April 1991. The last data point in the sample, 1.7 per cent in October 1999, is much closer to the mean than the comparable US observation.

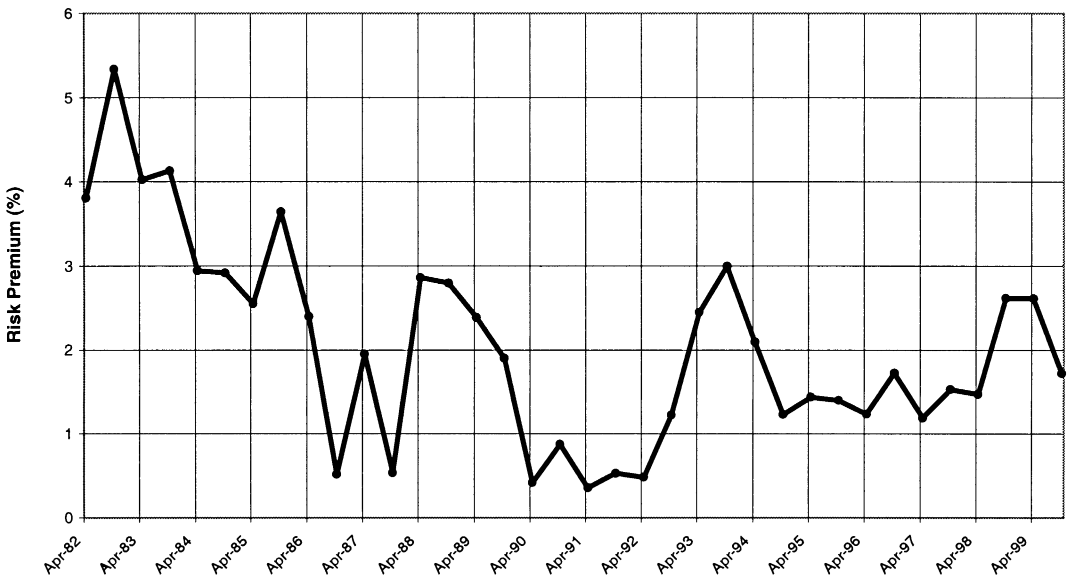

Figure 3 UK equity risk premium

Following the US analysis, we also test whether the UK ERP series helps predict the short-term stock–bond return spread. The regression yields a slope coefficient of 3.72 with a *t*-statistic of 2.35 — similar to the US equation. The adjusted *R*-square statistic at 12 per cent is lower than in the US model. Overall, the results are qualitatively similar.

Regression of the ERP series on stock and bond returns separately produces a contrast to the US results. In our results (not shown), we find the ERP series is more predictive of stock returns than bond returns. The slope coefficient of the bond equation is statistically insignificant, though it has the expected negative sign.

In general, the UK results and their similarity to the US experience give us confidence in the validity of our approach. The techniques are also applicable for other international markets, but data availability is a problem. For many European and Asian markets, comprehensive surveys of economic forecasts have only become available in the past decade. This will, however, provide a useful 'out-of-sample' test of our analysis once the data histories are longer.

Table 7 Regression results, April 1982–April 1999

Stocks
$SVB_t = -5.19 + 3.72\ \mathrm{ERP}_{t-1}$
t-statistics (−1.37) (2.35)
Adjusted $R^2 = 11.7\%$ $n = 35$

Conclusions

Our work represents an attempt to produce a well-specified *ex ante* measure of the ERP expected by investors. We use surveys of economic forecasts as a novel way to solve the problem that many of the variables in the risk premium calculation are unobservable. We focus on the US experience, but also present results for the UK which are similar.

