CORNING NATURAL GAS CORPORATION
RATE OF RETURN REQUIRED FOR:
TWELVE MONTHS ENDING JANUARY 31, 2022

	Average Capitalization $	Average Capitalization %	Cost Rate %	Weighted Cost Rate %	Pre-Tax Cost Rate %
Long Term Debt	$ 28,411,903	41.17%	3.91%	1.61%	1.61%
Short Term Debt	$ 8,656,887	12.54%	3.78%	0.47%	0.47%
Customer Deposits	$ 200,148	0.29%	0.90%	0.00%	0.00%
Common Equity	$ 31,747,614	46.00%	8.45%	3.89%	5.26%
Total Capitalization	$ 69,016,552	100.00%		5.97%	7.35%

CORNING NATURAL GAS CORPORATION

Long-Term Debt

Forecast - Rate Year Ended January 31, 2022

Index of Corning's Long Term Debts

	Loan Number	Issued Date	Total Amount	Interest Rate
2017 Consolidation	Loan 1	11/30/2017	29,000,000	4.16%
2018 Vehicles	Loan 2	11/30/2018	150,000	5.83%
2018 CapEx	Loan 3	11/30/2018	3,600,000	4.71%
2019 Vehicles	Loan 4	11/30/2019	123,865	5.06%
(Future Borrowing)	Loan 5	11/30/2020	2,782,975	2.46%
(Future Borrowing)	Loan 6	11/30/2021	3,121,526	2.46%
2019 CapEx*	N/A	10/31/2019	3,127,000	3.53%
2020 Vehicles*	N/A	11/15/2020	300,000	3.26%
2020 PPP Loan*	N/A	4/1/2020	970,000	1.00%

* Company neglected to include these loans in revenue requirement model.
Staff's finance adjustments reflect inclusion of these loans.

CORNING NATURAL GAS CORPORATION
Long-Term Debt
Forecast - Rate Year Ended January 31, 2022

Monthly Fixed Interest Payments

Month & Year	Total	Loan1	Loan2	Loan3	Loan4	Loan5	Loan6	2019 CapEx	2020 Vehicles	2020 PPP
2021, February	100,524.91	73,086.76	215.34	11,605.53	328.53	5,621.05	-	8,218.09	771.78	677.83
2021, March	99,439.39	72,314.62	194.28	11,503.20	314.24	5,578.89	-	8,151.18	750.08	632.90
2021, April	98,350.26	71,539.79	173.11	11,400.48	299.90	5,536.65	-	8,084.06	728.33	587.94
2021, May	97,257.49	70,762.29	151.83	11,297.35	285.50	5,494.32	-	8,016.75	706.51	542.94
2021, June	96,161.08	69,982.08	130.46	11,193.81	271.03	5,451.91	-	7,949.25	684.63	497.90
2021, July	95,061.00	69,199.17	108.98	11,089.87	256.51	5,409.41	-	7,881.54	662.70	452.83
2021, August	93,957.26	68,413.55	87.39	10,985.53	241.92	5,366.82	-	7,813.63	640.70	407.71
2021, September	92,849.83	67,625.20	65.70	10,880.77	227.27	5,324.14	-	7,745.53	618.65	362.56
2021, October	91,738.71	66,834.12	43.91	10,775.60	212.57	5,281.38	-	7,677.22	596.54	317.38
2021, November	90,623.88	66,040.30	22.01	10,670.02	197.79	5,238.53	-	7,608.72	574.36	272.15
2021, December	95,904.45	65,243.73	-	10,564.02	182.96	5,195.59	6,399.13	7,540.01	552.13	226.89
2022, January	94,757.18	64,444.39	-	10,457.61	168.06	5,152.56	6,352.04	7,471.10	529.83	181.58
Total	1,146,625.43	825,486.01	1,193.00	132,423.78	2,986.29	64,651.23	12,751.17	94,157.08	7,816.25	5,160.62

Monthly Fixed Rate Loan Balances

Month & Year	Total	Loan1	Loan2	Loan3	Loan4	Loan5	Loan6	CapEx	Vehicles	PPP
2021, February	30,794,924.86	21,082,719.88	44,324.46	2,956,821.77	77,911.34	2,741,974.24	-	2,793,685.51	284,090.86	813,396.79
2021, March	30,433,188.35	20,859,985.50	39,988.06	2,930,751.97	74,524.18	2,721,410.80	-	2,770,938.03	276,103.86	759,485.96
2021, April	30,070,366.33	20,636,478.96	35,630.59	2,904,579.85	71,122.74	2,700,805.20	-	2,748,123.63	268,095.16	705,530.20
2021, May	29,706,455.18	20,412,197.61	31,251.95	2,878,305.00	67,706.96	2,680,157.36	-	2,725,242.12	260,064.71	651,529.47
2021, June	29,341,451.25	20,187,138.74	26,852.03	2,851,927.02	64,276.78	2,659,467.20	-	2,702,293.30	252,012.44	597,483.75
2021, July	28,975,350.92	19,961,299.67	22,430.74	2,825,445.51	60,832.13	2,638,734.62	-	2,679,276.97	243,938.29	543,392.99
2021, August	28,608,150.51	19,734,677.69	17,987.97	2,798,860.05	57,372.95	2,617,959.54	-	2,656,192.94	235,842.21	489,257.15
2021, September	28,239,846.36	19,507,270.09	13,523.62	2,772,170.25	53,899.19	2,597,141.86	-	2,633,041.00	227,724.13	435,076.20
2021, October	27,870,434.78	19,279,074.15	9,037.58	2,745,375.70	50,410.79	2,576,281.52	-	2,609,820.95	219,584.01	380,850.10
2021, November	27,499,912.07	19,050,087.12	4,529.74	2,718,475.97	46,907.67	2,555,378.41	-	2,586,532.60	211,421.76	326,578.81
2021, December	30,249,800.54	18,820,306.27	-	2,691,470.66	43,389.78	2,534,432.44	3,121,526.00	2,563,175.74	203,237.34	272,262.29
2022, January	29,858,625.47	18,589,728.85	-	2,664,359.36	39,857.06	2,513,443.54	3,098,555.28	2,539,750.17	195,030.69	217,900.51
Average	29,304,042.22	19,843,413.71	20,463.06	2,811,545.26	59,017.63	2,628,098.89	518,340.11	2,667,339.41	239,762.12	516,062.02

CORNING NATURAL GAS CORPORATION
Long-Term Debt
Forecast - Rate Year Ended January 31, 2022

Rate Year Embedded Cost of Long Term Debt	
Month & Year	**Monthly Weighted Average Interest Rate**
2021, February	3.92%
2021, March	3.92%
2021, April	3.92%
2021, May	3.93%
2021, June	3.93%
2021, July	3.94%
2021, August	3.94%
2021, September	3.95%
2021, October	3.95%
2021, November	3.95%
2021, December	3.80%
2022, January	3.81%
Average	3.91%

CORNING NATURAL GAS CORPORATION
Stand-Alone Capital Structure, with Staff Corrections
Forecast - Rate Year Ended January 31, 2022

	Amount Outstanding	Adjustment	Amount As Adjusted	Ratio
Long Term Debt	$ 31,011,213	$ -	$ 31,011,213	41.97%
Short Term Debt	8,656,887	-	8,656,887	11.72%
Total Debt	$ 39,668,100	$ -	$ 39,668,100	
Customer Deposit	200,148	-	200,148	0.27%
Common Equity	34,024,152	-	34,024,152	46.05%
Total Capital	$ 73,892,400	$ -	$ 73,892,400	100.00%

CORNING NATURAL GAS CORPORATION
Stand-Alone Capital Structure, with Staff Adjustments
Forecast - Rate Year Ended January 31, 2022

	Amount Outstanding	Adjustment	Amount As Adjusted	Ratio
Long Term Debt	$ 31,933,509	$ -	$ 31,933,509	42.88%
Short Term Debt	8,656,887	-	8,656,887	11.63%
Total Debt	$ 40,590,396	$ -	$ 40,590,396	
Customer Deposit	200,148	-	200,148	0.27%
Common Equity	33,676,365	-	33,676,365	45.22%
Total Capital	$ 74,466,909	$ -	$ 74,466,909	100.00%

CORNING NATURAL GAS CORPORATION
Consolidated Capital Structure, Corning Natural Gas Holding Corporation
Forecast - Rate Year Ended January 31, 2022

	Amount Outstanding	Adjustment	Amount As Adjusted	Ratio
Long Term Debt	$ 47,481,243	$ -	$ 47,481,243	43.90%
Short Term Debt	9,307,910	-	9,307,910	8.61%
Total Debt	$ 56,789,153	$ -	$ 56,789,153	
Customer Deposit	304,537	-	304,537	0.28%
Preferred Equity	14,739,417	-	14,739,417	13.63%
Common Equity	36,325,391	-	36,325,391	33.59%
Total Capital	$ 108,158,497	$ -	$ 108,158,497	100.00%

Staff Proxy Group: Credit Ratings and Regulated Revenues

No.	Company Name	Ticker	S&P Credit Ratings	S&P Rank	Moody's Credit Ratings	Moody's Rank	2019 ($M) Regulated Utility Revenue	2019 ($M) Total Revenue	2019 % Utility Revenue
1	Allete Inc	ALE	BBB	9	Baa1	8	1,042	1,241	84.0%
2	Alliant Energy Corp	LNT	A-	7	Baa2	9	3,519	3,648	96.5%
3	Ameren Corp	AEE	BBB+	8	Baa1	8	5,910	5,910	100.0%
4	American Electric Power Co. Inc	AEP	A-	7	Baa1	8	13,565	15,561	87.2%
5	Atmos Energy Corp	ATO	A	6	A1	5	2,745	2,902	94.6%
6	Avista Corp	AVA	BBB	9	Baa2	9	1,333	1,346	99.0%
7	Black Hills Corp	BKH	BBB+	8	Baa2	9	1,723	1,735	99.3%
8	CMS Energy Corp	CMS	BBB+	8	Baa1	8	6,376	6,845	93.1%
9	Consolidated Edison Inc	ED	A-	7	Baa2	9	11,712	12,574	93.1%
10	Dominion Energy	D	BBB+	8	Baa2	9	12,826	16,572	77.4%
11	Duke Energy Corp	DUK	A-	7	Baa1	8	24,697	25,079	98.5%
12	Edison International	EIX	BBB	9	Baa3	10	12,306	12,347	99.7%
13	Entergy Corp	ETR	BBB+	8	Baa2	9	9,583	10,878	88.1%
14	Eversource Energy	ES	A-	7	Baa1	8	8,526	8,526	100.0%
15	FirstEnergy Corp	FE	BBB	9	Baa3	10	10,805	11,035	97.9%
16	Hawaiian Electric Industries Inc	HE	BBB-	10	Baa2*	9	2,546	2,875	88.6%
17	IDACORP Inc	IDA	BBB	9	Baa1	8	1,343	1,346	99.7%
18	MGE Energy Inc	MGEE	AA-*	4	A1*	5	568	569	99.9%
19	NextEra Energy Inc	NEE	A-	7	Baa1	8	13,679	19,204	71.2%
20	Nisource Inc	NI	BBB+	8	Baa2	9	4,035	5,209	77.5%
21	Northwest Natural Holding Co.	NWN	A+*	5	(P)Baa1*	8	729	746	97.7%
22	NorthWestern Corp.	NWE	BBB	9	Baa2	9	940	940	100.0%
23	OGE Energy Corp	OGE	BBB+	8	(P)Baa1	8	2,232	2,232	100.0%
24	ONE Gas Inc.	OGS	A	6	A2	6	1,653	1,653	100.0%
25	Pinnacle West Capital Corp	PNW	A-	7	A3	7	3,333	3,471	96.0%
26	PNM Resources Inc	PNM	BBB	9	Baa3	10	1,377	1,458	94.4%
27	Portland General Electric Co.	POR	BBB+	8	A3	7	1,953	2,123	92.0%
28	PPL Corp.	PPL	A-	7	Baa2	9	7,731	7,769	99.5%
29	Sempra Energy	SRE	BBB+	8	Baa2	9	10,636	10,829	98.2%
30	Southern Co	SO	A-	7	Baa2	9	17,876	21,419	83.5%
31	Spire Inc.	SR	A-	7	Baa2	9	1,861	1,952	95.3%
32	WEC Energy Group	WEC	A-	7	Baa1	8	3,068	3,138	97.8%
33	Xcel Energy Inc	XEL	A-	7	Baa1	8	10,706	11,529	92.9%
	Average (All) and Totals		BBB+	7.6	Baa1	8.3	212,934	234,661	93.7%

Percentage of Unregulated Revenues	6.3%

Company Witnesses Proxy Group: Credit Ratings and Regulated Revenues
Combination Proxy Group

No.	Company Name	Ticker	S&P Credit Ratings	S&P Rank	Moody's Credit Ratings	Moody's Rank	2019 ($M) Regulated Utility Revenue	2019 ($M) Total Revenue	2019 % Utility Revenue
1	Allete Inc	ALE	BBB	9	Baa1	8	1,042	1,241	84.0%
2	American Electric Power Co. Inc	AEP	A-	7	Baa1	8	13,565	15,561	87.2%
3	Atmos Energy Corp	ATO	A	6	A1	5	2,745	2,902	94.6%
4	Avista Corp	AVA	BBB	9	Baa2	9	1,333	1,346	99.0%
5	Black Hills Corp	BKH	BBB+	8	Baa2	9	1,723	1,735	99.3%
6	CMS Energy Corp	CMS	BBB+	8	Baa1	8	6,376	6,845	93.1%
7	Consolidated Edison Inc	ED	A-	7	Baa2	9	11,712	12,574	93.1%
8	Edison International	EIX	BBB	9	Baa3	10	12,306	12,347	99.7%
9	Exelon Corp	EXC	BBB+	8	Baa2	9	16,684	34,438	48.4%
10	Hawaiian Electric Industries Inc	HE	BBB-	10	Baa2*	9	2,546	2,875	88.6%
11	New Jersey Resources Corp	NJR	NR	NA	A1*	5	711	2,592	27.4%
12	Northwest Natural Holding Co.	NWN	A+*	5	(P)Baa1*	8	729	746	97.7%
13	NorthWestern Corp.	NWE	BBB	9	Baa2	9	940	940	100.0%
14	ONE Gas Inc.	OGS	A	6	A2	6	1,653	1,653	100.0%
15	Otter Tail Corp	OTTR	BBB	9	Baa2	9	459	920	49.9%
16	Portland General Electric Co.	POR	BBB+	8	A3	7	1,953	2,123	92.0%
17	PPL Corp.	PPL	A-	7	Baa2	9	7,731	7,769	99.5%
18	Public Service Enterprise Group In	PEG	BBB+	8	Baa1	8	6,625	10,076	65.8%
19	Sempra Energy	SRE	BBB+	8	Baa1	8	10,636	10,829	98.2%
20	South Jersey Industries Inc	SJI	BBB	9	A3*	7	897	1,629	55.1%
21	Southwest Gas Holdings Inc.	SWX	BBB+	8	Baa1	8	1,369	3,120	43.9%
22	Spire Inc.	SR	A-	7	Baa2	9	1,861	1,952	95.3%
23	Xcel Energy Inc	XEL	A-	7	Baa1	8	10,706	11,529	92.9%
	Average (All) and Totals		BBB+	7.8	Baa1	8.0	116,302	147,742	82.8%
					Percentage of Unregulated Revenues				17.2%

Company Witnesses Proxy Group: Credit Ratings and Regulated Revenues
Natural Gas Proxy Group

No.	Company Name	Ticker	S&P Credit Ratings	S&P Rank	Moody's Credit Ratings	Moody's Rank	2019 ($M) Regulated Utility Revenue	2019 ($M) Total Revenue	2019 % Utility Revenue
1	Atmos Energy Corp	ATO	A	6	A1	5	2,745	2,902	94.6%
2	New Jersey Resources Corp	NJR	NR	NA	A1*	5	711	2,592	27.4%
3	Northwest Natural Holding Co.	NWN	A+*	5	(P)Baa1*	8	729	746	97.7%
4	ONE Gas Inc.	OGS	A	6	A2	6	1,653	1,653	100.0%
5	South Jersey Industries Inc	SJI	BBB	9	A3*	7	897	1,629	55.1%
6	Southwest Gas Holdings Inc.	SWX	BBB+	8	Baa1	8	1,369	3,120	43.9%
7	Spire Inc.	SR	A-	7	Baa2	9	1,861	1,952	95.3%
	Average (All) and Totals		A-	6.8	A3	6.9	9,965	14,594	73.4%
					Percentage of Unregulated Revenues				26.6%

Company Witnesses two Proxy Group average percentage of unregulated revenues	21.9%

Proxy Group: Credit Ratings and Regulated Revenues
Value Line Universe of Electric and Gas Utilities

No.	Company Name	Ticker	S&P Credit Ratings	S&P Rank	Moody's Credit Ratings	Moody's Rank	2019 ($M) Regulated Utility Revenue	2019 ($M) Total Revenue	2019 % Utility Revenue	Reason for Exclusion from Proxy Group
	Electric Utility Industry (East)[1] February 13, 2020									
1	Avangrid Inc	AGR	BBB+	8	Baa1	8	4,964	6,338	78.3%	Dividends under 5 yrs
2	Consolidated Edison Inc	ED	A-	7	Baa2	9	11,712	12,574	93.1%	
3	Dominion Energy	D	BBB+	8	Baa2	9	12,826	16,572	77.4%	
4	Duke Energy Corp	DUK	A-	7	Baa1	8	24,697	25,079	98.5%	
5	Eversource Energy	ES	A-	7	Baa1	8	8,526	8,526	100.0%	
6	Exelon Corp	EXC	BBB+	8	Baa2	9	16,684	34,438	48.4%	Regulated Revenue
7	FirstEnergy Corp	FE	BBB	9	Baa3	10	10,805	11,035	97.9%	
8	NextEra Energy Inc	NEE	A-	7	Baa1	8	13,679	19,204	71.2%	
9	PPL Corp.	PPL	A-	7	Baa2	9	7,731	7,769	99.5%	
10	Public Service Enterprise Group Inc	PEG	BBB+	8	Baa1	8	6,625	10,076	65.8%	Regulated Revenue
11	Southern Co	SO	A-	7	Baa2	9	17,876	21,419	83.5%	
	Electric Utility Industry (Central)[2] February 13, 2020									
12	Allete Inc	ALE	BBB	9	Baa1	8	1,042	1,241	84.0%	
13	Alliant Energy Corp	LNT	A-	7	Baa2	9	3,519	3,648	96.5%	
14	Ameren Corp	AEE	BBB+	8	Baa1	8	5,910	5,910	100.0%	
15	American Electric Power Co. Inc	AEP	A-	7	Baa1	8	13,565	15,561	87.2%	
16	CenterPoint Energy Inc	CNP	BBB+	8	Baa2	9	7,162	12,301	58.2%	Regulated Revenue
17	CMS Energy Corp	CMS	BBB+	8	Baa1	8	6,376	6,845	93.1%	
18	DTE Energy Co.	DTE	BBB+	8	Baa2	9	6,638	12,669	52.4%	Regulated Revenue
19	Entergy Corp	ETR	BBB+	8	Baa2	9	9,583	10,878	88.1%	
20	Evergy Inc.	EVRG	A-	7	Baa2	9	4,358	5,147	84.7%	Lacks Value Line beta
21	Fortis Inc.	FTS	A-	7	Baa3	10	8,704	8,783	99.1%	Foreign Company
22	MGE Energy Inc	MGEE	AA-*	4	A1*	5	568	569	99.9%	
23	OGE Energy Corp	OGE	BBB+	8	(P)Baa1	8	2,232	2,232	100.0%	
24	Otter Tail Corp	OTTR	BBB	9	Baa2	9	459	920	49.9%	Regulated Revenue
25	WEC Energy Group	WEC	A-	7	Baa1	8	3,068	3,138	97.8%	
	Electric Utility Industry (West)[3] Feb 13, 2020									
26	Avista Corp	AVA	BBB	9	Baa2	9	1,333	1,346	99.0%	
27	Black Hills Corp	BKH	BBB+	8	Baa2	9	1,723	1,735	99.3%	
28	Edison International	EIX	BBB	9	Baa3	10	12,306	12,347	99.7%	
29	El Paso Electric Co.	EE	BBB	9	Baa2	9	726	862	84.2%	Acquisition
30	Hawaiian Electric Industries Inc	HE	BBB-	10	Baa2*	9	2,546	2,875	88.6%	
31	IDACORP Inc	IDA	BBB	9	Baa1	8	1,343	1,346	99.7%	
32	NorthWestern Corp.	NWE	BBB	9	Baa2	9	940	940	100.0%	
33	PG&E Corp.	PCG	NR	NA	WR	NA	17,129	17,129	100.0%	Credit Rating
34	Pinnacle West Capital Corp	PNW	A-	7	A3	7	3,333	3,471	96.0%	
35	PNM Resources Inc	PNM	BBB	9	Baa3	10	1,377	1,458	94.4%	
36	Portland General Electric Co.	POR	BBB+	8	A3	7	1,953	2,123	92.0%	
37	Sempra Energy	SRE	BBB+	8	Baa2	9	10,636	10,829	98.2%	
38	Xcel Energy Inc	XEL	A-	7	Baa1	8	10,706	11,529	92.9%	

Value Line Universe of Electric and Gas Utilities Ratings and Regulated Revenues

	Gas Utility Industry[4] February 13, 2020									
39	Atmos Energy Corp	ATO	A	6	A1	5	2,745	2,902	94.6%	
40	New Jersey Resources Corp	NJR	NR	NA	A1*	5	711	2,592	27.4%	Regulated Revenue
41	Nisource Inc	NI	BBB+	8	Baa2	9	4,035	5,209	77.5%	
42	Northwest Natural Holding Co.	NWN	A+*	5	(P)Baa1*	Baa1	729	746	97.7%	
43	ONE Gas Inc.	OGS	A	6	A2	6	1,653	1,653	100.0%	
44	South Jersey Industries Inc	SJI	BBB	9	A3*	7	897	1,629	55.1%	Regulated Revenue
45	Southwest Gas Holdings Inc.	SWX	BBB+	8	Baa1	8	1,369	3,120	43.9%	Regulated Revenue
46	Spire Inc.	SR	A-	7	Baa2	9	1,861	1,952	95.3%	
47	UGI Corp	UGI	NR	NA	NR	NA	981	7,320	13.4%	Regulated Revenue
	Average (All) and Totals		BBB+	7.7	Baa1	8.3	290,341	357,986	84.1%	

Source: Value Line

1 Electric Utility (East) (as of 2-13-20)
2 Electric Utility (Central) (as of 2-13-20)
3 Electric Utility (West) (as of 2-13-20)
4 Natural Gas Utility (as of 2-13-20)

Credit Ratings are as of May 9, 2020
* Credit Ratings of subsidiary

Credit Rating Grade	S&P Credit Rating	Moody's Credit Rating	Credit Score
Investment	AAA	Aaa	1
Investment	AA+	Aa1	2
Investment	AA	Aa2	3
Investment	AA-	Aa3	4
Investment	A+	A1	5
Investment	A	A2	6
Investment	A-	A3	7
Investment	BBB+	Baa1	8
Investment	BBB	Baa2	9
Investment	BBB-	Baa3	10

Staff Proxy Group
Capital Structure & Equity Ratio for Fiscal Year 2019

	Company	Ticker	Short-term Debt	Current Portion of LTD	Long-term Debt (LTD)	Customer Deposits	Preferred Stock	Common Equity (CE)	Minority Interest	Total Capitalization	Equity Ratio %
1	Allete, Inc	ALE	$0	$213	$1,401	$0	$0	$2,232	$104	$3,949	59.14%
2	Alliant Energy Corp.	LNT	$337	$657	$5,533	$0	$200	$5,205	$0	$11,933	45.30%
3	Ameren Corp.	AEE	$440	$442	$8,915	$0	$0	$8,059	$142	$17,998	45.57%
4	American Electric Power	AEP	$2,838	$1,599	$25,127	$366	$0	$19,632	$281	$49,843	39.95%
5	Atmos Energy	ATO	$465	$0	$3,529	$0	$0	$5,750	$0	$9,745	59.01%
6	Avista Corp.	AVA	$186	$52	$1,844	$0	$0	$1,939	$0	$4,021	48.23%
7	Black Hills Corp.	BKH	$350	$6	$3,140	$0	$0	$2,362	$102	$5,959	41.35%
8	CMS Energy Corp.	CMS	$90	$1,130	$11,951	$0	$0	$5,018	$37	$18,226	27.74%
9	Consolidated Edison	ED	$1,692	$1,446	$18,527	$346	$0	$18,022	$191	$40,224	45.28%
10	Dominion Energy	D	$911	$3,162	$33,824	$0	$2,387	$29,607	$2,039	$71,930	47.31%
11	Duke Energy Corp.	DUK	$3,135	$3,141	$54,985	$0	$1,962	$44,860	$1,129	$109,212	43.91%
12	Edison International	EIX	$505	$479	$17,864	$302	$0	$13,303	$2,193	$34,646	44.73%
13	Entergy Corp.	ETR	$1,947	$795	$17,079	$409	$35	$10,224	$0	$30,488	33.65%
14	Eversource	ES	$889	$327	$13,771	$0	$156	$12,630	$0	$27,773	46.04%
15	FirstEnergy Corp.	FE	$1,000	$380	$19,618	$0	$0	$6,975	$0	$27,973	24.93%
16	Hawaiian Electric Industries Inc	HE	$186	$0	$1,964	$0	$34	$2,280	$0	$4,465	51.84%
17	IDACORP, Inc.	IDA	$111	$100	$1,737	$0	$0	$2,465	$6	$4,418	55.92%
18	MGE Energy, Inc.	MGEE	$0	$20	$524	$0	$0	$856	$0	$1,399	61.16%
19	NextEra Energy, Inc.	NEE	$2,916	$2,124	$37,543	$0	$0	$37,005	$4,842	$84,430	49.56%
20	NiSource Inc.	NI	$1,773	$13	$7,856	$0	$880	$5,987	$0	$16,510	41.59%
21	Northwest Natural Holding Co.	NWN	$149	$75	$806	$0	$0	$866	$0	$1,896	45.67%
22	NorthWestern Corp.	NWE	$0	$2	$2,233	$0	$0	$2,039	$0	$4,275	47.70%
23	OGE Energy Corp.	OGE	$112	$0	$3,195	$83	$0	$4,140	$0	$7,530	54.98%
24	One Gas, Inc.	OGS	$517	$0	$1,286	$58	$0	$2,129	$0	$3,990	53.37%
25	Pinnacle West Capital	PNW	$115	$800	$4,833	$65	$0	$5,431	$123	$11,365	48.86%
26	PNM Resources	PNM	$185	$490	$2,517	$11	$12	$1,679	$63	$4,957	35.37%
27	Portland General Electric	POR	$0	$16	$2,597	$0	$0	$2,591	$0	$5,204	49.79%
28	PPL Corp.	PPL	$1,151	$1,172	$20,721	$261	$0	$12,991	$0	$36,296	35.79%
29	Sempra Energy	SRE	$3,505	$1,526	$20,785	$0	$20	$19,929	$1,856	$47,621	45.79%
30	Southern Co.	SO	$2,055	$2,989	$41,798	$496	$291	$27,505	$4,254	$79,388	40.37%
31	Spire Inc.	SR	$743	$40	$2,083	$36	$242	$2,301	$0	$5,445	46.71%
32	WEC Energy Group	WEC	$831	$693	$11,211	$0	$30	$10,113	$111	$22,990	44.61%
33	Xcel Energy, Inc.	XEL	$595	$702	$17,407	$0	$0	$13,239	$0	$31,943	41.45%
	Total		*$29,728*	*$24,592*	*$418,204*	*$2,433*	*$6,249*	*$339,363*	*$17,472*	*$838,041*	
	Average		**$901**	**$745**	**$12,673**	**$74**	**$189**	**$10,284**	**$529**	**$25,395**	**45.53%**
	Median		$505	$442	$7,856	$0	$0	$5,750	$0	$16,510	45.67%

Source:
2019 Annual reports (10K)

Discount Cash Flow Model
Electric and Gas Proxy Group

	(B) Company[1]	Ticker	(C) Beta[2]	(D) Stock Price[3] Mar-May 2020	(E) EPS 2024	(F) DPS 2020	(G) DPS 2021	(H) DPS 2024	(I) BPS 2020	(J) BPS 2021	(K) BPS 2024	(L) Number of Shares 2020	(M) Number of Shares 2024
1.	Allete Inc	ALE	0.85	58.59	4.25	2.47	2.58	2.90	46.30	47.65	51.75	52.75	54.25
2.	Alliant Energy Corp	LNT	0.80	47.99	3.00	1.52	1.64	2.00	22.75	24.10	28.25	250.00	265.00
3.	Ameren Corp	AEE	0.80	72.53	4.50	2.01	2.11	2.45	35.70	37.40	43.50	254.00	275.00
4.	American Electric Power Co. In	AEP	0.75	81.23	5.25	2.84	3.00	3.55	41.30	43.00	50.00	495.00	530.00
5.	Atmos Energy Corp	ATO	0.80	98.33	6.00	2.30	2.46	3.00	52.80	55.40	66.20	125.00	145.00
6.	Avista Corp	AVA	0.60	41.11	2.50	1.62	1.68	1.90	29.45	30.10	32.50	68.70	71.00
7.	Black Hills Corp	BKH	0.65	62.31	4.25	2.17	2.31	2.75	40.60	42.50	47.00	62.75	64.00
8.	CMS Energy Corp	CMS	0.80	57.40	3.50	1.63	1.74	2.15	19.35	20.70	25.50	287.00	300.00
9.	Consolidated Edison Inc	ED	0.75	78.27	5.00	3.06	3.16	3.50	55.75	57.60	62.75	343.00	365.00
10.	Dominion Energy	D	0.80	76.17	5.50	3.76	3.86	4.15	34.45	35.05	39.75	842.00	880.00
11.	Duke Energy Corp	DUK	0.85	83.08	6.00	3.82	3.89	4.10	63.80	65.35	71.00	764.00	785.00
12.	Edison International	EIX	0.55	56.52	4.75	2.58	2.68	3.00	39.20	41.20	47.50	375.00	395.00
13.	Entergy Corp	ETR	0.95	98.06	7.00	3.74	3.86	4.55	52.80	55.20	62.75	200.00	212.00
14.	Eversource Energy	ES	0.90	80.89	4.75	2.27	2.40	2.85	40.80	42.65	48.75	339.00	355.00
15.	FirstEnergy Corp	FE	0.85	40.91	3.25	1.57	1.61	1.90	13.40	14.65	20.25	543.00	575.00
16.	Hawaiian Electric Industries Inc	HE	0.55	41.49	2.25	1.32	1.36	1.60	21.75	22.60	25.00	110.00	114.00
17.	IDACORP Inc	IDA	0.50	89.34	5.25	2.73	2.93	3.55	50.65	52.40	57.50	50.40	50.40
18.	MGE Energy Inc	MGEE	0.70	64.00	3.00	1.45	1.52	1.80	27.10	28.30	32.00	36.16	36.16
19.	NextEra Energy Inc	NEE	0.85	233.40	12.50	5.60	6.16	8.20	77.45	81.15	98.75	490.00	495.00
20.	Nisource Inc	NI	0.85	24.26	2.15	0.86	0.92	1.16	13.75	14.25	16.40	383.00	385.00
21.	Northwest Natural Holding Co.	NWN	0.80	61.43	3.50	1.91	1.92	1.97	29.65	31.80	29.85	31.00	32.00
22.	NorthWestern Corp.	NWE	0.55	59.09	4.00	2.40	2.50	2.80	41.55	42.70	45.75	51.00	53.00
23.	OGE Energy Corp	OGE	1.05	30.73	2.50	1.60	1.68	1.95	18.55	19.10	21.00	200.00	200.00
24.	ONE Gas Inc.	OGS	0.80	79.81	4.75	2.16	2.32	2.80	42.10	43.85	49.60	53.00	55.00
25.	Pinnacle West Capital Corp	PNW	0.45	76.83	6.00	3.22	3.41	4.00	49.75	51.35	58.00	112.70	118.00
26.	PNM Resources Inc	PNM	0.55	39.53	2.75	1.24	1.30	1.50	23.40	24.35	29.25	85.83	92.00
27.	Portland General Electric Co.	POR	0.50	47.11	3.00	1.62	1.72	2.05	29.85	30.75	33.75	89.55	90.00
28.	PPL Corp.	PPL	1.05	25.30	2.75	1.66	1.67	1.80	17.75	18.55	21.25	771.00	780.00
29.	Sempra Energy	SRE	0.65	118.86	9.50	4.18	4.50	5.60	72.05	76.65	88.25	300.00	340.00
30.	Southern Co	SO	0.90	55.22	3.75	2.54	2.62	2.86	26.65	27.30	30.75	1060.00	1090.00
31.	Spire Inc.	SR	0.80	71.27	5.15	2.49	2.61	3.00	54.00	59.05	72.00	52.00	55.00
32.	WEC Energy Group	WEC	0.80	88.76	4.75	2.53	2.70	3.20	33.10	34.25	38.25	315.50	315.50
33.	Xcel Energy Inc	XEL	0.45	60.51	3.50	1.72	1.82	2.15	27.20	28.45	32.75	539.00	548.00
	Median:		**0.80**										
	Average:		**0.74**	**69.71**									

Sources:
[1]Value Line Electric Industry Central, as of June 2019.
[1]Value Line Electric Industry East, as of May 2020.
[1]Value Line Electric Industry West, as of April 2020.
[1]Gas Utility Industry, as of May 2020
[2]Beta data is from Value Line Investment Survey.
[3]Historical price data is from Yahoo.com (Yahoo! Finance)

Discount Cash Flow Model
Electric and Gas Proxy Group

	(B) Company[1]	(N) DPS Growth 2024	(O) Retention Rate 2024	(P) Return on Equity 2024	(Q) B x R	(R) S Increase in Shares	(S) V MBR -1 2020	(V) S x V	(W) Sustainable Growth	(X) Long-Form ROE
1.	Allete Inc	3.97	0.32	8.33	2.64	0.70	0.27	0.19	2.83	7.29%
2.	Alliant Energy Corp	6.84	0.33	10.90	3.63	1.47	1.11	1.63	5.26	8.71%
3.	Ameren Corp	5.11	0.46	10.61	4.83	2.01	1.03	2.07	6.90	9.59%
4.	American Electric Power Co. In	5.77	0.32	10.76	3.49	1.72	0.97	1.67	5.15	8.81%
5.	Atmos Energy Corp	6.84	0.50	9.33	4.67	3.78	0.86	3.26	7.93	10.25%
6.	Avista Corp	4.19	0.24	7.79	1.87	0.83	0.40	0.33	2.20	6.43%
7.	Black Hills Corp	5.98	0.35	9.19	3.25	0.49	0.53	0.26	3.51	7.36%
8.	CMS Energy Corp	7.31	0.39	14.20	5.48	1.11	1.97	2.19	7.67	10.56%
9.	Consolidated Edison Inc	3.47	0.30	8.08	2.42	1.57	0.40	0.63	3.06	7.07%
10.	Dominion Energy	2.44	0.25	14.13	3.47	1.11	1.21	1.34	4.81	9.52%
11.	Duke Energy Corp	1.77	0.32	8.57	2.71	0.68	0.30	0.21	2.92	7.42%
12.	Edison International	3.83	0.37	10.24	3.77	1.31	0.44	0.58	4.35	8.94%
13.	Entergy Corp	5.64	0.35	11.39	3.99	1.47	0.86	1.26	5.25	9.12%
14.	Eversource Energy	5.90	0.40	9.96	3.98	1.16	0.98	1.14	5.12	8.06%
15.	FirstEnergy Corp	5.68	0.42	16.91	7.03	1.44	2.05	2.96	9.99	13.41%
16.	Hawaiian Electric Industries Inc	5.57	0.29	9.15	2.64	0.90	0.91	0.81	3.46	6.84%
17.	IDACORP Inc	6.61	0.32	9.27	3.00	0.00	0.76	0.00	3.00	6.51%
18.	MGE Energy Inc	5.80	0.40	9.57	3.83	0.00	1.36	0.00	3.83	6.24%
19.	NextEra Energy Inc	10.00	0.34	13.07	4.50	0.25	2.01	0.51	5.01	7.88%
20.	Nisource Inc	8.03	0.46	13.42	6.18	0.13	0.76	0.10	6.28	10.11%
21.	Northwest Natural Holding Co.	0.86	0.44	11.60	5.07	0.80	1.07	0.85	5.93	8.62%
22.	NorthWestern Corp.	3.85	0.30	8.84	2.65	0.97	0.42	0.41	3.06	7.31%
23.	OGE Energy Corp	5.09	0.22	12.09	2.66	0.00	0.66	0.00	2.66	8.35%
24.	ONE Gas Inc.	6.47	0.41	9.77	4.01	0.93	0.90	0.83	4.85	7.78%
25.	Pinnacle West Capital Corp	5.46	0.33	10.55	3.52	1.16	0.54	0.63	4.15	8.63%
26.	PNM Resources Inc	4.89	0.45	9.69	4.40	1.75	0.69	1.21	5.61	8.76%
27.	Portland General Electric Co.	6.03	0.32	9.03	2.86	0.13	0.58	0.07	2.93	6.79%
28.	PPL Corp.	2.53	0.35	13.23	4.57	0.29	0.43	0.12	4.70	10.87%
29.	Sempra Energy	7.56	0.41	11.02	4.52	3.18	0.65	2.07	6.59	10.34%
30.	Southern Co	2.96	0.24	12.44	2.95	0.70	1.07	0.75	3.70	8.29%
31.	Spire Inc.	4.75	0.42	7.39	3.08	1.41	0.32	0.45	3.54	7.24%
32.	WEC Energy Group	5.83	0.33	12.65	4.13	0.00	1.68	0.00	4.13	7.22%
33.	Xcel Energy Inc	5.71	0.39	10.94	4.22	0.41	1.22	0.51	4.73	7.73%
	Median:								**4.70**	**8.29%**
	Average:	**5.23**							**4.70**	**8.43%**

Cost of Equity Calculation

Staff Electric and Gas Proxy Group

Cost of Market[1]:	*Implied*	*Required*
March 2020	11.00%	10.90%
April 2020	11.00%	10.80%
May 2020	10.40%	10.30%
Cost of Market	10.73%	

Treasury Rates[2]:	*10 year*	*30 year*
March 2020	0.87%	1.46%
April 2020	0.66%	1.27%
May 2020	0.67%	1.38%
Risk Free Rate	1.05%	

Market Risk Premium (MRP): 9.68%

Proxy Group Beta	0.74	
Traditional CAPM ROE	8.24%	
Zero Beta CAPM ROE	8.86%	**Average**
Overall CAPM ROE	8.55%	
DCF ROE	8.43%	

Return on Equity 2/3 DCF 1/3 CAPM Weighting	**8.47%**	Average

Sources:

1 Merrill Lynch, Quantitative Profiles Reports - March 2020, April 2020 and May 2020 data; figure is average of Implied and Required Returns for S&P 500.

2 Federal Reserve Statistical Release, FRB: Federal Reserve Statistical Release H.15 - Historical Data

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On Forecasting Long-Term Interest Rates: Is the Success of the No-Change Prediction Surprising?