The results show that the ERP measure helps predict the short-term relative return between stocks and bonds. When the premium is higher than average, the stock–bond return spread in the coming period also tends to be above average. When the risk premium measure is below average, the subsequent return spread tends to be low or even negative. The measure therefore offers scope to be the basis of a tactical asset allocation strategy.[12]

It is not clear why our measure, which uses widely available data, should offer potential for generating excess returns. It may be the model captures inefficiency in the relative pricing of stocks and bonds, but other, more 'rational', explanations are possible. Fama and French (1989) find that US stock and bond returns between 1926 and 1987 were predictable using the market dividend yield; the 'default' spread between the average corporate bond yield and the yield on AAA-rated bonds; and the term premium of AAA-rated corporate bonds over Treasury bills. They argue the explanatory variables are related to the business cycle and that predictable variation in expected returns reflects a rational response to economic conditions. For example, when business conditions are poor, income is low and expected returns from bonds and stocks must be high to induce substitution from consumption to investment. In the case of our analysis, it may be that the business cycle leads to short-term fluctuations in the compensation investors require for equity risk. Similarly, the actual or perceived level of risk in stocks and bonds may vary through the business cycle, leading to variations in expected returns that have rational foundations. Our tests do not offer any way to decide between these different explanations.

Our analysis also suggests, in recent years at least, the risk premium expected by equity investors has been significantly less than the levels (7 per cent or so) that historical studies show have been realised. The most recent US data we have show stocks priced to deliver only about 1 per cent more than bonds over the longer term, if our model specification is correct. Our concluding message has to be to caution against using a measure of the realised ERP as an indication of what can be expected in future.

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Notes

1 A review of some of the initial solutions proposed can be found in Kocherlakota (1996).
2 See Shefrin (1999) for a comprehensive review of this field.
3 Best *et al*. (1998) show that investors in the US bond market in recent years appear to have made large and persistent errors in forecasting inflation. As a result the realised real returns earned by these investors seem to have been very different from what they expected at the outset. It is not apparent in the data that these forecast errors average out to zero over time.
4 The Gordon model is a simple valuation model, which necessarily rests on a number of strong assumptions. The firm is assumed to be debt free and to finance its investments through retaining a constant portion of its earnings. The investments have infinite lives and earn a constant return on capital. A full critique of the model and the assumptions is outwith the scope of our paper.
5 This approximation involves a number of assumptions, such as a flat and unchanging yield curve and the ability to reinvest coupon payments at the same rate as the yield. The effect of these assumptions is likely to be small.
6 IBES is a data vendor specialising in the systematic collection of earnings estimates from 'sell-side' investment analysts.
7 It is possible to argue the risk premium will shift over time, eg as a result of changing demographics. Such changes by their nature, however, are likely to be very gradual. Tests on the ERP series indicate it is stationary over the sample period. The augmented Dickey–Fuller statistic for the series is −5.99, which is significant at a 95% confidence level.
8 Prior to 1983, some of the data points relate to May and November. After 1983, the series becomes more regular.
9 To avoid the need for survey data, some analysts assume investors have had perfect (or at least unbiased) foresight. They argue that what happened, for example in terms of dividend growth, was what

investors had expected and thus historical out-turn data can proxy for prior expectations. While this can yield longer data histories, to us the assumption is too strong.

10 The median observation is from October 1985 and is characterised by: $ERP = 1.69$ per cent; stock return = 28.01 per cent; bond return = 23.52 per cent; relative return = 4.49 per cent.

11 UK data from IBES and Consensus Economics is only available from 1987 and 1989 respectively. We create our own comparable series for the early periods by combining the relevant forecasts of leading economic forecasting institutions.

12 Best and Byrne (1997) present the results of a simulated tactical asset allocation strategy based on this measure.

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Richard A. Michelfelder *is Clinical Associate Professor of Finance at Rutgers University, School of Business, Camden, New Jersey. He earlier held a number of entrepreneurial and executive positions in the public utility industry, some of them involving the application of renewable and energy efficiency resources in utility planning and regulation. He was CEO and chairperson of the board of Quantum Consulting, Inc., a national energy efficiency and utility consulting firm, and Quantum Energy Services and Technologies, LLC, an energy services company that he co-founded. He also helped to co-found and build Comverge, Inc., currently one of the largest demand-response firms in the world, which went public in 2006 on the NASDAQ exchange. He was also an executive at Atlantic Energy, Inc. and Chief Economist at Associated Utilities Services, where he testified on the cost of capital for public utilities in a number of state jurisdictions and before the Federal Energy Regulatory Commission. He holds a Ph.D. in Economics from Fordham University.*