DR JAMES E. PESANDO*

I. Introduction

IN A RECENT ARTICLE in this Journal, Elliott and Baier [1] provide empirical evidence that the no-change forecast decidedly outperforms the "unconditional predictions" of long-term interest rates associated with the Modigliani-Sutch, Modigliani-Shiller and other well-known models of interest rate determination. The authors use "unconditional predictions" to refer to forecasts generated by variants of these models in which the current long-term rate is regressed on the relevant sets of exogenous variables lagged one period. These regressions—and the subsequent forecasts—are "unconditional" in the sense that they restrict the information set used to track long-term interest rates to that which is known at the beginning of the period.

The crucial issue that the authors do not address, however, is whether the superior forecasting performance of the no-change prediction is or is not surprising on à priori grounds. This issue is of extreme importance in interpreting their findings. One possible interpretation of the Elliott-Baier results, for example, is that the specific information sets associated with the six models are not valuable in a forecasting context, but other information sets may be. In fact, the empirical results reported by Elliott-Baier are not surprising in view of the accumulating evidence that (1) the bond market is efficient and (2) term premiums, if they exist, are time-invariant. These results imply, in effect, that short-term movements in long-term interest rates will not be "forecastable". This important point is reviewed briefly below.

II. The No-Change Prediction: A "Naive" Forecast?

The fact that long-term interest rates will approximately follow a martingale sequence under the conditions described above, and hence that the no-change prediction will approximate the optimal forecast, has been shown by both Sargent (1976) and Pesando (1978). Let $R_{n,t}$ denote the interest rate (for simplicity) on an n-period, non-coupon, bond in period t, ϕ_t the information available to the market in period t, and ${}_{t+i}f_{1,t}$ the forward rate at time t for the one-period bond rate in period $t + i$. Then, under the joint hypothesis of market efficiency and the pure

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expectations model of the term structure, the ex ante changes in the long-term rate can be approximated as follows:

$$E(\tilde{R}_{n,t} \mid \phi_{t-1}) - R_{n,t-1} = \frac{1}{n} * [E({}_{t+n-1}\tilde{f}_{1,t} \mid \phi_{t-1}) - R_{1,t-1}] \tag{1}$$

The term on the right-hand side of equation (1), which represents the nonoverlapping one-period rates, clearly approaches zero as n gets large. In this case, the optimal forecast of the long-term rate is simply its current value; that is, the optimal forecast is the no-change extrapolation. If $\Psi_{n,t}$ represents the term premium accorded an n-period bond in period t, then (1) may be rewritten as:

$$E(\tilde{R}_{n,t} \mid \phi_{t,1}) - R_{n,t-1} = \frac{1}{n} * [E({}_{t+n-1}\tilde{f}_{1,t} \mid \phi_{t-1}) - R_{1,t-1}] + E(\tilde{\psi}_{n,t} \mid \phi_{t-1}) - \psi_{n,t-1} \tag{2}$$

If this term premium is constant, then (2) simply reduces to (1) and the previous result holds.

Elliott-Baier employ monthly data in their forecasting experiments. Assume, for the sake of argument, that the several long-term rates employed in their study have a representative term to maturity of 10 years. (The synthetic series of U.S. Government bonds employed in the study has an exact maturity of 15 years.) If interest rates are expressed at annual rates, then n equals 120 and thus the ex ante change defined in (1) must be very close to zero, unless the short-term rate is "very" nonstationary. Suppose, for example, that $R_{1,t-1}$ equals five per cent (.05) and that $E({}_{t+n-1}\tilde{f}_{1,t} \mid \phi_{t-1})$ equals 10 per cent, which would be consistent with a sharply rising yield curve. The ex ante change in the long-term rate, in spite of the 500 basis point difference in the respective short-term rates, is only 500 ÷ 120 or approximately 4 basis points. Note, by way of contrast, that if the unit of observation were annual rather than monthly, these same figures would imply—since n would equal 10—an ex ante change of more than 40 basis points in the long-term rate. These figures highlight the fact that it is short-run movements in long-term rates which are not likely to be "forecastable" under the joint hypothesis of market efficiency and a time-invariant term premium.

For non-coupon bonds, as noted by Pesando [5] the expression analogous to (1) is more complicated, but the martingale approximation remains quite close. Intuitively, the martingale approximation—and hence the random walk characteristic of long-term rates—stems from the fact that over short time intervals (one month in the case at hand), the percentage change in bond prices necessary to equate the ex ante returns on short- and long-term securities (up to a time-invariant term premium) is very small. As a result, the implied ex ante changes in long-term rates are very close to zero. In a recent paper (Pesando 1979a), I calculated—for quarterly data—the ex ante changes in long-term Government of Canada and long-term Canadian corporate bonds implied by their yields and the yields on 90-day Treasury Bills and 90-day finance company paper, respectively.[1]

[1] For purposes of these calculations, the (assumed) constant term premiums were set equal to the mean spreads between short- and long-term interest rates in the sample period. The representatives terms to maturity for the two interest rate series were assumed to equal 17 years, although complications posed by call options and sinking funds may cloud the interpretation of this figure in the case of corporate bonds.

The mean absolute values of the ex ante changes in these long-term rates for the sample period 1957:1–1979:1 equalled 2.07 basis points and 2.60 basis points, respectively. If monthly data were employed, the corresponding ex ante changes would be approximately one-third as large. With monthly data, the mean absolute values of the ex ante changes in Government of Canada and Canadian corporate bonds would thus be less than a single basis point. Clearly, if the bond market is efficient and if the term premium accorded long-term interest rate is time-invariant, then agents without access to inside information are not likely to be able to forecast short-term movements in long-term interest rates.

III. Conclusion

Those who work in the capital asset pricing framework of modern finance theory tend to treat the term premium—which is related to the covariance of bond returns and the return to the market portfolio—as constant over time. Many—if not most—of those who have conducted empirical studies of the determinants of term premiums have concluded that they may well be time-invariant. In the absence of convincing evidence of the existence of time-varying term premiums, and in view of the strong à priori belief in market efficiency, the success of the "no-change" prediction in the forecasting experiments conducted by Elliott-Baier is not surprising. Short-run movements in long-term interest rates, quite simply, are not likely to be "forecastable". The failure of recorded forecasts to outperform the no-change prediction of the martingale model, in both the United States (Prell [6], Fraser [2]) and Canada (Pesando [3]), is also noteworthy in this regard.

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JUST HOW BAD ARE ECONOMISTS AT PREDICTING INTEREST RATES? (AND WHAT ARE THE IMPLICATIONS FOR INVESTORS?)

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On January 2, 1997, the *Wall Street Journal* published its semiannual survey of economists. Most of the fifty-seven economists surveyed predicted that the yield on the thirty-year Treasury bond, then at 6.64%, would drop by July 1. The consensus estimate for this yield was 6.52%.

Fears of inflation, however, have recently caused interest rates to rise. The yield at the time of this writing in mid-April is over 7%. Thus, barring a major downward shift in interest rates, economists will have wrongly predicted the direction of interest rates.

Some readers will not be surprised by this result, for economists have a notoriously bad reputation for huge forecasting errors. But just how bad are economists at predicting interest rates? And if these experts, whose careers often depend on the accuracy of their predictions, cannot predict interest rates, what are the implications for actively managed bond funds?

I address these questions by analyzing the *Wall Street Journal* survey of economists.

THE DATA AND RESULTS

Economists are employed in nearly all segments of the economy. One of the primary duties of economists in the financial sector is to forecast the economy, or, more specifically, to forecast important economic data such as GDP growth, inflation, and interest rates. Every six months, in late December and late June, the *Wall Street Journal* surveys a group of economists, asking for their forecasts of interest rates, GDP growth, inflation, and the value of the dollar against the yen. The forecasts are published in the first week of January and July.

The participating economists work primarily in the financial sector, most notably investment banks and commercial banks. Only three of the fifty-seven economists participating in the December 1996 survey were then in academia. The number of economists participating has increased steadily from twelve in 1981 to about sixty in the mid-1990s.

The economists have been predicting, six months in advance, the yield on three-month Treasury bills and thirty-year Treasury bonds since December 1981. Each economist provides an estimate for each interest rate, and then a consensus estimate is calculated, which is simply the arithmetic mean of all the estimates.

Can economists predict interest rates? The answer is emphatically "no," regardless of the measure used.

There have been thirty six-month surveys completed since December 1981. The Exhibit provides the consensus estimate and the actual yield for the three-month and thirty-year Treasury securities.

Rates on three-month Treasury bills moved in the *opposite* direction of the consensus prediction in sixteen of these contests (53%). That economists predicted the direction of short-term interest rates correctly almost half of the time is the good news. The bad news is that the consensus estimate for the thirty-year Treasury bond has been in *the wrong direction* in twenty of the thirty contests (67%).

The average error for the consensus estimate is 79 basis points for the Treasury bill, and 86 basis points for the thirty-year bond. Assuming interest rates would stay the same each period yields average errors of 74 and 78 basis points, respectively. Thus, investors who assumed interest rates would remain constant were more accurate than the consensus estimate.

Incorrectly forecasting the direction of interest rates is not very costly for investors if rates move very little. In fact, economists have been least accurate when interest rate changes were largest! The rates on the three-month Treasury bill moved 100 basis points or more on ten occasions. The consensus estimate was in the right direction on six of these occasions, yet the consensus underestimated the move by an average of 99 basis points.

EXHIBIT
WALL STREET JOURNAL CONSENSUS INTEREST RATE FORECAST

	3-Month Treasury Bill			30-Year Treasury Bond		
Date Published	Consensus Forecast (%)	Actual Yield (%)	Correct Direction?	Consensus Forecast (%)	Actual Yield (%)	Correct Direction? (%)
Jan-82	11.06	12.43	Wrong	13.05	13.92	Wrong
Jul-82	11.61	11.08	Right	13.27	13.62	Right
Jan-83	7.37	8.75	Right	10.11	10.98	Right
Jul-83	8.60	8.95	Wrong	10.59	11.87	Wrong
Jan-84	8.72	9.90	Wrong	11.39	13.64	Wrong
Jul-84	10.64	7.84	Wrong	13.78	11.53	Wrong
Jan-85	8.56	6.83	Wrong	11.60	10.44	Wrong
Jul-85	7.31	7.08	Right	10.51	9.27	Wrong
Jan-86	6.96	5.98	Right	9.45	7.28	Wrong
Jul-86	6.14	5.66	Wrong	7.63	7.49	Right
Jan-87	4.98	5.73	Wrong	7.05	8.50	Wrong
Jul-87	5.91	5.67	Wrong	8.45	8.98	Wrong
Jan-88	5.70	6.54	Right	8.65	8.83	Right
Jul-88	6.77	8.09	Right	9.36	8.99	Right
Jan-89	8.29	7.98	Wrong	9.25	8.04	Wrong
Jul-89	7.76	7.79	Right	8.12	7.97	Wrong
Jan-90	7.03	7.98	Wrong	7.62	8.40	Wrong
Jul-90	7.56	6.62	Right	8.16	8.24	Right
Jan-91	6.14	5.62	Right	7.65	8.41	Wrong
Jul-91	5.84	3.93	Wrong	8.22	7.39	Right
Jan-92	3.80	3.63	Right	7.30	7.78	Wrong
Jul-92	3.54	3.15	Right	7.61	7.39	Right
Jan-93	3.41	3.07	Wrong	7.44	6.67	Wrong
Jul-93	3.34	3.05	Wrong	6.84	6.34	Wrong
Jan-94	3.40	4.15	Right	6.26	7.61	Wrong
Jul-94	4.67	5.70	Right	7.30	7.87	Wrong
Jan-95	6.50	5.44	Wrong	7.94	6.62	Wrong
Jul-95	5.45	5.08	Wrong	6.62	5.94	Wrong
Jan-96	4.90	5.15	Wrong	6.00	6.89	Right
Jul-96	5.31	5.19	Right	6.86	6.64	Right
Jan-97	5.10	?	?	6.52	?	?

Again, this is the good news. The yield on the thirty-year bond has moved more than 100 basis points on ten occasions. The consensus estimate was in the *wrong direction* on eight of these occasions. One of the two correct guesses was a consensus estimate of a 19-basis point drop when rates dropped 102 basis points. Economists therefore essentially missed on nine of the ten biggest interest rate movements in the last fourteen years.

The survey data from the *Wall Street Journal* clearly show that economists a group cannot predict interest rates. Might there be some individual economists, however, who can successfully predict interest rates? Further analysis suggests everyone is almost equally inaccurate.

Forty-four economists have participated in ten or more contests. Of these, only thirteen participants guessed the right direction of long-term interest rates more than 50% of the time; none of these professionals exceeded a 60% accuracy rate.[1] The median accuracy rate is 44%. The figures are only slightly better for the three-month rate, with twenty-four economists above 50%, and one expert actually getting the direction right two-thirds of the time.

For a final test, I examined future predictions of the economists with the most accurate predictions to determine if success could continue for the short term. The three economists in each survey with the closest prediction for the thirty-year bond were examined, although ties cause as many as seven economists to be included in this winner's bracket. Only 44% of these economists (48 of 108) were in the top half of the next survey, suggesting that economists with the closest forecasts cannot repeat their performance.

IMPLICATIONS FOR INVESTORS

The inability of economists to forecast interest rates has important implications for investors. Bond prices depend almost entirely on two factors: default risk and interest rates.[2] To earn above-market returns in the bond market, one needs to be able to predict default risk or interest rates better than the market. Bond rating agencies like Moody's and Standard & Poor's do an outstanding job at predicting default risk. Consequently, it is improbable that fixed-income fund managers can predict default risk better than the market consensus.

The ability to earn above-market returns in bonds then boils down to predicting interest rates correctly, but my analysis of the *Wall Street Journal* survey clearly shows that economists working for top investment banks, commercial banks, money management firms, and investment newsletters have no ability in this department.

If fund managers cannot accurately predict interest rates, actively managed bond funds have no edge over passively managed funds. Once management fees are factored in, the advantage goes to index funds. Indeed, there is overwhelming evidence that the bond market is brutally efficient, and the performance of bond managers reflects this efficiency.

For example, as of June 1, 1996, only 23.4% of taxable bond funds and 33.9% of tax-free bond funds had a one-year record better than the relevant bond index, compared with 44.1% of general equity funds and 58.5% of aggressive growth funds. In a longer-term study, Firman [1994] observes that only 128 of 800 fixed-income pension managers (16%) have a ten-year record better than the relevant bond index.[3]

CONCLUSION

Economists participating in the *Wall Street Journal* forecasting survey have no ability to predict interest rates. Since interest rates cannot be predicted, bond managers have no reliable method with which to earn above-market returns. Instead, actively managed bond funds, shackled by management fees, and with no superior ability to predict interest rates, have generally underperformed the relevant bond index. Bond index funds should appeal to investors for this reason.

ENDNOTES

[1]Six participants in the most recent survey predicted the yield on the thirty-year Treasury bond out to the second decimal point (e.g., 6.79% instead of rounding to 6.8%).

[2]Some bonds are also subject to changes in the tax code, as the inverse relationship between the price of municipal bonds and the popularity of flat tax proposals clearly indicates.

[3]See Blake, Elton, and Gruber [1993] for further evidence. For an overview on the efficiency of capital markets, see Fama [1991].

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Professional Forecasts of Interest Rates and Exchange Rates: Evidence from the Wall Street Journal's Panel of Economists

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Abstract

We use individual economists' 6-month-ahead forecasts of interest rates and exchange rates from the *Wall Street Journal*'s survey to test for forecast unbiasedness, accuracy, and heterogeneity. We find that a majority of economists produced unbiased forecasts but that none predicted directions of changes more accurately than chance. We find that the forecast accuracy of most of the economists is statistically indistinguishable from that of the random walk model when forecasting the Treasury bill rate but that the forecast accuracy is significantly worse for many of the forecasters for predictions of the Treasury bond rate and the exchange rate. Regressions involving deviations in economists' forecasts from forecast averages produced evidence of systematic heterogeneity across economists, including evidence that independent economists make more radical forecasts.

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Professional Forecasts of Interest Rates and Exchange Rates: Evidence from the Wall Street Journal's Panel of Economists

Professional forecasters' predictions of macroeconomic variables are of widespread interest. Governments, businesses, and households purchase forecasts, presumably to help them form their own expectations and aid in economic decision-making.[1] Economic researchers increasingly use surveys of professional forecasters' predictions as proxies of otherwise unobservable expectations in studying asset price determination.[2] But compared with the effort put into making macroeconomic forecasts, the effort put into assessing forecast quality ex post is small (Fildes and Stekler (2002), p 462).

Ex post assessments of forecast quality are potentially valuable to forecasters and users of forecasts alike. The theory of rational expectations implies that, if professional forecasters understand fundamental economic processes, they will produce unbiased, identical forecasts given access to the same information and presented with similar incentives with respect to forecast accuracy. If ex post assessments show forecasters' predictions to be unbiased and statistically identical, they serve to increase confidence in the profession's knowledge of economic processes, researchers' use of forecasts to proxy economic expectations, and agents' use of forecasts to inform economic decision-making. But if assessments yield evidence of bias or heterogeneity, they call for a reexamination of assumptions about information access, incentives and, possibly, understanding of economic processes.

[1] For example, Carroll (2003) reports evidence that households use the reported forecasts of professional economists in forming their own expectations.

[2] For example, Anderson et al (2003) and the references cited by them, discuss researchers' use of professional economists' forecasts of macroeconomic variables to distinguish expected from unexpected macroeconomic announcements in studies of financial market reactions to economic news. Frankel and Froot (1987) and MacDonald (2000) observe that forecasts of interest rates and exchange rates potentially enable researchers to separate the confounding effects of expectations and time-varying risk premiums.

Of the studies that assess forecast quality from survey data, most focus on inflation, GDP and exchange rate forecasts and several cast doubt on the rationality of forecasters (MacDonald (2000)). For example Ito (1990), using survey data of individual economists' exchange rate forecasts, finds evidence of heterogeneous expectations, as do MacDonald and Marsh (1996), who use individual economists' exchange rate forecasts from a different survey. Lamont (2002) finds that the patterns of economists' forecasts of real GDP, the unemployment rate and the inflation rate are inconsistent with the single goal of forecast accuracy, suggesting strategic behavior. Laster *et al.* (1999) also finds evidence of strategic behavior by forecasters making real GDP forecasts from survey data which groups forecasters by industry rather than identifying them individually, which raises the issue of how carefully survey participants make their predictions when they are not identified. Compared with inflation, GDP and exchange rate forecasting, interest rate forecasting has received less attention.

To help address the comparative dearth of forecast assessments and to contribute to the debate on forecaster rationality we analyze interest rate and exchange rate forecasts from a highly visible but relatively little studied survey of forecasters, the *Wall Street Journal's* panel of economists. This survey is particularly well-suited to assessing forecast quality because the names and employers of the forecaster-economists are published along side their forecasts, which should give the economists strong incentives to think carefully about their forecasts. We focus on interest rate and exchange rate forecasts because their actual values are never subject to subsequent revision, unlike, say GDP, so there is no question about the actual values economists were predicting.[3] In addition, the *Wall Street Journal* surveys contain consistent data on interest rate and exchange rate forecasts for a longer period than on other variables. We proceed by testing whether economists' forecasts are unbiased, more accurate than naïve prediction rules,

[3] Keane and Runkle (1990) present evidence that using preliminary versus revised data can change the conclusions from unbiasedness tests.

and heterogeneous or indicative of strategic behavior by economists. We study the forecasts of individual economists as well as the survey means, allowing for the possibility that the interest rates and exchanges rates forecasted are non-stationary. We are unaware of previous papers that allow for non-stationarity in the actual data when applying tests of forecast unbiasedness to individual data. We are also unaware of previous papers using interest rate and exchange rate forecasts from the *Wall Street Journal* survey to study forecast unbiasedness, assess the statistical significance of forecast accuracy, or investigate forecast heterogeneity and possibly strategic behavior by economists.

To preview our results, we find that a majority of economists produce forecasts that are unbiased and that most produce forecasts that are less accurate than the forecasts generated by a random walk model. While efficient financial markets should make accurate forecasting of interest rates or exchange rates impossible, rational forecasters should not do significantly worse than a random walk model. We find that the economists' forecasts exhibit the same kind of heterogeneity found by Ito (1990) and MacDonald and Marsh (1996), using Japanese and European survey data, respectively. When we apply the models of Laster *et al.* (1999) and Lamont (2002) to our economists' forecasts we find evidence of strategic behavior similar to Laster *et al,* but contrary to Lamont's finding that economists make more extreme forecasts as they age, we find that more experienced economists make less radical forecasts.

The rest of the paper is organized as follows. Section 1 briefly reviews some of the past work on evaluating survey measures of expectations. Section 2 describes our data. Section 3 reports our empirical results and section 4 offers some conclusions.

1. Review of Past Work

Although researchers have put less effort towards assessing professional economists' forecasts than seems warranted, the existing research focuses on three issues.[4] The first is whether mean or median responses, usually referred to as consensus forecasts, give misleading inferences about the unbiasedness and rationality of individual forecasters. Figlewski and Wachtel (1981) report that pooling individuals' inflation forecasts from the Livingston survey produces stronger evidence of bias than using survey averages. Keane and Runkle (1990) find that individuals' inflation forecasts from the Survey of Professional Forecasters (SPF) are generally unbiased whereas Bonham and Cohen (2001) find many of the forecasters in the SPF to be biased and systematically heterogeneous so that pooling their forecasts is inappropriate.[5] The finding of bias in inflation expectations runs contrary to rational expectations, and might reflect heterogeneity of expectations. Whether the individual forecasts of interest rates and exchange rates of professional economists are similarly plagued by bias is a question addressed below.

A second issue of research focus is whether the standard tests of economists' forecast unbiasedness are rendered invalid by nonstationarity in the variables economists' forecast.[6] Liu and Maddala (1992) find that exchange rate forecasts from the Money Market Services (MMS) survey appear to be nonstationary but cointegrated with the actual data and thus, potentially unbiased; when they introduce a restricted cointegration test they find that the forecasts are indeed unbiased. In contrast, Aggarwal *et al.* (1995) and Schirm (2003) find that only about half

[4] Much of the work on evaluating survey measures of expectations focuses on inflation forecasts. See Croushore (1998) and Thomas (1999) for reviews of this work. MacDonald (2000) examines previous work on financial market expectations.
[5] Bonham and Cohen (2001) test whether the coefficients of the standard unbiasedness equation are the same across individuals and reject this hypothesis. Batchelor and Dua (1991) use individual forecast data from the Blue Chip Economic Indicators and find that most individuals are unbiased.
[6] The standard test is to regress the actual value being forecasted on the forecast and test that the intercept is zero and the slope is one.

the macroeconomic variables forecasted by economists in the MMS surveys appear unbiased after testing for nonstationarity and cointegration.[7] But Osterberg (2000), applying the Liu-Maddala techniques to more recent exchange rate forecasts in the MMS survey, finds that these forecasts are unbiased. The aforementioned tests, it should be noted, all use the median responses from the MMS surveys rather than forecasts of individual economists. To our knowledge the issue of variable non-stationarity and forecast unbiasedness has not been investigated using forecasts by individual economists.

A third issue of research focus concerns forecast heterogeneity and strategic behavior by forecasters as a potential source of such heterogeneity. Study of this issue has been furthered by the availability of data reporting forecasts by individuals. Ito (1990) and MacDonald and Marsh (1996) use individual data and report evidence supporting systematically heterogeneous expectations about exchange rate movements. The latter paper also finds that variations in the degree of heterogeneity can help explain the volume of trading in financial markets. Scharfstein and Stein (1990) and Erbeck and Waldmann (1996) argue that the incentive structure facing forecasters leads to "herding," that is, making forecasts that are close to the mean or "consensus" forecast. In contrast, Laster *et al.* (1999) and Lamont (2002) suggest that incentives could lead forecasters to make forecasts that are more extreme than their true expectations if forecasters are rewarded not only for being right but for being right when others are wrong. Laster *et al* (1999) find evidence consistent with strategic forecasting using forecasts of real GDP from the Blue Chip Economic Indicators, although their data are not ideal for testing their theory since

[7] These variables include the consumer price index, the producer price index, the M_1 money supply, personal income, durable goods, industrial production, retail sales, the index of leading indicators, housing starts, the trade balance, and unemployment.

individual forecasters are not identified, only the industry of their employment.[8] Lamont (2002) uses *Business Week's* annual set of economists' forecasts for real GDP growth, inflation, and unemployment to test whether forecasters make more radical predictions when they own their own firms, and hence may gain the most from publicity. He finds support for this hypothesis, as well as evidence that forecasters produce forecasts that deviate more from the mean forecast as they age. Perhaps due to the paucity of data on interest rate and exchange rate forecasts by individuals, the issue of heterogeneity in interest rate forecasts and strategic behavior in forecasting interest rates and exchange rates remains largely unstudied.

To investigate the rationality, accuracy, and heterogeneity for individual forecasters' interest rate and exchange rate forecasts we use data from the *Wall Street Journal's* bi-annual survey of economists. Several researchers have used these data previously, mainly to examine forecast accuracy. Kolb and Stekler (1996) examine the six-month-ahead interest rate forecasts from 1982 through January 1990 and find little evidence that forecasters, individually or on average, can predict the sign of interest rate changes. Greer reports similar evidence for predicting the direction of one-year changes for various variables for 1984-1997 (Greer (1999)) and for the long-term interest rate for 1984-1998 (Greer (2003)). Cho (1996) evaluates the six-month-ahead predictions of twenty-four forecasters who participated in all the surveys from December 1989 through June 1994. He finds that about 80 percent of the forecasters predicted the short-term interest rate more accurately than a random walk model but that very few predicted the long-term interest rate or the exchange rate better than a random walk model. Eisenbeis *et al.* (2002) uses the *Wall Street Journal* data from 1986 to 1999 to illustrate a new approach to ranking forecasters across variables that differ in volatility and cross-correlation.

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[8] Pons-Novell (2003), using Livingston survey data on forecasts of the unemployment rate, found support for industry effects as in Laster *et al.* (1999) but not the age effect found by Lamont(2002) . The Livingston data, however, do not identify the individual respondents by name.

But to our knowledge, researchers have not previously used the *Wall Street Journal* data to test for unbiasedness of individual forecasts or to test for strategic forecasting by individual forecasters.

After describing our data, we employ them to investigate the dominating issues in the recent work on expectations of economic variables: unbiasedness of individuals' forecasts, the implications of nonstationarity of the data for the accuracy of unbiasedness tests, and systematic heterogeneity of forecasts, possibly as a result of strategic behavior. In addition, we go beyond past researchers' use of the *Wall Street Journal* data by examining the statistical significance of the surveyed economists' forecast accuracy.

2. The *Wall Street Journal* survey data

Since 1981 the *Wall Street Journal* has published forecasts of several economic variables by a set of economists at the beginning and at the mid-point of each year. The economists are identified both by name and by employer. The survey is dominated by economists employed by banks and securities firms but it also includes representatives from non-financial industries, consulting and forecasting companies, universities and professional associations.[9] The initial survey presented economists' forecasts of the prime rate. In January 1982 the survey introduced forecasts of the Treasury bill and Treasury bond interest rates. Additional forecasts have been added including the CPI inflation rate, real GDP growth, and the dollar-yen exchange rate, among others. In the January survey economists are asked for their forecasts of the Treasury bill rate, Treasury bond rate, and the dollar-yen exchange rates for the last business day of June, and

[9] For respondents that appeared in at least six surveys from January 1982 through July 2002, the employer mix is as follows: banks (30 individuals and 394 observations), econometric modelers (5 and 108), independent forecasters (26 and 325), industrial corporations (5 and 41), securities firms (39 and 626), and others (10 and 154).

in the July survey they are asked for their forecasts for the last business day of December.[10] The surveys are published in the first week of January and July, along with commentary on the forecasts and, more recently, discussion of the accuracy of the last set of forecasts.[11]

In this paper we examine the six-month-ahead forecasts of the Treasury bill and Treasury bond rates that began in 1982 along with the six-month-ahead forecasts of the dollar-yen exchange rate that began in 1989. Our sample ends with the July 2002 survey. This long time period allows larger sample sizes for individual forecasters and a larger number of participants. We choose the interest rate and exchange rate variables both because they appear on the largest number of surveys and because the actual data are not revised so there is no question of what variable the forecasters were predicting.[12]

Table 1 reports the means and standard deviations of the survey responses along with the range, and number of respondents. The number of respondents varies over time: only twelve economists participated in the January 1982 survey compared with fifty-five in the July 2002 survey. There is also considerable turnover in the respondents themselves. Table 1 also reports the actual values for the Treasury bill rate, the Treasury bond rate, and the yen-dollar exchange rate on the last business day of June and December.

For several tests we restrict the sample to the set of respondents that made at least twenty forecasts. Table 2 reports the names, participation dates, and professional affiliations of these respondents from 1982 through 2002.

[10] Respondents have often been asked for 12-month ahead forecasts but these are not available for the entire period.
[11] The selection of survey respondents does not depend on their past performance. The *Journal* tries to get broad representation but also wants to include the chief economists from major financial institutions. We thank Jon Hilsenrath of the *Wall Street Journal* for this information.

[12] There was a change in the definition of the three-month Treasury bill rate from the discount yield to the bond-equivalent yield starting with the July 1989 survey. The long-term bond rate refers to the thirty-year bond until the July 2001 survey when it was changed to the ten-year rate. All data are available from the authors on request.

Figures 1-3 show the dispersion in the forecast errors, defined as actual minus predicted, of the Treasury bill rate, the Treasury bond rate, and the yen-dollar exchange rate. The figures are similar in showing a considerable spread in forecasts. The assumption that agents form unique rational expectations using the same model and same information is clearly not supported by the data. Figure 1 indicates that the errors in predicting the Treasury bill rate are largely of one sign for about half the surveys, suggesting that while expectations vary across individuals a common source exists for at least some of the error. Figures 2 and 3 provide stronger support for this interpretation, where an even higher proportion of the survey errors are of the same sign for the long-term bond rate and the exchange rate. The correlation coefficient for the two interest rate forecast errors is .66, indicating that most of the forecast errors are from unpredicted shifts in the yield curve rather than unpredicted changes in its slope. There is little evidence of correlation in the errors for interest rates and the exchange rate.[13]

3. Evaluating the survey data

3.1. Tests of unbiasedness

A major issue in the literature on economic expectations is unbiasedness, which is a requirement for rationality when a forecaster's loss function is symmetric about the forecast error. Denoting the forecast of a variable made at time (t-1) for time t as ${}_{t-1}F_t$ and the actual value of the variable as A_t, the usual test involves estimating

$$A_t = \alpha + \beta \; {}_{t-1}F_t + \varepsilon_t \qquad [1]$$

[13] For the forecast errors in the figures, the correlation between the Treasury bill forecast errors and the exchange rate errors is .02 and the correlation between the Treasury bond forecast errors and the exchange rate errors is –.07.

where ε_t is a random error term. A forecast series is unbiased if the joint hypothesis that α=0 and β=1 cannot be rejected.[14]

As is well-known estimating [1] may produce misleading inferences when A and F are nonstationary and not cointegrated since the error term will also be nonstationary, resulting in the spurious regression problem noted by Granger and Newbold (1974). If the actual series is nonstationary, an unbiased forecast must also be nonstationary and the two series must be cointegrated with a cointegrating vector of zero and one. Liu and Maddala (1992) suggest a restricted cointegration test when A and F are I(1): impose the restrictions α=0 and β=1 and use the data to compute forecast errors; if the forecast errors are stationary, the restrictions are supported and the forecasts are unbiased since the cointegrating vector is unique with only two series.[15] We perform the Liu-Maddala test below after first establishing whether A and F are I(1).

To establish that the As – the daily Treasury bill, Treasury bond and exchange rate data sampled at six-month intervals, the data frequency that matches our forecast series -- are I(1), we perform unit root tests. Using levels data we cannot reject the hypothesis of a unit root for any of the three series, but using first-differenced data we can reject the unit root hypothesis for all three. Thus all three actual series appear to be I(1).[16]

To establish that the Fs -- the Treasury bill, Treasury bond and yen-dollar exchange rate forecast series of the thirty-three economists listed in Table 2 who responded to at least 20 surveys -- are I(1), we perform 99 unit root tests (three forecast series for each of the thirty-three

[14] Rationality tests often include a test that ε_t is not autocorrelated and may also include other information available at time (t-1) on the right hand side of equation [1]. Rationality requires that all such variables have zero coefficients.
[15] Papers employing this restricted cointegration test include Hakkio and Rush (1989) and Osterberg (2000).

[16] The ADF statistics using 1 lag for the levels of the Treasury Bill rate, Treasury bond rate, and yen-dollar exchange rate are -.867, -.970, and -2.396 respectively, indicating that each series has at least one unit root. The ADF statistics for the first differences are -4.950, -6.143, and -3.612 indicating that all series are I(1). Rose (1988) and Rapach and Weber (2004) also find that the nominal interest rate has a unit root while Baillie and Bollerslev (1989) report similar findings for nominal exchange rates.

economists). The t statistics for augmented Dickey-Fuller (ADF) unit root tests performed on levels and first differences for individual forecasters are reported in the second column of Tables 3-5. Starred values indicate rejection of the unit root hypothesis at the 0.01, 0.05 or 0.10 levels of significance. Of the 99 forecast series, 71 appear to be I(1) using the 10% significance level or better.

To complete the Liu-Maddala test we impose the restriction that $\alpha=0$ and $\beta=1$ on [1], use the As and Fs to compute the forecast errors, and perform ADF tests to determine whether the forecast errors are I(0). The third columns in Tables 3-5 report ADF t statistics for the case of a zero intercept since the null hypothesis is that the residuals have an expected value of zero. Box-Ljung Q statistics to test for serial correlation in the residuals appear beneath the t statistics. Of the 99 forecast error series all but four are I(0) at the 10% level or better and only four show evidence of serially correlated errors.

To pass the Liu-Maddala test the Fs must be I(1) and the forecast residuals must be I(0). Nearly 60 % of the Treasury bill rate forecasts reported in Table 3 meet both criteria.[17] In addition, over three-quarters of the Treasury bond rate forecast series in Table 4 and two-thirds of the exchange rate forecast series in Table 5 meet both criteria.[18] Altogether, two-thirds (67) of the 99 forecast series pass the Liu-Maddala test of unbiasedness. Moreover, the three series of mean survey responses pass the Liu-Maddala test, as indicated in the last row of each table.

While the results of the Liu-Maddala tests are encouraging to proponents of forecaster rationality, Lopes (2000) provides evidence that the power of their restricted cointegration test

[17] About one-third of the forecast series appear to be I(0) despite the Treasury bill rate series being I(1). First differences of four other forecast series appear to be nonstationary even though the first difference of the Treasury bill rate series is stationary; the forecast errors in these four cases do appear stationary, however. For some individuals there are gaps, usually just one, in the forecast series. While Shin and Sarker (1993) find that occasional missing values do not change the asymptotic distribution of the standard Dickey-Fuller tests, our samples are small so that the results with a gap remain suspect.

[18] Of the eleven exchange rate forecast series that failed, three had ten or fewer observations.

may be low, as is usual with unit root tests. He uses Monte Carlo techniques to show that a more powerful test of unbiasedness in finite samples is a simple t-test for the hypothesis that a forecast series' mean forecast error is zero. Accordingly, we also report the mean forecast error and its t-statistic in column 4 of each table. We fail to reject at the 10% level the null hypothesis of unbiasedness for 73% of the Treasury bill forecast series, 67% of the Treasury bond forecast series, and 88% of the exchange rate forecast series.[19] Of the forecast series with test statistics that reject the null, all of the Treasury bill rate and exchange rate forecast series and about two-thirds of the Treasury bond rate forecast series err on the high side. Biased forecasts by some forecasters did not serve to impart bias to the survey mean forecasts, however: the average forecast errors of the survey mean forecasts were statistically indistinguishable from zero, implying unbiasedness.

In summary, about two-thirds of the forecast series appear to be statistically unbiased, as do all three series of mean survey responses. Economists whose forecasts appeared to be biased usually overestimated the 6-month-ahead level of the Treasury bill, Treasury bond or yen-dollar exchange rate, with overestimation occurring more frequently in predicting interest rates than exchange rates. Based on the t-tests for unbiasedness at the 10% level, about 60 % of the survey economists were statistically unbiased in their predictions of the Treasury bill, Treasury bonds and exchange rate; about 10% made biased forecasts of one of the three rates; and the remaining 30% made biased forecasts of two series. No economist made biased predictions of all three rates.[20]

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[19] At the less stringent 5% level, 80%, 73% and 91%, respectively, of the Treasury bill, Treasury bond, and exchange rate series fail to reject the null of unbiasedness.

[20] If the less stringent 5% level is used to judge unbiasedness, 67% of the survey forecasters were statistically unbiased in their predictions of all three rates; about 6% made biased forecasts of one of the rates; and the remaining 27% made biased forecasts of two rates.

3.2 Measures of predictive ability

While unbiasedness is a requirement for rationality of forecasters with symmetric loss functions, predictive ability is a hallmark of forecasters who "know the true model" determining macroeconomic variables. We take two approaches to measuring predictive accuracy: first, we assess forecasters' success at predicting the direction of interest rate and exchange rate changes;[21] second, we compare forecasters' accuracy to the accuracy of a traditional benchmark, the random walk model without drift, and test whether the accuracy metrics are statistically different. Although previous researchers have employed the *Wall Street Journal* survey to assess predictive accuracy using one approach or the other (but not both), they reach contradictory conclusions.[22] Moreover, we are unaware of any previously published research using the *Wall Street Journal* survey that tests for statistical differences in the accuracy of individual economists' forecasts versus forecasts of the random walk model.

In our first approach to predictive accuracy we use standard techniques to assess economists' accuracy in predicting the direction of change in the Treasury bill rate, Treasury bond rate, and yen-dollar exchange rate over 6-month intervals. The results appear in columns five and six of Tables 3-5. Column 5 reports the fraction of correctly-predicted changes along with the p-value for Fisher's exact test of the hypothesis that predicted and actual changes were independent. Column 6 reports the standard χ^2 statistic and the Pesaran-Timmerman (1992) test

[21] Leitch and Tanner (1991) argue that the direction of change is more closely related to profits than say the mean square error for interest rate predictions.
[22] Kolb and Stekler (1996) and Greer (1999, 2003) present tests of directional change whereas Cho (1996) compares economists' forecast errors against the forecast errors made by the naïve model of no change. Kolb and Stekler and Greer find that little evidence that economists can predict the direction of change, whereas Cho finds that eighty percent of the economists outperformed the naive model when forecasting the Treasury bill rate.

statistic, also with a χ^2 distribution with 1 degree of freedom, of the same independence hypothesis.[23]

The directional accuracy tests suggest that the surveyed economists provide no useful information.[24] In forecasting the Treasury bill rate about two-thirds of economists predicted the direction of change correctly more than half the time, but for no economist was the percentage of correctly predicted directions significantly greater than expected by chance; moreover for a few, the percentage was significantly lower. In predicting the Treasury bond rate, only about one-third of economists forecasted directional change correctly more than half the time; nevertheless, few predicted directional change less accurately than chance. The surveyed economists were more successful in predicting directional change in the yen-dollar exchange rate: about 80 predicted correctly more than half the time; nevertheless none predicted correctly more often than would be expected by chance. Finally, the survey means successfully predicted the direction of Treasury bill rate and exchange-rate changes about as accurately as chance, but predicted the direction of Treasury bond rate changes significantly more poorly than chance. Thus, when set the task of predicting the direction of interest rate and exchange rate changes, the surveyed economists acquit themselves modestly, at best.