Panayiotis Theodossiou *is Professor and Dean of Faculty of Management at the Cyprus University of Technology. Previously he was Professor of Finance at Rutgers University, School of Business, Camden. Dr. Thedossiou has also held a number of other faculty positions in finance at Catholic University and Clarkson University. He has also provided consulting advice to national governments. He holds a Ph.D. in Finance from the City University of New York.*

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Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings

The Capital Asset Pricing Model (CAPM) is commonly used in public utility rate proceedings to estimate the cost of capital and allowed rate of return. The beta in the CAPM associates risk with estimated return. However, an empirical analysis suggests that the commonly used Blume CAPM beta adjustment is not appropriate for electric and electric and gas public utility betas, and may bias the cost of common equity capital in public utility rate proceedings.

Richard A. Michelfelder and Panayiotis Theodossiou

I. Introduction

Regulators, public utilities, and other financial practitioners of utility rate setting in the United States and other countries often use the Capital Asset Pricing Model (CAPM) to estimate the rate of return on common equity (cost of common equity).[1] Typically, the ordinary least squares method (OLS) is the preferred estimation method for the CAPM betas of public utilities. Although the CAPM model has been widely criticized regarding its validity and predictability in the literature, as summarized by Professors Fama and French in 2005,[2] many firms and practitioners extensively use it to obtain cost of common equity estimates; e.g., such as shown by Bruser et al. in 1998, Graham and Harvey in 2001, and Gray, et al. in 2005.[3] Michelfelder, et al. in 2013[4] in this

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journal presents a new model, i.e., the Predictive Risk Premium Model, to estimate the cost of common equity capital and compare and contrast the poor results of the CAPM to that model and the discounted cash flow model.

Major vendors of betas include, but are not limited to, Merrill Lynch, Value Line Investment Services (Value Line), and Bloomberg. These companies use Blume's 1971 and 1975[5] beta adjustment equation to adjust OLS betas to be used in the estimation of the cost of common equity for public utilities and other companies.

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time; that is, betas greater or less than 1 are expected to revert to 1. There are various explanations for the phenomenon first discussed in Blume's pioneering papers. One explanation is that the tendency of betas toward one is a by-product of management's efforts to keep the level of firm's systematic risk close to that of the market. Another explanation relates to the diversification effect of projects undertaken by a firm.[6]

While this may be the case for non-regulated stocks, regulation affects the risk of public utility stocks and therefore the risk reflected in beta may not follow a time path toward one as suggested by Peltzman in 1976, Binder and Norton in 1999, Kolbe and Tye in 1990, Davidson, Rangan, and Rosenstein in 1997, and Nwaeze in 2000.[7] Being natural monopolies in their own geographic areas, public utilities have more influence on the prices of their product (gas and electricity) than other firms. The rate setting process provides public utilities with the opportunity to adjust prices of gas and electricity to recover the rising costs of fuel and other materials used in the transmission and distribution of electricity and gas. Companies operating in competitive markets do not have this ability. In this respect, the perceived systematic risk associated with the common stock of a public utility may be lower than that of a non-public utility. Therefore, forcing the beta of a utility stock toward one may not be appropriate, at least on a conceptual basis.

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time.

The explanations provided by Blume and others to justify the latter tendency are hardly applicable to public utilities. Unlike other companies, utilities can and do possess monopolistic power over the markets for their products. This power impacts the ''negotiation process'' for setting electric and gas prices. Furthermore, it provides them with the opportunity to raise prices to recover increases in operating costs without regard to competitive market pressure. Such price influence is rarely available to companies operating in competitive market environments for their products. In that respect, macroeconomic factors will have a greater impact on the earnings and stock prices of the non-utility companies resulting in larger systematic risk or betas.

The application of Blume's equation to public utility stocks generally results in larger betas, since most raw utility betas are less than 1. Therefore, applications of these betas to estimate the cost of capital and an allowed rate of return on common equity possibly biases the required rate of return or cost of common equity, leading to an over-investment of capital as predicted by Averch and Johnson in 1962,[8] which preceded the trend in prudency reviews that began to occur in the 1980s. Although reported public utility betas may have been biased upward by the vendors of beta that applied Blume's adjustment to public utility betas, ex post prudency reviews of ''used and useful'' assets defined and supported by the Duquesne 1989 US Supreme Court decision[9] resulted in an underinvestment of capital in generation and transmission assets, leading to electric brownouts and blackouts. This article examines the behavior of the betas of the population of publicly traded U.S. energy utilities. In

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addition to evaluating the stability of these betas over the period from the January 1962 to December 2007, we also test whether or not public utility betas are stationary or mean reverting toward 1 or perhaps a different level.