In our second approach to predictive accuracy, we compare the accuracy of the surveyed economists' predictions to the accuracy of a model predicting that interest rates and exchange rates follow a random walk without drift. Specifically, we computed the ratio of the mean square errors (MSEs) of each economist's forecast series to the MSEs of forecast series covering the

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[23] For each forecaster we constructed a contingency table with the number of times the forecaster predicted a decline and there was a decline, the number of times the forecaster predicted an increase and there was an increase, the number of times the forecaster incorrectly predicted a decrease, and the number of times the forecaster incorrectly predicted an increase.

[24] We also performed the test of Cumby and Modest (1987), suggested by Stekler and Petrei (2003), in which the actual change is regressed on a binary variable taking the value of one if the forecaster predicted an increase and zero otherwise. These tests, not reported, also indicated that the respondents were unable to provide useful information on the direction of change.

same dates but using as forecasts the six-month-earlier actual values (that is, actuals on the last business day in December and June, respectively, to forecast values for the last business day in June and December, respectively; these actuals are usually published along side the forecasts in the *Wall Street Journal)*. The question becomes whether individual economists can outperform the random walk model by achieving a ratio less than one. In addition to analyzing this ratio we follow the recommendation of Fildes and Stekler (2002) and test for statistically significant differences between individuals' forecasts and random walk forecasts of no change using the modified Diebold-Mariano (1995) test statistic proposed by Harvey *et al.* (1997). Specifically, this statistic tests whether the mean difference between the squared forecast errors of the economist and of the random walk model is significantly different from zero; this statistic has a t-distribution under the null hypothesis that the mean is zero. We report our results in Tables 3-5. The next-to-the last column reports the number of forecasts made by each economist together with the sum of the squared forecast errors. The last column reports the ratio of each economist's MSE to the MSE from a random walk model and the Diebold-Marino statistic in parentheses.

The statistical evidence indicates that economists generally fail to beat and tend to be statistically less accurate than the random walk model. Although in predicting the Treasury bill rate eight of thirty-three economists achieve a MSE ratio less than one, the Diebold-Marino statistics indicate that no economist forecasts significantly better than the random walk model (i.e. a t-statistic that is significantly less than zero) and five do significantly worse at the 10% level. In predicting the Treasury bond rate, no economist achieved a MSE ratio less than one; moreover, about two-thirds of economists predicted significantly worse than a random walk model, judging by the Diebold-Marino statistics (i.e., a t-statistic significantly greater than zero). Accuracy in predicting the yen-dollar exchange was little better: no economist achieved a MSE ratio less than one, and half predicted significantly worse than a random walk model, judged by the Diebold-Marino statistics. Economists' poor predictive ability is reflected in the survey mean predictions. Although survey mean predictions of the Treasury bill rate achieve a MSE ratio less than one, the survey mean predictions do not differ statistically from the random walk predictions. Survey mean predictions of neither the Treasury bond rate nor the yen-dollar exchange rate achieved MSE ratios less than one, and although the mean predictions of the Treasury bond rate did not differ statistically from the random walk predictions, the mean exchange-rate predictions were significantly worse than the random walk predictions.

Taken all together, the evidence on predictive ability suggests that agents who use forecasts and prize accuracy would have suffered less disappointment by assuming that interest rates and exchange rates stay at their last observed levels rather than by relying on forecasts from the *Wall Street Journal* survey. The dismal predictive accuracy of many of the economists leads us to ask whether the forecasts are systematically heterogeneous, possibly because some economists face incentives to forecast large interest rate and exchange rate changes.

3.3. Tests of systematic heterogeneity of forecasts

Professional economists who are rational, who know the "true model," and who, in addition, have access to the same macroeconomic information relevant to forecasting interest rates and exchange rates – as a priori reasoning suggests is probably the case – should produce homogenous (identical) forecasts. In this section we examine whether forecasts of the economists in the *Wall Street Journal* survey are homogeneous or systematically heterogeneous.

To test for homogeneity in forecasts we follow Ito (1990), who posits a fixed-effects model. Ito models the forecast for time t of the j^{th} economist, $f_{j,t}$, as being a function of common information, I_t, an individual effect represented by an individual-specific dummy variable, g_j, and a random error term, $u_{j,t}$:

$$f_{j,t} = f(I_t) + g_j + u_{j,t} . \qquad [2]$$

Ito assumes further that $f(I_t)$ contains a constant so that the average of the g_js may be set to zero. Averaging equation [2] across all economists and then subtracting the average from [2] yields:

$$f_{j,t} - f_{AVE,t} = g_j + (u_{j,t} - u_{AVE,t}) . \qquad [3]$$

Homogeneity of forecasts can be tested by estimating [3] on forecast data for individual economists and testing that the estimated values of g_j are identical across economists.[25] [26]

Table 6 presents the results from estimating [3] using the Treasury bill rate, Treasury bond rate and the yen-dollar exchange rate forecasts of the economists in the *Wall Street Journal* survey and testing for forecast homogeneity. Like Ito (1990) we estimate [3] twice, first letting the g_js represent dummy variables for individual economists and again letting the g_js represent dummy variables for the economists' sector of employment. Panels A and B, respectively, report results from the two estimations. We report results for two sub-samples of economists, one including all economists having at least six survey responses (Panel 1) and another including all economists having at least twenty responses (Panel 2), the same economists whose forecasts were examined in sections 3.1 and 3.2.[27]

The evidence in Table 6 overwhelmingly rejects the hypothesis of homogeneous forecasts. In Panel A, F tests reject the null hypothesis of identical g_j estimates for all economists at the 0.01 level for all the data sets, indicating the presence of significant individual effects. In

[25] An essentially identical approach is to regress the individual forecasts on a set of time dummies as well as a set of individual dummies and test for individual effects.

[26] Ito uses [3] to test for heterogeneity in exchange rate forecasts made by Japanese economists. He finds that the data reject the hypothesis of homogeneous forecasts both when the g_js are individual dummy variables and when the g_js represent the industry of the economist's employment. Ito also finds that economists employed in export industries have a depreciation bias whereas those employed in the import business have an appreciation bias, a pattern he terms the "wishful thinking" effect. MacDonald and Marsh (1996) also find evidence of heterogeneity across exchange rate forecasters from a large survey of European economists. In addition they report that the dispersion of forecasts is positively related to the volume of foreign exchange trading. MacDonald and Marsh report that the European economists are generally less accurate than a random walk for 3-month predictions but that a substantial number of economists beat a random walk when making 12-month forecasts.

[27] These are unbalanced panels since participants change over time.

Panel B, coefficient estimates of five employment sectors appear (top number, standard errors beneath) along with F tests of the null hypothesis that the estimated coefficients are identical (reported in the last row). The data soundly reject the null for all data sets. The coefficient estimates indicate that, compared with other economists, independent forecasters made significantly lower forecasts of the Treasury bill and Treasury bond rate and significantly higher forecasts of the yen-dollar exchange rate. Economists employed by securities firms also made comparatively low forecasts of the Treasury bond rate, but not as low as economists employed by independent firms. Economists affiliated with banks produced forecasts statistically indistinguishable from the consensus, as did economists employed by econometric modeling firms, except for yen-dollar exchange rate forecasts made by Panel 2, which were statistically lower.

In summary, the evidence from the *Wall Street Journal* survey suggests that the economists' forecasts are indeed systematically heterogeneous. This finding leads us to investigate whether individual forecasters behave strategically in making their forecasts.

3.4. Tests of strategic forecasting

Laster *et al.* (1999) and Lamont (2002) suggest that the incentive structure facing professional economists potentially motivates them to supply heterogeneous forecasts. Specifically, they argue that if economists are rewarded both for forecast accuracy and for "standing out from the crowd," economists may announce more extreme predictions than if they were rewarded for forecast accuracy alone.[28] To investigate this possibility we estimate a model combining elements of Lamont (2002) and Laster *et al.* (1999):

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[28] Lamont (2002) models forecasters' payoff function as follows:

$$w_j = R(|f_j - a|, |f_j - f_{c(-j)}|)$$

$$|f_j - f_{c(-j)}|_t = \beta_0 + \beta_1\, AGE_{j,t} + \beta_2\, AGE_{j,t} * MODEL_{j,t} + \beta_3\, AVEDEV(-j)_t$$

$$+ \beta_4\, OWN_{j,t} + \sum \gamma_i\, D_{i,t} + \varepsilon_{j,t} \qquad [4]$$

Following Lamont our dependent variable – a measure of "standing out from the crowd" – is the absolute value of the difference between an individual economist's time t forecast and the average time t forecast omitting that economist's forecast. AGE is the number of years an economist had participated in the *Wall Street Journal* survey at the time of survey t while the interaction term AGE*MODEL allows the effect of an economist's age to differ if the economist is employed by an econometric modeling firm.[29] AGE is included to control for changing incentive structures: incentives might encourage young forecasters to make extreme forecasts so as to gain publicity while encouraging older forecasters to make less extreme forecasts so as to protect the reputations; alternatively, incentives might encourage young forecasters to make less extreme forecasts so as to hide their inexperience while encouraging seasoned, secure forecasters to make more radical forecasts. AVEDEV(-j) is the average absolute deviation of the forecasts from the mean, omitting the j^{th} economist; this latter variable controls for variations in the spread of the forecasts over time. The dummy variable, OWN, equals one if an economist is employed at a firm that bears his name. Finally, following Laster *et al.*, we add dummy variables for the industry employing the j^{th} economist at the time of survey t, the D_{jt}s. Our industries include banks, securities firms, finance departments of corporations, econometric modelers, and economists employed by independent firms not bearing the economists' names, similar to Laster

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where w_j is the payoff to forecaster the j^{th} forecaster, $|f_j - a|$ is the absolute value of the j^{th} forecaster's forecast from the actual value, and $|f_j - f_{c(-j)}|$ is the absolute value of the j^{th} forecaster's forecast from the consensus forecast, omitting the j^{th} forecaster's forecast. Lamont assumes the partial derivative of R with respect to the first argument, R_1, is negative: inaccurate forecasts reduce a forecaster's payoff. But he allows that the partial derivative of R with respect to the second argument, R_2, is an empirical question.

[29] Lamont found that this variable was important and that the effect of age was not significant for forecasts from econometric models.

et al. The hypothesis that economists behave strategically is supported by statistically significant coefficients on AGE, AGE*MODEL, OWN, and the D_{jt}s, as well as by statistical differences among the estimated coefficients of the D_{jt}s.

Table 7 presents estimates of [4] using the Treasury bill rate, Treasury bond rate and the yen-dollar exchange rate forecasts of the economists in the *Wall Street Journal* survey. As in the previous section we report estimates for two sub-samples of economists, one including all economists having at least six survey responses (Panel 1) and another including all economists having at least twenty responses (Panel 2), the same economists whose forecasts were examined in sections 3.1 and 3.2.

The Table 7 estimates show overwhelming evidence of strategic behavior by economists in the form of statistically significant estimated coefficients of AGE, OWN and several of the D_{jt}s, as well as statistical differences among the D_{jt}s. The estimated coefficients of AGE are negative and usually statistically significant, implying that economists make less extreme forecasts the longer they are surveyed.[30] This age effect holds for all economists including those employed by econometric modeling firms, since the estimated coefficient of AGE*MODEL never achieves significance. Though pervasive, the estimated age effects are small in absolute terms: compared with a first-time respondent, an economist in the survey for 10 years (20 surveys) is about 4 basis points closer to the mean interest rate forecast and a little less than one yen closer to the mean exchange rate forecast. Larger in absolute terms is the effect of employment by a forecasting firm bearing one's name: forecasts of such economists deviate more from the mean forecasts than forecasts of other economists by amounts ranging from 13 to

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[30] As noted above, the *Wall Street Journal* does not systematically drop forecasters with poor records so a negative coefficient should not be due to a survivorship bias. It is possible, however, that people who make extreme and inaccurate forecasts drop out to avoid negative publicity. We also estimated a model with age and AVEDEV(-j) as explanatory variables for each of the individuals listed in Table 2. Age was statistically significant at the .10 level for only about one-third of the panel and was negative in most cases. No individual had significantly positive coefficients on age for all three variables being forecasted.

22 basis points for the interest rates and 1.7 yen, on average, for the exchange rate. The name effect appears to drive economists' strategic behavior rather than independence per se: only in forecasting the Treasury bond rate did economists employed by independent firms named for others make forecasts statistically more extreme than the consensus, and even then the effect was absolutely small. Surveyed economists employed by banks appeared to make less extreme forecasts than other economists, judging from the consistently negative and statistically significant estimated coefficients of Banks. Economists employed by securities firms, corporations and econometric modeling firms also tended to make less extreme forecasts, judging from the generally negative although inconsistently significant estimated coefficients of their respective dummy variables. When the hypothesis that economists' forecasts deviated equally from the consensus regardless of employment is tested, F statistics soundly and universally reject the hypothesis. Because it seems unlikely that economists in different industries had differential access to the macroeconomic data needed to make interest rate and exchange rate forecasts, we conclude that incentive structures encourage economists employed in different industries to supply heterogeneous forecasts, with economists from firms bearing their own names being more likely to make extreme forecasts because they gain the most from being right when others are wrong.[31]

3.5 Discussion of results

We believe that the results presented in sections 3.1 – 3.4 present a consistent story. Our findings from section 3.1 – that 30% of economists produced biased forecasts, generally in the upward direction – and from section 3.2 – that economists generally failed to forecast as

[31] We also estimated equation [4] allowing for individual fixed effects or individual random effects. These models gave similar estimates for the effects of AGE and AVEDEV but wiped out the statistical significance of the industry effects. Since individuals change industries occasionally in our sample, as indicated in Table 2, the industry differences appear to be captured by the individual effects.

accurately as the random walk model and sometime forecasted less accurately – is consistent with the heterogeneity of forecasts we found in section 3.3. When we tested for evidence of strategic behavior by economists in section 3.4 by using a synthesis of the Lamont (2002) and Laster *et al.* (1999), we obtained some results similar to theirs. Like Lamont and Laster *et al.* we found that economists from independent firms tend to make more extreme forecasts and, like Lamont, we found that economists whose firms bear their names make forecasts that consistently deviate more from the survey mean than other economists. But whereas Lamont found evidence that economists make more extreme forecasts the longer they are surveyed, we found the opposite to be true: the estimated coefficients of AGE are consistently negative and usually statistically significant.

Although our results on strategic behavior bear some similarities to Lamont and Laster *et al.*'s, we believe it is important to note the advantages of the *Wall Street Journal* survey data on interest rates and exchange rates for testing strategic behavior compared with *Business Week* survey data used by Lamont and the Blue Chip Economic Indicators data used by Laster *et al.* Although the *Business Week* survey publishes forecasts of economists by name, Lamont studied economists' forecasts of real GDP growth, inflation and unemployment, all of which are subject to revision, which raises the issue of which values economists were forecasting. Laster *et al.* also study economists' forecasts of real GDP growth, so the caveats that apply to Lamont apply to Laster *et al.* as well. In addition, the Blue Chip Indicators data Laster *et al.* use groups forecasters by industry rather than identifying them individually; hence the incentives to forecast strategically are not as strong.

Our finding that the *Wall Street Journal's* panel of economists cannot predict changes in interest rates and exchange rates more accurately than a random walk model is not surprising, given the efficiency of financial markets. What is perhaps surprising is that so many of the panel forecast significantly worse than the random walk model. The explanation of these results we favor is that many of the economists face incentives that reward the exceptionally right guess but do not equally penalize the exceptionally wrong guess. An alternative explanation is that even if the economists know the random walk model to be more accurate over time, this leaves them with no story to spin about their forecasts. Always telling customers that you predict no change in interest rates or exchange rates may simply be too truthful to keep one employed.

4. Conclusions

While widespread public interest in forecasts of macroeconomic variables has led professional economists to put considerable effort in generating forecasts, less effort has gone into assessing the quality of these forecasts. The theory of rational expectations implies that professional economists' forecasts should be unbiased and identical given access to the same information and similar incentives with respect to predictive accuracy. Previous studies employing survey data of professional economists' forecasts to assess forecast quality have tended to lack comprehensiveness, suffer from data problems, or produce inconclusive results.

This paper has sought to help fill the void by using semi-annual survey data from the *Wall Street Journal*'s panel of economists to study interest rate and exchange rate forecasts of individual economists. We found that while about 60% of the surveyed economists produced unbiased estimates, virtually all failed to make 6-month ahead forecasts of the Treasury bill rate, Treasury bond rate and yen-dollar exchange rate that beat a naïve random walk model for accuracy, and many made forecasts significantly less accurate than the random walk model. When we tested for homogeneity of interest rate and exchange rate forecasts, we found them to be systematic heterogeneous. In particular, we found that independent economic forecasters (those not employed by banks, security firms, corporations' finance departments, or econometric model firms) made significantly lower forecasts of the Treasury bill rate and Treasury bond rate and significantly higher forecasts of the yen-dollar exchange rate. Evidence of systematically heterogeneous forecasts led us to consider whether economists faced economic incentives to produce heterogeneous forecasts. When we estimated an incentives model combining elements of models estimated by Lamont (2002) and Laster *et al.* (1999), we found evidence that economists who would be expected to gain the most from favorable publicity – those employed by firms named for them – make more extreme forecasts, whereas economists employed by other institutions tend to make more conservative, less extreme forecasts. We found no evidence that economists become more radical with age. If anything, experienced economists appear to preserve their reputations by deviating less from the consensus forecast than inexperienced economists.

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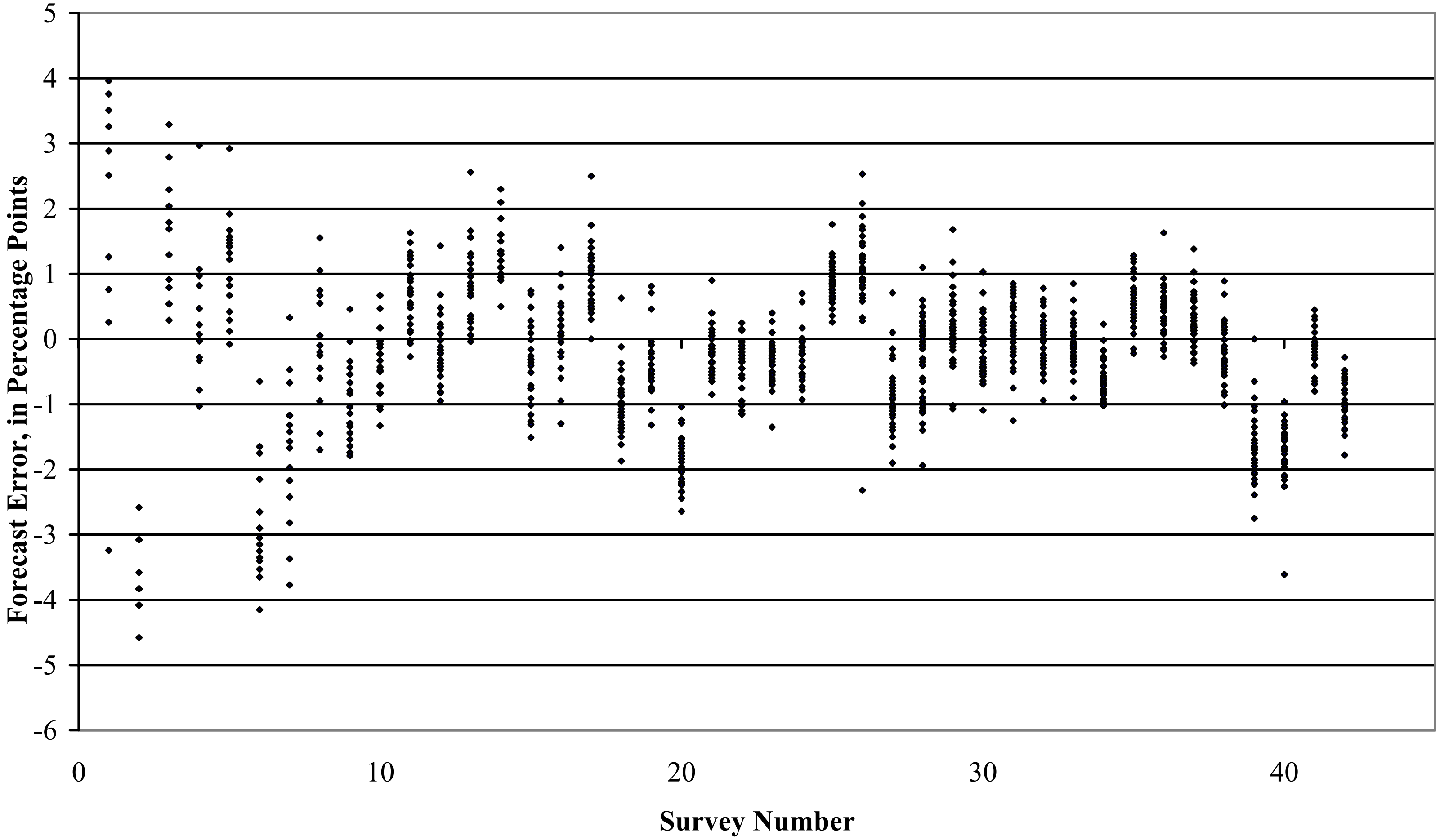
Figure 1

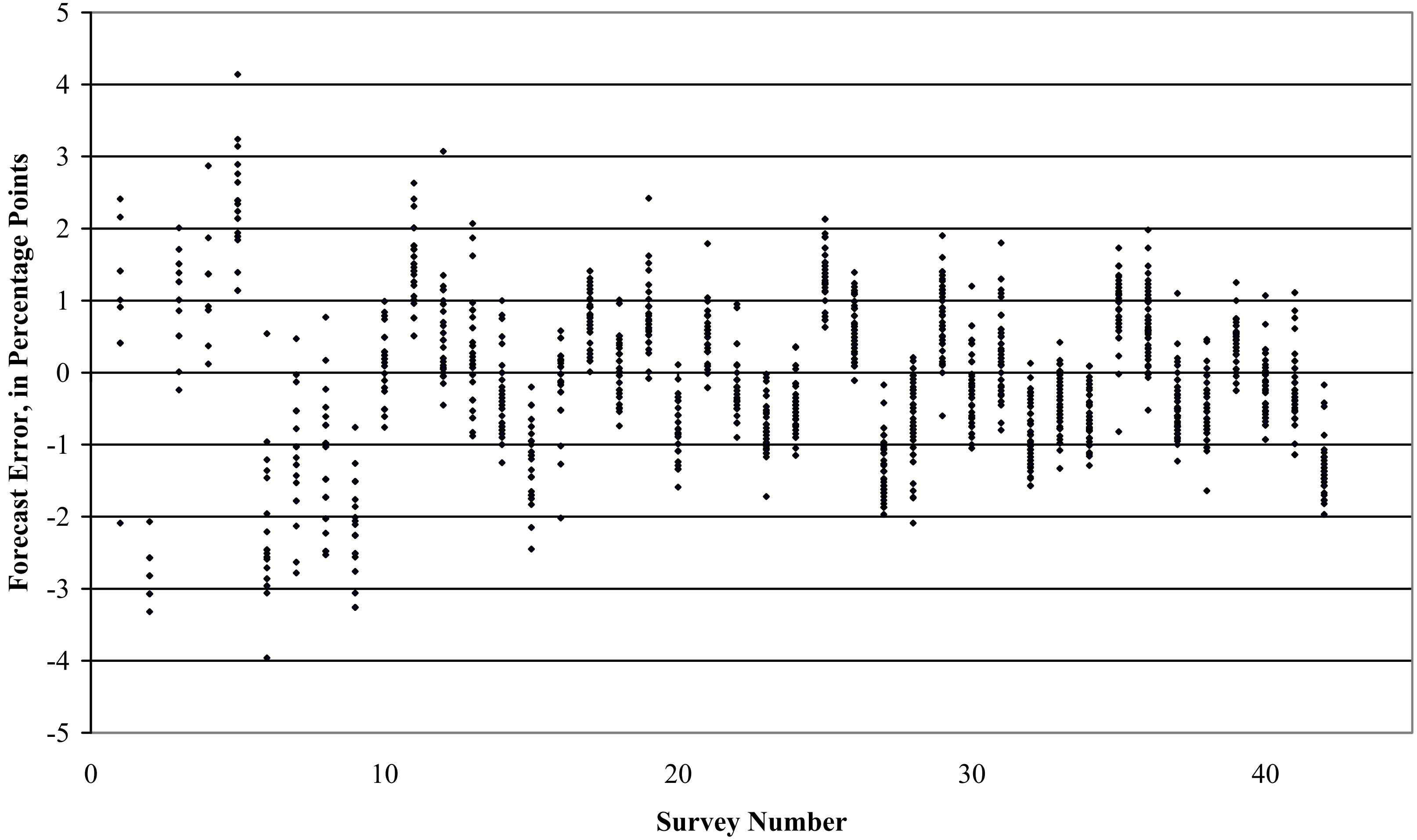
Forecast Errors of the Treasury Bill Rate



Note: Forecast errors are measured as the actual rate minus forecasters' predictions on the survey date, six months earlier. Forecast errors are shown for the 42 surveys beginning with January 1982 and ending with July 2002.

Figure 2

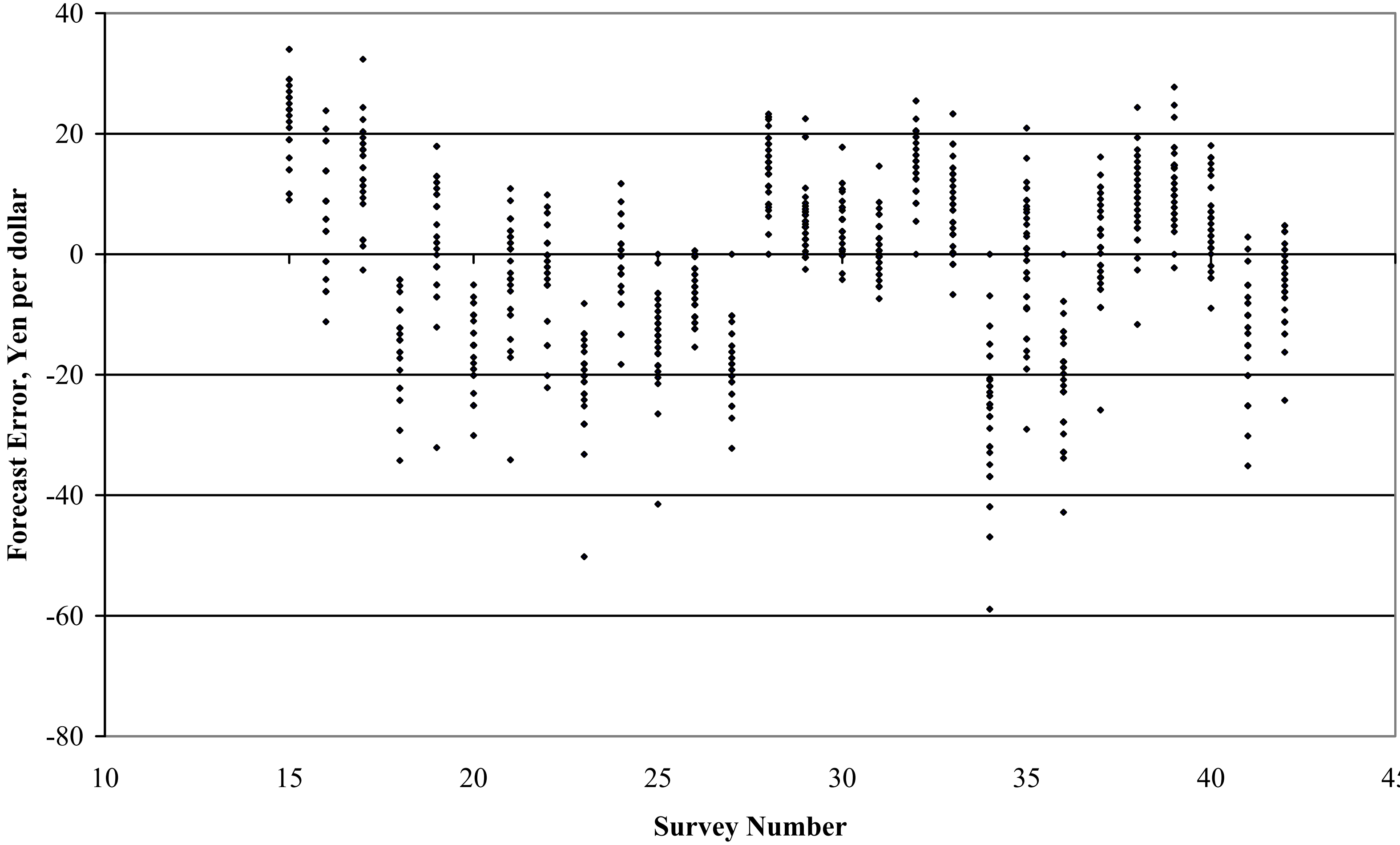
Forecast Errors for theTreasury Bond Rate



See notes to Figure 1.

Figure 3

Forecast Errors for the Yen-Dollar Exchange Rate



Note: Forecasts of the yen-dollar exchange rate were added to the *Wall Street Journal* survey in January 1989. Forecast errors are shown for the 28 surveys from January 1989 to July 2002, which correspond to survey numbers 15-24 in our sample.

Table 1
Summary Statistics for Survey Forecasts

Survey Date	Treasury bill Rate			Treasury bond Rate			Yen-Dollar Rate		
year_mo	Mean S.D.	Range N	Actual	Mean S.D.	Range N	Actual	Mean S.D.	Range N	Actual
1982_01	11.06 2.05	8.8-16 12	12.76	13.05 1.13	11.5-16 12	13.91			
1982_07	11.61 .54	10.5-12.5 14	7.92	13.27 .35	12.5-13.75 14	10.43			
1983_01	7.37 .94	5.5-9.625 17	8.79	10.11 .71	9-11.625 17	11.01			
1983_07	8.60 .89	6-10 17	8.97	10.59 .60	9-11.75 17	11.87			
1984_01	8.72 .64	7-10 24	9.92	11.39 .68	9.5-12.5	13.64			
1984_07	10.62 .76	8.5-12 24	7.85	13.75 .85	11-14.75 24	11.54			
1985_01	8.56 .98	6.5-10.6 24	6.83	11.60 .80	10-13.25 24	10.47			
1985_07	7.31 .82	5.5-8.75 25	7.05	10.51 .83	8.5-11.8 25	9.27			
1986_01	6.96 .58	5.5-7.75 25	5.96	9.45 .63	8-10.5 25	7.24			
1986_07	6.02 .51	5-7 30	5.67	7.41 .51	6.5-8.25 30	7.49			
1987_01	4.98 .48	4.1- 6 35	5.73	7.05 .53	5.88-8 35	8.51			
1987_07	5.91 .50	4.25-6.63 35	5.68	8.45 .66	5.88-9.4 35	8.95			
1988_01	5.70 .58	4-6.6 36	6.56	8.65 .71	6.8-9.75 36	8.87			
1988_07	6.78 .39	5.8-7.6 32	8.1	9.36 .56	8-10.25 32	9			
1989_01	8.29 .60	7.25-9.5 38	7.99	9.25 .49	8.25-10.5 38	8.05	121.37 6.15	110-135 38	144
1989_07	7.76 .52	6.4-9.1 38	7.8	8.12 .48	7.4-10 38	7.98	136.53 8.47	120-135 38	143.8
1990_01	7.03 .48	5.5-8 40	8	7.62 .35	7-8.4 40	8.41	137.78 6.81	120-155 40	152.35
1990_07	7.56 .43	6-8.5 40	6.63	8.16 .40	7.25-9 40	8.26	149.78 7.14	140-170 40	135.75
1991_01	6.14 .42	4.9-7.03 40	5.71	7.65 .46	6-8.5 40	8.42	133.65 9.69	120-170 40	137.9
1991_07	5.84 .35	5-6.6 40	3.96	8.22 .38	7.3-9 40	7.41	140.78 5.61	130-155 40	124.9
1992_01	3.80 .34	2.75-4.5 42	3.65	7.30 .37	6-8 42	7.79	127.64 8.07	115-160 42	125.87
1992_07	3.54 .39	2.9-4.3 42	3.15	7.61 .38	6.45-8.3 42	7.4	127.33 7.07	115-147 42	124.85
1993_01	3.41 .32	2.7-4.45 44	3.1	7.44 .33	6.7-8.4 44	6.68	127.70 7.07	115-157 44	106.8

Table 1, continued

Survey Date	Treasury bill Rate			Treasury bond Rate			Yen-Dollar Rate		
year_mo	Mean S.D.	Range N	Actual	Mean S.D.	Range N	Actual	Mean S.D.	Range N	Actual
1993_07	3.34 .31	2.37-4 44	3.07	6.84 .35	5.99-7.5 44	6.35	112.16 6.44	100-130 44	111.7
1994_01	3.40 .28	2.5-4 51	4.26	6.26 .38	5.5-7 51	7.63	113.10 5.90	100-140 49	98.51
1994_07	4.67 .60	3.15-8 58	5.68	7.30 .39	6.5-8.1 58	7.89	106.85 3.69	99-115 52	99.6
1995_01	6.50 .49	4.89-7.5 59	5.6	7.94 .38	6.8-8.6 59	6.63	104.09 4.00	95-117 57	84.78
1995_07	5.44 .56	4-7.04 62	5.1	6.61 .52	5.75-8.05 62	5.96	89.23 4.24	80-100 60	103.28
1996_01	4.98 .45	3.5-6.25 64	5.18	6.03 .44	5-7.5 64	6.9	104.71 4.56	87-112 62	109.48
1996_07	5.31 .40	4.18-6.3 58	5.21	6.86 .47	5.45-7.7 58	6.65	109.99 4.25	98-120 56	115.77
1997_01	5.16 .41	4.4-6.5 57	5.25	6.52 .52	5-7.6 57	6.8	113.45 4.15	100-122 55	114.61
1997_07	5.41 .35	4.58-6.3 55	5.36	6.79 .40	5.8-7.5 55	5.93	114.89 4.66	105-125 54	130.45
1998_01	5.18 .30	4.25-6 56	5.1	6.02 .37	5.2-6.95 56	5.62	130.41 7.03	115-145 54	138.29
1998_07	5.08 .25	4.25-5.5 55	4.48	5.72 .36	5-6.38 55	5.09	141.28 10.38	120-172 53	113.08
1999_01	4.20 .33	3.5-5 54	4.78	5.05 .44	4.25-6.8 54	5.98	122.77 9.93	100-150 52	120.94
1999_07	4.89 .34	3.7-5.6 54	5.33	5.83 .48	4.5-7 54	6.48	124.75 7.19	110-145 53	102.16
2000_01	5.58 .35	4.5-6.25 53	5.88	6.38 .40	4.8-7.13 53	5.9	105.32 7.20	90-132 53	106.14
2000_07	6.11 .41	5-6.9 53	5.89	6.01 .39	5-7.1 53	5.46	105.34 5.94	90-126 53	114.35
2001_01	5.36 .38	4.3-6.4 52	3.65	5.35 .31	4.5-6 54	5.75	113.21 5.39	97-127 53	124.73
2001_07	3.39 .42	2.7-5.35 54	1.74	5.28 .40	4-6 54	5.07	126.48 6.18	113-140 54	131.04
2002_01	1.89 .32	1.25-2.5 55	1.7	5.06 .51	3.75-6 55	4.86	132.76 7.34	117-115 55	119.85
2002_07	2.19 .33	1.5-3 54	1.22	5.21 .36	4-6.25 55	3.83	123.58 6.53	110-143 55	118.75

Note: Survey respondents are asked early in January and July for their forecasts for the last business day of July and December, respectively. The mean, standard deviation (S.D.) and range of the forecasts in each survey are shown. The number of respondents (N) varies across surveys. The actual values of the variables forecasted are shown in the "Actual" column.

Table 2
Participants Responding To At Least Twenty Surveys

Person	Firm	start	end	gaps	missing dates
David Berson	Fannie Mae	199001	200207	0	
Paul Boltz	T. Rowe Price	198401	199801	0	
Philip Braverman		198401	199901	0	
	Briggs Schaedle	198401	198807		
	Irving Securities	198901	198907		
	DKB Securities	199001	199901		
Dewey Daane	Vanderbilt Univ.	198807	200207	0	
Robert Dederick	Northern Trust	198607	199607	0	
Gail Fosler	Conference Board	199101	200207	0	
Maury Harris		198607	200207	0	
	Paine Webber Inc.	198607	200007		
	UBS Warburg	200107	200207		
Richard Hoey		198401	199401	1	199107
	A.G. Becker	198401	198407		
	Drexel Burnham	198501	199101		
	Dreyfus Corp.	199201	199401		
Stuart G. Hoffman	PNC Bank, Fin Serv	198801	200207	1	199401
William Hummer		199301	200207	0	
	Wayne Hummer	199301	199707		
	Hummer Invest.	199807	200207		
Edward Hyman		198301	200207	1	198901
	C.J. Lawrence	198301	199107		
	ISI Group	199201	200207		
Saul Hymans	Univ. of Michigan	198607	200207	0	for yen:199407 199607 199807 199901
David Jones	Aubrey G. Lanston	198201	199301	0	
Irwin Kellner	ManuHan-Chem-Chase	198201	199701	1	198407
Carol Leisenring	CoreStates Finl.	198707	199801	0	
Alan Lerner		198201	199307	1	198401
	Bankers Trust	198201	199207		
	Lerner Consulting	199301	199301		
Mickey Levy		198507	200207	0	
	Fidelity Bank	198507	199107		
	CRT Govt. Securities	199201	199307		
	NationsBank Cap. Mk	199401	199807		
	Bank of America	199901	200207		
Arnold Moskowitz		198401	200007	1	198807
	Dean Witter	198401	199107		
	Moskowitz Capital	199201	200007		
John Mueller	LBMC	199107	200207	2	199401 199507
Elliott Platt	Donaldson Lufkin(DLJ)	198807	200001	1	199207
Maria Ramirez		199207	200207	1	199401
	Ramirez Inc.	199207	199307		
	MF Ramirez	199407	200107		
	MFR	200201	200207		
Donald Ratajczak		198701	200101	0	
	Georgia State Univ.	198701	200001		
	Morgan Keegan	200007	200101		
David Resler		198407	200207	0	
	First Chicago	198407	198701?		
	Nomura Securities I	198707	200207		
Alan Reynolds		198607	200001	1	199501
	Polyconomics	198607	199107		
	Hudson Institute	199201	200001		
Richard Rippe		199001	200207	0	
	Dean Witter	199001	199107		
	Prudential Securities	199201	200207		