II. Background

Investor-owned public utility regulatory proceedings to change rates for service almost always involve contentious litigation on the fair rate of return or cost of common equity. Since the cost of common equity is not observable, it must be inferred from market valuation models of common equity. The differences in the recommended allowed rates of return resulting from necessary subjective judgments in the application of cost of common equity models can easily mean 500 basis points or more in the estimate. Therefore, both the impact on customer rates for utility service and the profits of the utilities are very sensitive to the methods used to estimate the cost of common equity and allowed rate of return. The two most commonly used models are the Dividend Discount Model (DDM) and the CAPM. We discuss the use of CAPM for estimating the cost of common equity for public utilities. Our focus is on the use of market-influential betas from the major vendors of betas: Merrill Lynch, Value Line, and Bloomberg. These vendors apply Blume's adjustment to raw betas to estimate forward-looking betas. Blume[10] performed an empirical investigation, finding that beta is non-stationary and has a tendency to converge to 1. Bey in 1983 and Gombola and Kahl in 1990[11] found that utility betas are non-stationary and concluded that each utility beta's non-stationarity must be viewed on an individual stock basis, unlike the recommendation of Blume which adjusts all betas for their tendency to approach 1. Similarly with Gombola and Kahl, we find that public utility betas have a tendency to be less than 1. They investigated the time series properties of public utility betas for their ability to be forecasted whereas we are concerned with the institutional reasons for the trends in beta, the bias instilled in cost of capital estimates assuming that utility betas converge to one and the widespread use and applicability of the Blume adjustment to public utility betas. McDonald, Michelfelder and Theodossiou in 2010[12] show that use of OLS is problematic itself for estimating betas as the nonnormal nature of stock returns result in beta estimates that are statistically inefficient and possibly biased.

Investor-owned public utility regulatory proceedings to change rates for service almost always involve contentious litigation on the fair rate of return or cost of common equity.

Blume's equation is:

$$\beta_{t+1} = 0.343 + 0.677\beta_t \qquad (1)$$

where β_{t+1} is the foreasted or projected beta for stock i based on the most recent OLS estimate of firm's beta β_t. For example if β_t is estimated using historical returns from the most recent five years, then the projected β_{t+1} may be viewed as a forecast of the beta to prevail during the next five years. As mentioned earlier, Blume's equation implies a long-run mean reversion of betas toward 1. The long-run tendency of betas implied by Blume's equation can be computed using the equation:

$$\overline{\beta} = \frac{0.343}{1 - 0.677} = 1.0619 \approx 1 \qquad (2)$$

The same result can be obtained by recursively predicting beta until it converges to a final value. This can only be appropriate for stocks with average betas, as a group, close to one. This is, however, hardly the case for public utility betas that are generally less than 1 (as discussed in detail below).

The magnitude of adjustment for Blume's beta equation is initially large and declines dramatically as the adjusted beta approaches 1 either from below (for betas lower than 1) or from above (for betas greater than 1). In this respect, the beta adjustment step (size) will be larger for betas further away from 1.

As we will see in the next section, the median beta of the public utilities studied ranges between 0.08 and 0.74 over time,

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depending upon the period used. Under the assumption that betas for public utilities are consistent with Blume's equation, the next period beta for a stock with a current beta of 0.5, will be $\beta_{t+1} = 0.343 + 0.677\ (0.5) = 0.6815$, implying a 36.3 percent (0.6815/0.5) upward adjustment. On the other hand a beta of 0.4 will be adjusted to $\beta_{t+1} = 0.343 + 0.677\ (0.4) = 0.6138$ which constitutes a 53.5 percent upward adjustment and a beta of 0.3 will be adjusted to 0.5461 or by 82.0 percent.

The beta adjustment method most widely disseminated by the major beta vendors is the Blume adjustment. Therefore, our focus is on the Blume adjustment for public utility betas and the public utility cost of common equity capital. Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings since these betas are not disseminated by influential stock analysts and presumed not to be reflected in the stock price. Section III discusses the data and empirical analysis of the Blume adjustment and its impact on the cost of common equity for public utilities.

III. Data and Empirical Analysis

The data include monthly holding period total returns for 57 publicly traded U.S. public utilities for the period from January 1962 to December 2007 obtained from the University of Chicago's Center for Research in Security Prices (CRSP) database. The sample includes all publicly traded electric and electric and gas combination public utilities with SIC codes 4911 and 4931 listed in the CRSP database. All non-U.S. public utilities traded in the U.S. and non-utility stocks were not included in the dataset. The monthly holding period total returns for each stock as calculated in the CRSP database were used for estimating betas of varying periods. The monthly market total return is the CRSP value-weighted total return.

Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings.

The computation of the betas is based on the single index model, also used in Blume:

$$R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}, \qquad (3)$$

where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i are the intercept and beta for stock i and $e_{i,t}$ is a regression error term for stock i. As previously mentioned, OLS is the typical estimation method used by many vendors of beta and is used in this investigation.

Table 1 presents the mean and median OLS beta estimates for the 57 utilities using 60, 84, 96, and 108 monthly returns respectively over five different non-lapping periods between December 1962 and December 2007. We also performed the same empirical analysis for periods of 4, 6, 10, 11, 12 and 13 years and the results were similar; the results are not shown for brevity but available upon request. We used non-overlapping periods to avoid serial correlation and unit roots. If we take, for example, 360 months of time series of returns for a stock and estimate 60-month rolling betas moving one month forward for each beta, this would result in 300 betas. Since only two of 60 observations would be unique due to overlapping periods, the error term would be highly serially correlated. A Blume-type regression of these betas would have a unit root, a coefficient of one and an intercept near 0, and therefore appear to follow a random walk. Therefore, the empirical nature of beta requires that lags in the Blume equation involve no overlapping time periods.

The mean and median betas in Table 1 not only do not rise toward 1 as the time period moves forward; the betas generally decline. Table 2 includes OLS regressions of the Blume equation for the 5-, 7-, 8-, and 9-year betas. We estimated five sets of 4- through 13-year betas inclusively for each public utility then

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Table 1: Mean and Median Betas for Varying Time Periods.

9-Year Periods	12/62–12/71	12/71–12/80	12/80–12/89	12/89–12/98	12/98–12/07
Mean	0.69	0.60	0.41	0.40	0.27
Median	0.68	0.57	0.40	0.36	0.22
8-Year Periods	**12/67–12/75**	**12/75–12/83**	**12/83–12/91**	**12/91–12/99**	**12/99–12/07**
Mean	0.76	0.39	0.45	0.27	0.33
Median	0.74	0.37	0.43	0.23	0.27
7-Year Periods	**12/72–12/79**	**12/79–12/86**	**12/86–12/93**	**12/93–12/00**	**12/00–12/07**
Mean	0.68	0.40	0.40	0.09	0.50
Median	0.65	0.39	0.38	0.06	0.47
5-Year Periods	**12/77–12/82**	**12/82–12/87**	**12/87–12/92**	**12/92–12/97**	**12/97–12/02**
Mean	0.36	0.38	0.53	0.49	0.12
Median	0.35	0.38	0.50	0.45	0.08

The following model was estimated for the sample of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the single index model: $R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}$
where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i is the intercept and capital asset pricing model beta for stock i, respectively, and $e_{i,t}$ is a regression error term for stock i. The entire data series ranges from December 1962 to December 2007. The stock returns are the monthly holding period total returns from the CRSP database. The market returns are the CRSP market value-weighted total returns.