Table 2, continued
Participants Responding To At Least Twenty Surveys

Person	Firm	start	end	gaps	missing dates
Norman Robertson		198201	199601	1	199407
	Mellon Bank	198207	199207		
	Carnegie Mellon	199301	199601		
A. Gary Shilling	Shilling & Co.	198201	200207	4	198307 198401 198901 198907
Alan Sinai		198201	200207		198807 199707
	Data resources	198207	198307		
	Lehman Bros Shearson	198401	198801		
	The Boston Co.(Lehman)	198901	199207		
	Economic Advisors Inc (Lehman)	199301	199307		
	Lehman Brothers	199401	199701		
	WEFA Group	199801	199801		
	(Primark) Decision Economic	199807	200207		
James Smith		198701	200207	2	198807 199401
	UT-Austin	198701	198801		
	Univ. of N.C.	198901	199901		
	Natl Assn of Realtors	199907	200001		
	Univ. of N.C.	200007	200207		
Donald Straszheim		198607	200207	11	198807 199707-200201
	Merril Lynch	198607	199701		
	Strszheim Global Advisors	200207	200207		
Raymond Worseck	A.G. Edwards	198901	199901	0	
David Wyss		198401	200207	4	198807 199407(yen) 200001-200101
	Data Resources	198401	199907		
	Standard & Poor's (McGraw-Hill)	200107	200207		
Edward Yardeni		198607	200007	1	198807
	Prudential Bache	198607	199107		
	C.J. Lawrence	199201	199507		
	Deutsche Bank	199601	200007		

Table 3
Unbiasedness and Accuracy of Treasury Bill Rate Forecasts

Individual	Liu-Maddala Restricted CointegrationTest of Unbiasedness		Mean Forecast Error and t-test for Unbiasedness	Fraction of Correct Directions (p-value for independence test)[a]	χ^2 and Pesaran-Timmerman Tests of Independence[b]	Accuracy	
	ADF(forecast) ADF(Δforecast)	ADF(error) Q(4)				Σ (A-F)^2 n	MSE Ratio to Random Walk (Modified DM statistic)[c]
David	-3.149**	-2.426**	-.351	.577	.735	17.488	.877
Berson	-3.030**	4.260	(-2.369)**	(.453)	.765	26	(-.754)
Paul	-2.720*	-2.901***	-.460	.517	.348	39.928	1.929
Boltz	-2.833*	.541	(-2.257)**	(.694)	.361	29	(1.810)*
Phillip	-3.768***	-4.680***	.203	.483	1.178	37.695	1.780
Braverman	-3.931***	1.696	(1.027)	(.368)	1.217	31	(1.225)
Dewey	-2.289	-2.775***	-.382	.517	.348	21.981	.984
Daane	-3.632**	2.200	(-2.584)**	(.694)	.361	29	(-.066)
Robert	-1.559	-2.758***	-.084	.524	.029	13.270	1.008
Dederick	-2.984**	2.752	(-.477)	(1.000)	.031	21	(.039)
Gail	-3.171**	-3.313***	-.514	.542	.697	25.241	1.402
Fosler	-4.061***	6.633	(-2.776)**	(.653)	.728	24	(1.370)
Maury	-1.571	-3.185***	-.092	.545	.308	22.264	.958
Harris	-3.275**	2.009	(-.639)	(.728)	.318	33	(-.211)
Richard	-1.660	-2.290**	-.425	.350	.848	25.598	1.674
Hoey	-2.334	3.560	(-1.765)*	(.613)	.892	20	(1.698)
Stuart G.	-1.954	-3.245***	-.164	.621	1.830	20.978	.966
Hoffman	-3.870***	.842	(-1.043)	(.264)	1.896	29	(-.160)
William	-2.047	-1.819*	-.380	.600	1.250	14.282	1.038
Hummer	-2.516	2.019	(-2.190)**	(.582)	1.316	20	(.220)
Edward	-1.784	-4.399***	.289	.564	.416	47.690	1.515
Hyman	-4.026***	6.248	(1.672)	(.706)	.427	39	1.076
Saul	-2.545	-2.828***	-.196	.455	.203	28.911	1.245
Hymans	-3.900***	8.681	(-1.210)	(.733)	.209	33	(2.010)*
David	-1.701	-2.770***	-.316	.391	1.245	67.325	1.533
Jones	-4.117***	4.205	(-.882)	(.400)	1.301	23	(1.052)
Irwin	-3.635**	-4.828***	-.102	.333	3.274*	51.619	1.190
Kellner	-4.854***	1.172	(-.421)	(.141)	3.387*	30	(1.480)
Carol	-1.669	-2.430**	.025	.455	.188	12.913	.982
Leisenring	-3.114**	3.773	(.147)	(1.000)	.197	22	(-.081)
Alan	-1.765	-3.887***	-.583	.652	1.806	51.187	1.188
Lerner	-5.333***	6.775	(-1.990)*	(.221)	1.888	23	(.505)
Mickey	-2.409	-3.810***	-.152	.514	.000	28.724	1.175
Levy	-4.476***	3.691	(-.991)	(1.000)	.000	35	(.888)

Arnold	-2.800*	-3.934**	-.078	.333	4.332**	36.167	1.863
Moskowitz	-4.842***	3.671	(-.425)	(.072)*	4.468**	33	(1.512)
John	-2.937*	-2.221**	-.310	.238	5.743**	26.525	1.711
Mueller	-3.442**	3.907	(-1.512)	(.030)**	6.030**	21	(.996)
Elliott	-2.725*	-3.248***	.077	.522	.034	14.410	1.092
Platt	-3.202**	2.597	(.461)	(1.000)	.035	23	(.379)
Maria	-2.117	-1.692*	-.374	.600	1.684	10.209	.810
Ramirez	-2.585	1.803	(-2.678)**	(.319)	1.772	20	(-.593)
Donald	-2.023	-3.022***	-.135	.586	.909	17.279	.897
Ratajczak	-3.382**	.705	(-.939)	(.462)	.941	29	(-.506)
David	-2.485	-4.401***	-.099	.514	.036	33.284	1.117
Resler	-4.057***	3.540	(-.629)	(1.000)	.037	37	(.658)
Alan	-1.331	-1.995**	.104	.519	.030	23.776	1.662
Reynolds	-2.891*	7.928	(.569)	(1.000)	.031	27	(1.711)*
Richard	-3.192**	-2.583**	-.349	.577	1.009	19.738	.990
Rippe	-3.667**	1.481	(-2.185)**	(.428)	1.049	26	(-.051)
Norman	-2.562	-3.836***	-.207	.571	.289	47.190	1.034
Robertson	-4.123***	3.265	(-.841)	(.701)	.300	28	(.133)
A. Gary	-3.126**	-3.388***	.338	.553	.080	80.992	1.428
Shilling	-5.300***	2.056	(1.446)	(1.000)	.082	38	(1.110)
Alan	-2.086	-4.063***	-.278	.525	.102	59.551	1.075
Sinai	-4.320***	5.303	(-1.459)	(1.000)	.105	40	(.292)
James	-2.660	-2.577**	.202	.467	1.701	46.689	2.415
Smith	-3.588**	9.800*	(.882)	(.358)	1.760	30	(2.560)**
Donald	-1.035	-2.347**	-.076	.524	.002	12.906	1.171
Straszheim	-1.936	2.171	(-.465)	(1.000)	.002	22	(.169)
Raymond	-2.049	-2.390**	-.291	.524	.404	15.336	1.464
Worseck	-2.828*	1.238	(-1.619)	(.656)	.424	21	(1.657)
David	-2.208	-4.242***	-.210	.559	.215	30.722	1.336
Wyss	-3.958***	2.417	(-1.301)	(.728)	.222	34	(1.180)
Edward	-1.928	-2.626***	.254	.393	4.044*	20.197	1.690
Yardeni	-3.110**	.868	(1.626)	(.102)	4.194*	28	(2.339)**
Survey	-2.647	-4.309***	-.223	.524	.096	51.444	.891
Mean	-4.950***	1.709	(-1.318)	(1.000)	.098	42	(-557)

Notes:
***, **, * signify statistical significance at the .01, .05, and .10 levels
[a] The number in parentheses is the significance level of the test for independence of predicted and actual changes using the Fisher exact test.
[b] These are Chi-square statistics for the test of independence of predicted and actual changes, see Pesaren and Timmerman (1992)
[c] The modified DM test is the modification of the Diebold-Mariano (1995) test of differences in squared forecast errors given in Harvey *et al* (1997).

Table 4
Unbiasedness and Accuracy of Treasury bond Rate Forecasts

Individual	Liu-Maddala Restricted Cointegration Test of Unbiasedness ADF(forecast) ADF(Δforecast)	 ADR(error) Q(4)	Mean Forecast Error and t-test for Unbiasedness	Fraction of Correct Directions (p-value for independence)	χ^2 and Pesaran-Timmerman Tests of Independence	Forecast Accuracy Σ (A-F)^2 n	 MSE Ratio to Random Walk (Modified DM statistic)
David Berson	-1.424 -5.626***	-4.789*** 8.454	-.163 (-1.074)	.269 (.043)**	5.110** 5.310**	15.612 26	1.388 (2.963)***
Paul Boltz	-3.171** -3.529**	-2.857*** 2.837	-.455 (-2.216)**	.414 (.669)	.232 .240	40.280 29	1.664 (2.199)**
Phillip Braverman	-5.037*** -4.235***	-3.891*** 1.226	.269 (1.298)	.581 (1.000)	.057 .059	42.084 31	1.664 (1.377)
Dewey Daane	-2.382 -6.463***	-4.107*** 4.773	-.490 (-3.254)***	.310 (.164)	2.653 2.748	25.412 29	2.088 (2.431)**
Robert Dederick	-1.894 -4.943***	-4.993*** 4.133	-.046 (-.254)	.409 (.659)	.833 1.458	13.946 21	1.533 (2.216)**
Gail Fosler	-1.312 -4.553***	-2.392** 7.005	-.590 (-3.742)***	.500 (.615)	.825 .861	22.078 24	1.999 (2.187)**
Maury Harris	-1.191 -4.870***	-5.221*** 8.784	.095 (.713)	.545 (1.000)	.021 .021	19.213 33	1.426 (1.668)
Richard Hoey	-2.140 -2.535	-2.602** 11.496**	-.443 (-1.414)	.300 (.160)	3.039* 3.199*	41.128 20	2.135 (2.274)**
Stuart G. Hoffman	-1.695 -5.522***	-4.168*** 4.667	-.183 (-1.462)	.345 (.128)	3.131* 4.137**	13.755 29	1.304 (1.942)*
William Hummer	-1.631 -4.453***	-3.236*** 10.435*	-.387 (-2.434)**	.300 (.290)	1.832 1.928	12.605 20	1.300 (1.354)
Edward Hyman	-1.501 -5.486***	-4.109*** 7.866	.501 (2.743)***	.538 (1.000)	.030 .031	59.230 39	2.123 (1.801)*
Saul Hymans	-1.402 -5.948***	-5.403*** 12.111**	-.186 (-1.390)	.455 (1.000)	.122 .520	20.005 33	1.486 (2.073)*
David Jones	-2.074 -3.742**	-3.124*** 2.073	-.276 (-1.006)	.478 (1.000)	.048 .050	39.840 23	1.252 (.967)
Irwin Kellner	-2.579 -7.460***	-4.899*** 7.124	-.159 (-.767)	.433 (.272)	2.143 2.217	38.332 30	1.190 (.676)
Carol Leisenring	-1.522 -6.388***	-5.804*** 8.473	-.010 (-.067)	.591 (.655)	.282 .002	10.413 22	1.175 (.941)
Alan Lerner	-2.183 -4.813***	-3.882*** 4.164	-.523 (-1.921)*	.652 (.685)	1.806 .320	43.875 23	1.525 (2.129)**
Mickey Levy	-2.581 -7.662***	-6.895*** 5.468	-.088 (-.571)	.514 (1.000)	.008 .150	28.397 35	1.471 (2.153)**

Arnold	-2.831*	-5.387***	.012	.424	1.636	45.956	1.764
Moskowitz	-6.454***	5.660	(.055)	(.278)	1.688	33	(1.706)*
John	-1.397	-1.842*	-.362	.381	1.527	16.028	1.796
Mueller	-4.429***	7.100	(-2.035)*	(.361)	1.604	21	(2.154)**
Elliott	-2.569	-4.729***	.069	.435	.434	16.210	1.593
Platt	-4.903***	4.268	(.385)	(.680)	.454	23	(2.221)**
Maria	-1.435	-2.077**	-.456	.350	.019	9.906	1.206
Ramirez	-5.654***	4.222	(-3.708)***	(1.000)	.020	20	(.949)
Donald	-1.152	-5.111***	-.092	.310	3.948**	17.389	1.469
Ratajczak	-4.745***	5.544	(-.634)	(.067)*	5.798**	29	(2.948)***
David	-3.229**	-4.442***	.018	.541	.315	37.129	1.510
Resler	-4.704***	3.581	(.105)	(.687)	1.016	37	(2.558)**
Alan	-1.482	-2.964***	.204	.407	1.187	20.397	2.031
Reynolds	-3.878***	2.142	(1.229)	(.420)	1.232	27	(2.778)**
Richard	-1.196	-3.391***	-.137	.308	3.718**	15.103	1.343
Rippe	-6.679***	3.371	(-.911)	(.105)	3.867**	26	(1.472)
Norman	-2.248	-4.526***	-.201	.286	5.320**	45.725	1.254
Robertson	-4.483***	3.287	(-.828)	(.030)**	5.517**	28	(2.124)**
A. Gary	-2.636*	-3.083***	.534	.553	.011	63.702	1.761
Shilling	-5.943***	2.280	(2.754)***	(1.000)	.011	38	(2.111)**
Alan	-2.275	-5.222***	-.027	.500	.234	51.929	1.293
Sinai	-5.397***	4.684	(-.146)	(.730)	.240	40	(1.299)
James	-1.391	-4.429***	.604	.600	.599	37.865	3.222
Smith	-5.143***	3.802	(3.431)***	(1.000)	.620	30	(2.228)**
Donald	-1.120	-4.463***	.004	.476	.043	15.843	1.560
Straszheim	-4.352***	5.540	(.021)	(1.000)	.046	22	(2.291)**
Raymond	-.587	-3.240***	-.177	.429	.531	14. 601	1.503
Worseck	-4.222***	2.295	(-.972)	(.659)	1.458	21	(1.803)*
David	-3.683**	-4.753***	-.137	.294	6.103**	31.063	1.147
Wyss	-4.514***	3.412	(-.831)	(.032)**	6.287**	34	(.906)
Edward	-1.152	-3.493***	.575	.536	.778	25.757	2.182
Yardeni	-5.295***	7.406	(3.896)***	(1.000)	.807	28	(2.346)**
Mean	-2.459	-5.570***	-.135	.333	6.133**	46.418	1.132
	-5.832***	7.109	(-.832)	(.024)**	6.283**	42	(1.072)
Notes: See notes to Table 3							

Table 5
Unbiasedness and Accuracy of Yen-Dollar Exchange Rate Forecasts

Individual	Liu-Maddala Restricted Cointegration Test of Unbiasedness ADF(forecast) ADF(Δforecast)	 ADF(error) Q(4)	Mean Forecast Error and t-test for Unbiasedness	Fraction of Correct Directions (p-value for independence)	χ^2 and Pesaran-Timmerman Tests of Independence	Forecast Accuracy Σ (A-F)^2 n	 MSE Ratio to Random Walk (Modified DM statistic)
David	-2.504	-2.721***	-3.118	.385	2.275	5175.980	1.518
Berson	-3.589**	1.681	(-1.133)	(.217)	2.366	26	(2.452)**
Paul	-1.122	-2.120**	2.563	.474	.003	3301.963	1.397
Boltz	-2.735*	4.258	(.841)	(1.000)	.003	19	(1.930)*
Phillip	-2.007	-2.847***	-.204	.667	2.291	3404.713	1.113
Braverman	-3.097**	1.481	(-.072)	(.198)	2.405	21	(.381)
Dewey	-2.105	-3.209***	2.873	.393	1.011	6518.140	1.729
Daane	-3.535**	3.265	(.996)	(.441)	1.048	28	(2.012)*
Robert	-.791	-2.185**	1.146	.563	.152	3109.605	1.518
Dederick	-2.042	3.752	(.320)	(1.000)	.163	16	(1.921)*
Gail	-3.116**	-2.699**	2.701	.542	.697	4957.834	1.621
Fosler	-3.357**	3.660	(.918)	(.653)	.728	24	(1.828)*
Maury	-1.917	-2.695**	-2.724	.571	.324	5034.540	1.336
Harris	-3.212**	3.536	(-1.078)	(.698)	.336	28	(1.642)
Richard	-1.370	-1.984**	4.253	.500	.000	2685.864	2.170
Hoey	-2.073	3.865	(.786)	(1.000)	.000	10	(2.201)**
Stuart G.	-1.874	-2.980***	-1.251	.444	.759	4941.500	1.374
Hoffman	-2.827*	3.403	(-.474)	(.448)	.788	27	(2.028)*
William	-1.755	-2.432**	.240	.550	.135	3451.686	1.197
Hummer	-2.847*	2.423	(.080)	(1.000)	.142	20	(1.400)
Edward	-2.179	-2.260**	-5.529	.543	.675	5159.600	1.513
Hyman	-3.404**	2.403	(-2.225)**	(.569)	.701	27	(2.025)*
Saul	-1.982	-2.291**	1.873	.458	.084	3194.330	1.055
Hymans	-2.312	3.291	(.789)	(1.000)	.088	25	(.593)
David	-.792	-1.722*	.136	.444	.225	1648.664	1.364
Jones	-1.962	2.238	(.028)	(1.000)	.253	9	(2.071)*
Irwin	-1.135	-2.831***	3.762	.647	2.082	2955.657	1.442
Kellner	-3.155**	3.259	(1.191)	(.294)	2.212	17	(1.056)
Carol	-1.138	-1.947*	-.385	.526	.003	2809.424	1.190
Leisenring	-1.606	4.245	(-.134)	(1.000)	.003	19	(.904)
Alan	-1.537	-.814	-7.008	.500	.476	2839.654	2.301
Lerner	-2.670*	2.892	(-1.372)	(1.000)	.529	10	(2.358)**
Mickey	-1.842	-2.598**	-3.438	.607	.778	4672.100	1.239
Levy	-3.257**	4.886	(-1.435)	(.560)	.867	28	(1.350)

Arnold Moskowitz	-1.373 -2.827*	-2.315** 2.750	-2.802 (-.960)	.583 (.673)	.243 .358	4893.624 24	1.399 (1.635)
John Mueller	-2.405 -2.739*	-2.550** 3.444	2.911 (1.063)	.524 (.659)	.311 .327	3329.745 21	1.311 (.826)
Elliott Platt	-1.764 -3.366**	-2.376** 3.983	-1.493 (-.495)	.636 (.384)	1.352 1.416	4245.175 22	1.239 (1.331)
Maria Ramirez	-2.369 -2.784*	-2.648** 6.150	-2.993 (-.920)	.500 (1.000)	.159 .167	4202.448 20	1.550 (1.908)*
Donald Ratajczak	-1.683 -3.186**	-3.075*** 3.363	2.600 (.927)	.400 (.653)	.329 .343	4886.268 25	1.357 (1.716)*
David Resler	-1.673 -3.116**	-2.991*** 4.052	-1.367 (-.580)	.536 (1.000)	.050 .052	4245.559 28	1.126 (1.132)
Alan Reynolds	-1.309 -2.814*	-2.296** 2.255	-.762 (-.279)	.591 (.666)	.627 .657	3470.269 22	1.082 (.466)
Richard Rippe	-2.688* -3.759***	-2.942*** 1.791	.305 (.118)	.577 (.453)	.735 .765	4343.981 26	1.275 (1.621)
Norman Robertson	-.327 -2.730*	-2.072** 2.063	-.216 (-.058)	.571 (1.000)	.286 .308	2517.032 14	1.254 (1.109)
A. Gary Shilling	-2.298 -3.653**	-1.483 2.917	-13.233 (-3.983)***	.538 (1.000)	.763 .793	11728.621 26	3.441 (3.582)***
Alan Sinai	-2.613 -3.434**	-2.506** 3.374	-1.653 (-.554)	.519 (1.000)	.008 .008	6320.800 27	1.796 (1.654)
James Smith	-1.800 -4.013***	-1.616 3.248	-11.881 (-4.713)***	.630 (.407)	1.511 1.569	9506.039 27	2.644 (2.294)**
Donald Straszheim	-1.093 -3.058**	-3.770*** 4.067	1.350 (.476)	.588 (.620)	.701 .745	2237.738 18	1.092 (.293)
Raymond Worseck	-1.305 -3.308**	-1.530 6.685	-3.109 (-1.003)	.571 (.673)	.269 .283	4235.650 21	1.385 (1.297)
David Wyss	-2.522 -3.551**	-2.805*** 2.847	.080 (.024)	.542 (1.000)	.168 .175	6049.966 24	1.693 (3.278)***
Edward Yardeni	-1.578 -2.717*	-2.302** 2.356	-4.860 (-1.810)*	.667 (.163)	3.055 3.187	4546.241 24	1.300 (1.360)
Mean	-1.941 -3.147**	-2.838*** 3.596	-1.529 (-.645)	.464 (.687)	.491 .509	4594.172 28	1.219 (2.114)**
Notes: See notes to Table 3							