regressed the latter beta on the previous period betas. The 5-, 7-, 8-, and 9-year equations are shown for brevity. The diagnostic statistics strongly refute the validity of the Blume equation for public utility stocks. Most of the R^2's are equal to or close to 0.00 and the largest is 0.09. Only one F-statistic (tests the significance of the equation estimation) is significant and all but two slopes are insignificant. Also shown is the long-run beta implied from each Blume model as shown in equation (2). They range from 0.08 to 0.59. Only one estimate, the first-period 9-year Blume equation, includes a positive and statistically significant slope and intercept. The implied long-term beta of that equation is 0.59, which is substantially below one and the largest value of all estimates. As a final and visual review of the trends in betas, we developed and plotted probability distribution box plots developed by Tukey in 1977[13] for the 4- through 13-year public utility betas. We have shown only the 4- and 5-year beta box plots as shown in Figures 1 and 2 for brevity (the 6- to 13-year plots are available upon request). Tukey box plots show the 25th and 75th percentiles (the box height), the 10th and 90th percentiles (the whiskers), the median (the line inside the box), and the dispersion of the outlying betas. The box plots should be viewed as looking down on the distributions of the betas. We developed 4- through 13-year beta box plots to review the trend in shorter-term versus longer-term betas. None of the 51 beta probability distributions display any tendency for betas to drift toward one. The 5-, 6- and 7-year betas have higher variances in the last period relative to all other periods. A few outlying betas are greater than 2.0. This pattern is consistent with the notion that utility holding companies are investing in risky ventures of affiliates that can retain excess returns should they be realized. Note that the mean beta in Figures 1 and 2 show the cyclical nature of short-term utility betas with a severe downturn in the late 1990s and a severe upswing in the early 2000s. Generally, the box plots show a long-term downward trend in public utility betas.

It is interesting to note that the drop in beta occurred just after

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Table 2: Public Utility Blume Equation Estimates.

9-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.463***	0.318***	0.480***	0.235***
	(0.074)	(0.062)	(0.096)	(0.080)
γ_1	0.214**	0.153	−0.186	0.800
	(0.102)	(0.099)	(0.227)	(0.179)
Long Run β	0.59	0.38	0.41	0.26
R^2	0.09	0.04	0.01	0.00
F-Statistic	4.43**	2.36	0.67	0.20
p-Value	0.04	0.13	0.42	0.65
8-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.341***	0.464***	0.184**	0.321***
	(0.083)	(0.047)	(0.088)	(0.070)
γ_1	0.058	−0.034	0.193	0.035
	(0.106)	(0.115)	(0.189)	(0.220)
Long Run β	0.36	0.45	0.23	0.33
R^2	0.01	0.00	0.02	0.00
F-Statistic	0.30	0.09	1.04	0.02
p-Value	0.58	0.76	0.31	0.88
7-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.370***	0.375***	0.074	0.491***
	(0.081)	(0.052)	(0.075)	(0.049)
γ_1	0.048	0.059	0.036	0.128
	(0.115)	(0.122)	(0.179)	(0.259)
Long Run β	0.39	0.40	0.08	0.56
R^2	0.00	0.00	0.00	0.00
F-Statistic	0.17	0.23	0.04	0.24
p-Value	0.68	0.63	0.84	0.62
5-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.329***	0.474***	0.321***	0.106*
	(0.047)	(0.086)	(0.088)	(0.061)
γ_1	0.151	0.137	0.316**	0.019
	(0.119)	(0.213)	(0.157)	(0.111)
Long Run β	0.39	0.55	0.47	0.11
R^2	0.03	0.01	0.07	0.00
F-Statistic				
p-Value	1.62	0.41	4.07	0.03
	0.21	0.52	0.05	0.87

The following Blume equation was estimated using the betas of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the following model: $\beta_{i,t+1} = \gamma_0 + \gamma_1\beta_{i,t} + \varepsilon_{i,t}$.
where $\beta_{i,t+1}$ is the OLS estimated CAPM beta for stock *i*, $\beta_{i,t}$ is the previous period beta for stock *i*, γ_0 and γ_1 are the intercept and slope of the Blume equation, and ε_t is the regression error term. The time subscripts on the betas refer to the time periods of estimation from Table 1. For example, β_5 in the 9 year panel refers to the beta estimated for each stock using the returns data from December 1998 to December 2007. The long-run $\beta = \gamma_0/(1 - \gamma_1)$; it can also be found by solving recursively for the next period beta until it converges on a final value. Newey-West autocorrelation and heteroskedasticity consistent standard errors are in parentheses.
* Significance at 0.10 level.
** Significance at 0.05 level.
*** Significance at 0.01 level.

deregulation of the wholesale electricity market in April 1996. This is inconsistent with the buffering theory of Peltzman and Binder and Norton[14] who found that regulation buffers the volatility of cash flows of public utilities from the vicissitudes of competition and business cycles and therefore reduces their systematic risk. However, this is consistent with Koble and Tye's 1990[15] theory of asymmetric regulation and the empirical findings of Michelfelder and Theodossiou in 2008,[16] who found that asymmetric regulation is associated with down-market public utility betas greater than their up-market betas. Adverse asymmetric regulation began in the 1980s and resulted in an upper boundary for public utilities' allowed rates of return equal to the cost of capital. If public utilities were granted an opportunity to earn their cost of common equity, regulators frequently would disallow specific investments *ex post* from earning the allowed rate of return if they were deemed ''not used and useful,'' even though they were deemed to be prudent when the decision was made to make these investments. The result was that utilities were not truly granted the opportunity to earn their allowed rate of return. If they happened to over-earn their allowed rate of return due to higher than anticipated demand forecasts, ''excess'' returns were taken away. This became known as regulatory risk, quantified as a risk premium in the cost of

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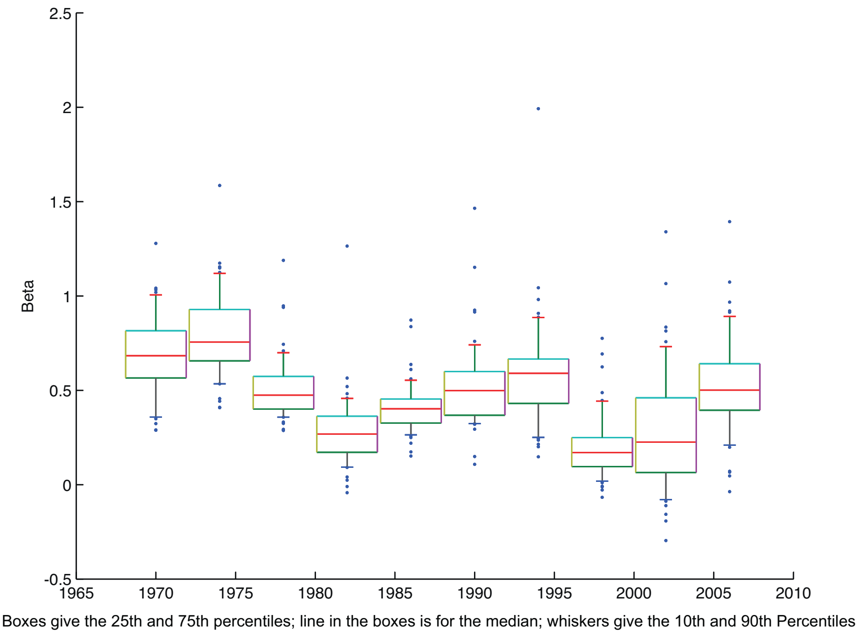

Figure 1: Boxplots of Utility Stock Betas Using 4 Year Periods Data

common equity. Michelfelder and Theodossiou in 2008[17] also concluded that public utility stocks are no longer defensive stocks dampening the downward behavior of otherwise less diversified portfolio returns in down markets.

Therefore, some suggest that *de*regulation may have ''buffered'' utility cash flows from regulatory risk, i.e., the chance that regulation would impose disappointing allowed rates of return in the manner described above. The advent of generation deregulation caused electric utilities with generating plants to no longer face regulatory risk on over 50 percent of their asset base. This is consistent with falling betas after deregulation of electric generation. The Brattle Group in 2004[18] found the same result in a research project for the Edison Electric Institute, an electric utility trade and lobbying organization. They found that electric utility betas fell after deregulation.

We suggest that it may be due to the relief of deregulation from asymmetric regulation. In any case, we find that the Blume adjustment toward 1 is not supported by our empirical results. This adjustment suggests that in the long run, all public utilities (and all firms) would gravitate toward the same risk and return. Our results herein suggest that the Blume adjustment is inappropriate for public utilities as it assumes that public utility betas are moving toward one in the long run as are non-utility company betas.

We perform a simple calculation to show the impact of a biased beta on public utility revenues. We calculate the common equity risk premium on the market as the annual total return for the CRSP market return from 1926 to 2007 to be approximately 12 percent and the average return on a three-month T-Bill to be about 4 percent. The long-term common equity risk premium is 8 percent. The difference between a beta of 0.50 and a Blume adjusted beta of .67 would result in a difference in cost of common equity

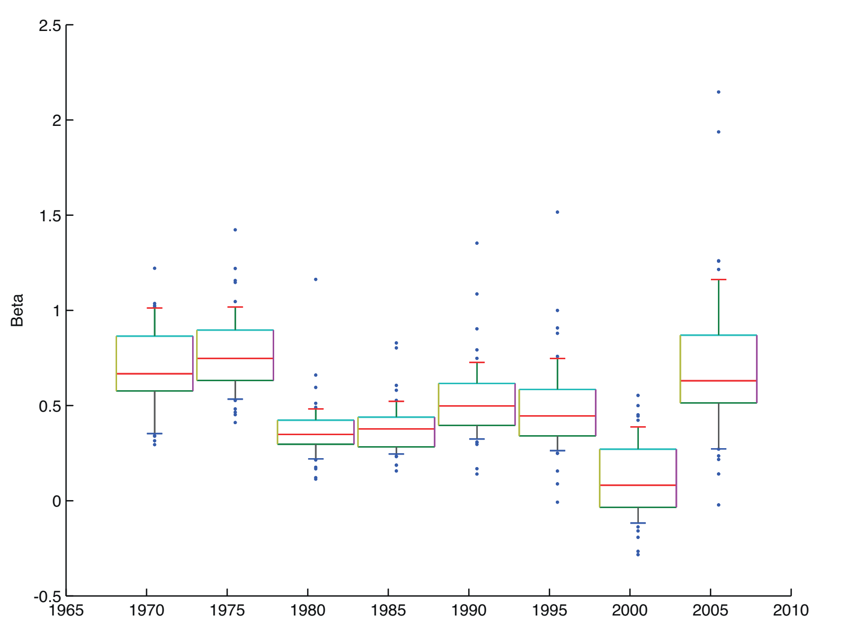

Figure 2: Boxplots of Utility Stock Betas Using 5 Year Periods Data

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of 136 basis points. Using a common equity ratio of 0.50, this would impact the weighted average rate of return by 68 points. Assuming a rate base of $5 billion (the level for a moderately large electric utility), the difference in ''allowed'' net income would be 0.0068 × $5 billion, or, $34 million. Assuming a 37.5 percent income tax rate, the increase in revenues required to earn the additional $34 million would be $54 million. This is obviously a substantial difference. It is important for us to stress in this example that we do not necessarily advocate these inputs for the recommended cost of common equity for a utility with a raw beta of 0.50. The deliberation in recommending the cost of common equity is performed with a careful and detailed analysis of the company and stock, referral to more than one valuation model of the cost of common equity estimation and expert judgment.

IV. Conclusion

Major vendors of CAPM betas such as Merrill Lynch, Value Line, and Bloomberg distribute Blume-adjusted betas to investors. We have shown empirically that public utility betas do not have a tendency to converge to 1. Short-term betas of public utilities follow a cyclical pattern with recent downward trends, then upward structural breaks with long-term betas following a downward trend. We estimate the Blume equation for electric and gas public utilities, finding that all but one equation is statistically insignificant. The single significant equation implies a long-term convergence of beta to approximately 0.59. During our nearly 45-year study period, the median beta ranged from 0.08 to 0.74. Therefore the Blume equation overpredicts utility betas and Blume-adjustments

of utility betas are not appropriate.

We are not suggesting that betas should not be adjusted for prediction. Rather, the measurement period and subjective adjustment to beta should be based upon the likely future trend in peer group or *public utility betas*, or the specific utility's beta, not the trend in betas for all stocks in general. The time pattern of utility betas is obviously more complex than a smooth curvilinear adjustment, or for that matter, any adjustment toward one. Nor do we suggest as an alternative the use of raw or unadjusted betas in an application of the CAPM to estimate a public utility's cost of common equity.■

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