Table 6
Tests of Heterogeneity of Forecasts Across Survey Respondents

Dependent variable: Deviation of an individual's time t forecast from the mean time t forecast

Data set	Panel 1[3]			Panel 2[4]		
Number of forecasters	93	93	79	33	33	33
Number of forecasts	1650	1650	1280	924	924	722
Forecast variable	T-Bill rate	T-Bond rate	Yen/$ rate	T-Bills rate	T-Bonds Rate	Yen/$ Rate
Panel A: Models with Individual Dummy Variables						
Tests for individual effects[1]	4.09***	8.63***	6.76***	5.96***	15.38***	12.23***
Panel B: Models with Employment Dummy Variables						
Banks	-.009 (.039)	-.025 (.038)	.837 (.594)	-.013 (.056)	-.041 (.053)	.343 (.784)
Security firms	-.044 (.036)	-.145*** (.035)	.423 (.540)	-.054 (.049)	-.136*** (.046)	-.175 (.656)
Independent Forecasters	-.158*** (.044)	-.262*** (.043)	1.653** (.653)	-.240*** (.062)	-.350*** (.059)	2.618*** (.824)
Corporate forecasters	-.033 (.083)	-.090 (.080)	1.874 (1.214)	na	Na	na
Econometric models	-.047 (.064)	-.107 (.062)	-1.483 (.974)	.014 (.077)	-.062 (.074)	-2.552** (1.113)
Constant	.047 (.031)	.108 (.030)	-.582 (-1.28)	.015 (.041)	.069 (.039)	-.454 (.529)
F test for differences across employers[2]	3.46***	10.91***	2.93**	4.95***	10.58***	5.92***

, * represent statistical significance at the .05 and .01 levels
[1] This F statistic tests that the coefficients for all individuals are the same.
[2] This F statistic tests that the coefficients for all employer types are the same.
[3] Panel 1 includes all economists having at least 6 forecasts.
[4] Panel 2 includes all economists having at least 20 forecasts.

Table 7
OLS Estimates of Incentives Model

Dependent variable: Absolute value of the deviation of an economist's time t forecast from the time t forecast mean excluding that economist

Data set	Panel 1			Panel 2		
Number of forecasters	93	93	79	33	33	33
Number of forecasts	1650	1650	1280	924	924	722
Forecast variable	T-Bill	T-Bond	Yen/$	T-Bill	T-Bond	Yen/$
AGE	-.0018* (.0011)	-.0021** (.0010)	-.0428*** (.0149)	-.0022 (.0015)	-.0029** (.0014)	-.0435** (.0206)
AGE*MODEL	.0002 (.0045)	-.0041 (.0042)	.0214 (.0720)	.0040 (.0054)	-.0011 (.0049)	-.0165 (.0956)
AVEDEV	.8436*** (.0512)	.6983*** (.0765)	.8610*** (.0793)	1.0475*** (.0830)	.9218*** (.1148)	.6490*** (.1108)
OWN	.1697*** (.0382)	.1298*** (.0364)	1.7425*** (.5638)	.2185*** (.0514)	.2042*** (.0470)	1.6198** (.6782)
Independent but not OWN	.0527 (.0333)	.0710** (.0318)	.2293 (.4760)	.0370 (.0505)	.1095** (.0462)	.1236 (.6422)
Banks	-.0742*** (.0269)	-.0944*** (.0257)	-.9469*** (.3983)	-.1388*** (.0396)	-.1574*** (.0362)	-1.9637*** (.5339)
Securities firms	-.0254 (.0248)	.0115 (.0236)	-.3453 (.3616)	-.0844** (.0344)	-.0495 (.0316)	-1.7803*** (.4485)
Corporate forecasters	-.1133** (.0572)	-.0966* (.0539)	-.7845 (.8384)			
Econometric Models	-.1476** (.0334)	-.0974 (.0698)	-1.1935 (1.3083)	-.2706*** (.0962)	-.2020** (.0875)	-1.1726 (1.9129)
Constant	.0979*** (.0334)	.1492*** (.0397)	1.5665*** (.5343)	.0836* (.0502)	.1319** (.0573)	3.4837*** (.7448)
F test for differences across industries	9.20***	10.53***	4.40***	11.82***	14.38***	8.51***
R^2	.185	.097	.101	.218	.150	.100

*, **, and *** represent statistical significance at the .10, .05, and .01 levels

Annual Energy Outlook 2020

with projections to 2050

Independent Statistics & Analysis
U.S. Energy Information Administration

#AEO2020

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Key Takeaways from U.S. Energy Information Administration's *Annual Energy Outlook 2020*

- In the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2020* (AEO2020) Reference case, U.S. energy consumption grows more slowly than gross domestic product throughout the projection period (2050) as U.S. energy efficiency continues to increase. This decline in the energy intensity of the U.S. economy continues through 2050.

- The electricity generation mix continues to experience a rapid rate of change, with renewables the fastest-growing source of electricity generation through 2050 because of continuing declines in the capital costs for solar and wind that are supported by federal tax credits and higher state-level renewables targets. With slow load growth and increasing electricity production from renewables, U.S. coal-fired and nuclear electricity generation declines; most of the decline occurs by the mid-2020s.

- The United States continues to produce historically high levels of crude oil and natural gas. Slow growth in domestic consumption of these fuels leads to increasing exports of crude oil, petroleum products, and liquefied natural gas.

- After falling during the first half of the projection period, total U.S. energy-related carbon dioxide emissions resume modest growth in the 2030s, driven largely by increases in energy demand in the transportation and industrial sectors; however, by 2050, they remain 4% lower than 2019 levels.

The Annual Energy Outlook explores long-term energy trends in the United States

- The value of the projections in the AEO2020 is not that they are predictions of what will happen, but rather, they are modeled projections of what may happen given certain assumptions and methodologies. By varying those assumptions and methodologies, AEO2020 can illustrate important factors in future energy production and use in the United States.

- Energy market projections are subject to much uncertainty because many of the events that shape energy markets—as well as future developments in technologies, demographics, and resources—cannot be foreseen with certainty. To illustrate the importance of key assumptions, AEO2020 includes a Reference case and side cases that systematically vary important underlying assumptions.

- EIA develops the AEO with the National Energy Modeling System (NEMS), an integrated model that captures interactions of economic changes and energy supply, demand, and prices.

- More information about the assumptions EIA used to develop these projections will be available on the AEO website shortly after the release of the AEO2020.

- The AEO is published to satisfy the Department of Energy Organization Act of 1977, which requires the Administrator of the U.S. Energy Information Administration to prepare annual reports on trends and projections for energy use and supply.

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What is the AEO2020 Reference case?

- The AEO2020 Reference case represents EIA's best assessment of how U.S. and world energy markets will operate through 2050, based on key assumptions intended to provide a base for exploring long-term trends.
- The AEO2020 Reference case should be interpreted as a reasonable baseline case that can be compared with the cases that include alternative assumptions.
- EIA based the economic and demographic trends reflected in the Reference case on the current views of leading economic forecasters and demographers. For example, the Reference case projection assumes improvement in known energy production, delivery, and consumption technologies.
- The Reference case generally assumes that current laws and regulations that affect the energy sector, including laws that have end dates, are unchanged throughout the projection period. This assumption makes it possible for us to use the Reference case as a benchmark to compare policy-based modeling.
- The potential effects of proposed legislation, regulations, or standards are not included in the AEO2020 cases.

What are the side cases?

- Oil prices in the future will be driven by global market balances that are primarily influenced by factors that are not modeled in NEMS. In the AEO2020 High Oil Price case, the price of Brent crude oil, in 2019 dollars, reaches $183 per barrel (b) by 2050, compared with $105/b in the Reference case and $46/b in the Low Oil Price case.
- Compared with the Reference case, the High Oil and Gas Supply case reflects lower costs and greater U.S. oil and natural gas resource availability, which allows more production at lower prices. The Low Oil and Gas Supply case assumes fewer resources and higher costs.
- The effects of economic assumptions on the energy consumption modeled in the AEO2020 are addressed in the High Economic Growth and Low Economic Growth cases, which assume compound annual growth rates for U.S. gross domestic product of 2.4% and 1.4%, respectively, from 2019 to 2050, compared with 1.9% per year growth in the Reference case.
- AEO2020 introduces two cases to examine the sensitivities surrounding capital costs for electric power generating technologies. Capital cost reduction for an electric power generating technology is assumed to occur from learning by doing. In the High Renewables Cost case, no cost reduction from learning is assumed for any renewable technologies. The Low Renewables Cost case assumes higher learning for renewable technologies through 2050, resulting in a cost reduction of about 40% from the Reference case by 2050.

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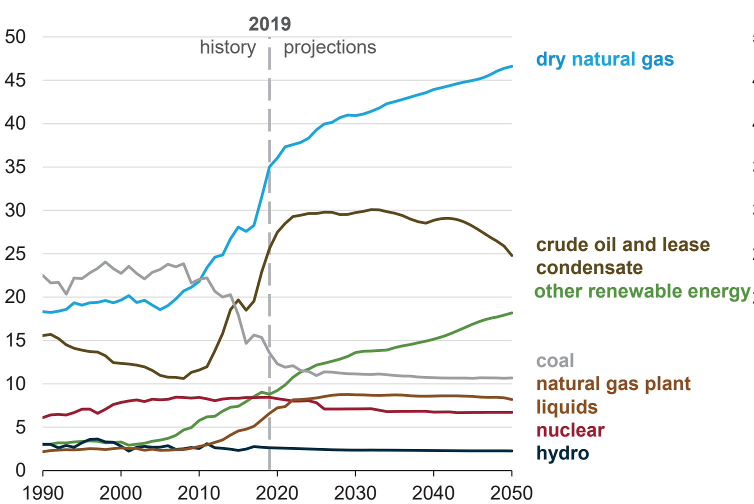
Overview of energy markets

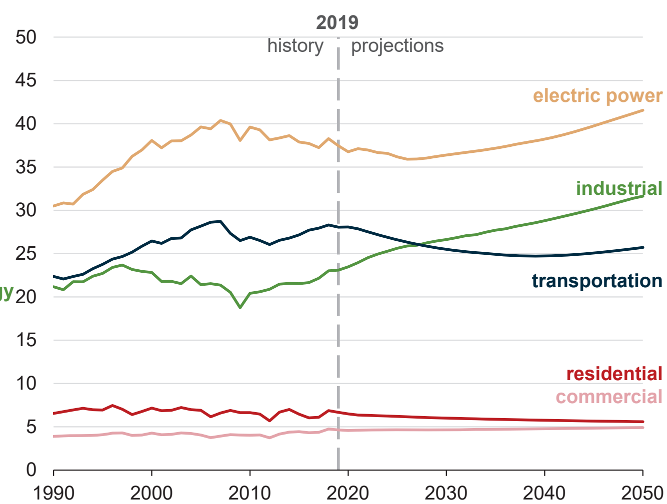
In the Reference case, strong domestic energy production coupled with slow growth in domestic energy demand leads the United States to remain a net energy exporter through 2050. Energy-related carbon dioxide emissions, driven by changes in the electricity generation fuel mix and increasing activity in the transportation and industrial sectors, experience modest growth in the later part of the projection period after falling in the 2020s.

U.S. energy production grows significantly, but consumption grows moderately under the AEO2020 Reference case assumption of current laws and regulations

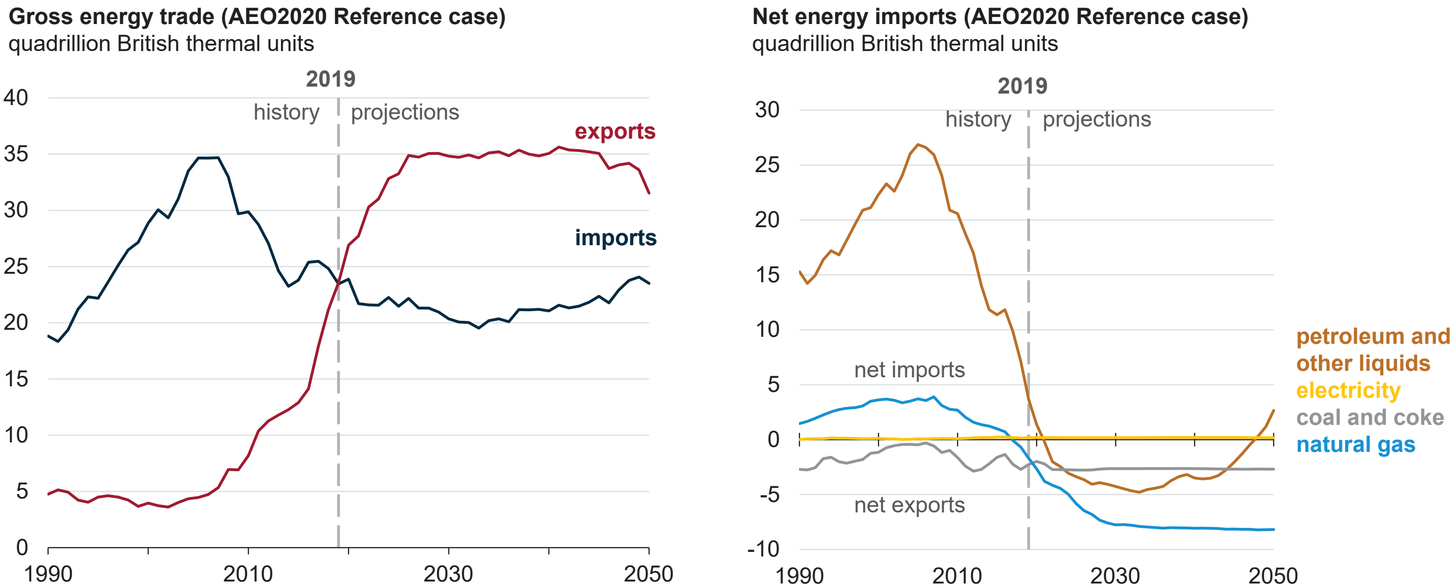
Energy production (AEO2020 Reference case)
quadrillion British thermal units



Energy consumption by sector (AEO2020 Reference case)
quadrillion British thermal units



The United States becomes a net energy exporter on an annual basis by 2020 in the AEO2020 Reference case—

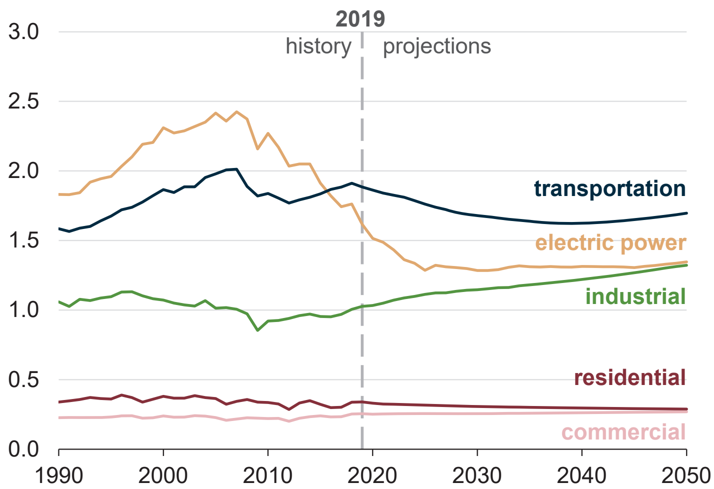


—but the United States continues to import and export energy throughout the projection period

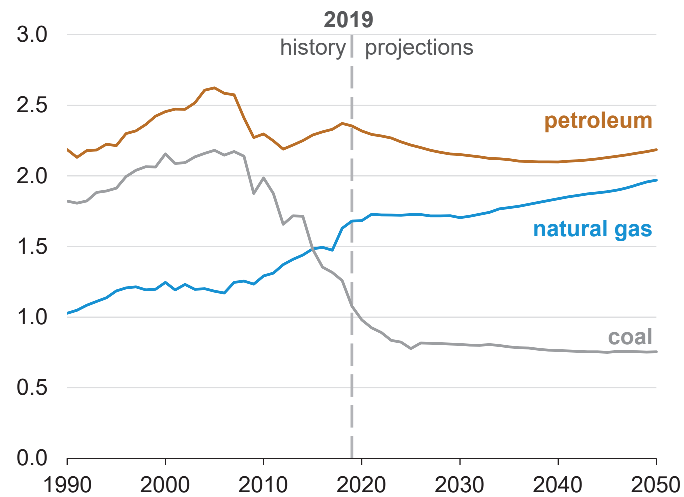
- The United States imported more energy than it exported annually since 1953, but continued growth in petroleum and natural gas exports results in the United States becoming a net energy exporter in 2020 in all AEO2020 cases.
- In the AEO2020 Reference case, the United States exports more petroleum and other liquids than it imports annually starting in 2020 as U.S. crude oil production continues to increase and domestic consumption of petroleum products decreases. Near the end of the projection period, the United States returns to importing more petroleum and other liquids than it exports on an energy basis as a result of increasing domestic gasoline consumption and falling domestic crude oil production after 2047.
- The United States became a net natural gas exporter on an annual basis in 2017 and continued to export more natural gas than it imported in 2018 and in 2019. In the AEO2020 Reference case, liquefied natural gas (LNG) exports to more distant destinations will increasingly dominate the U.S. natural gas trade, and the United States is projected to remain a net natural gas exporter through 2050.
- The United States continues to be a net exporter of coal (including coal coke) through 2050 in the AEO2020 Reference case, but coal exports remain at the same level because of competition from other global suppliers that are closer to major world consumers.

AEO2020 energy-related carbon dioxide emissions increase in the industrial sector, increase as a result of natural gas consumption, but remain relatively flat in other sectors and fuels through 2050

Energy-related CO2 emissions by energy sector (AEO2020 Reference case)
billion metric tons



Energy-related CO2 emissions by fuel (AEO2020 Reference case)
billion metric tons



Critical drivers and model updates

Many factors influenced the results presented in AEO2020, including model improvements, new and existing laws and regulations since AEO2019, and varying assumptions about global oil prices, macroeconomic growth, domestic energy resources and production technology, and technology costs for renewable electricity generation.

Critical drivers and uncertainty

- Future oil prices are highly uncertain and are subject to international market conditions influenced by factors outside of the National Energy Modeling System. The High Oil Price and Low Oil Price cases represent international conditions that could drive prices to extreme, sustained deviations from the Reference case price path. In the High Oil Price case, non-U.S. demand for petroleum and other liquids is higher and non-U.S. supply of liquids is lower; in the Low Oil Price case, the opposite is true.

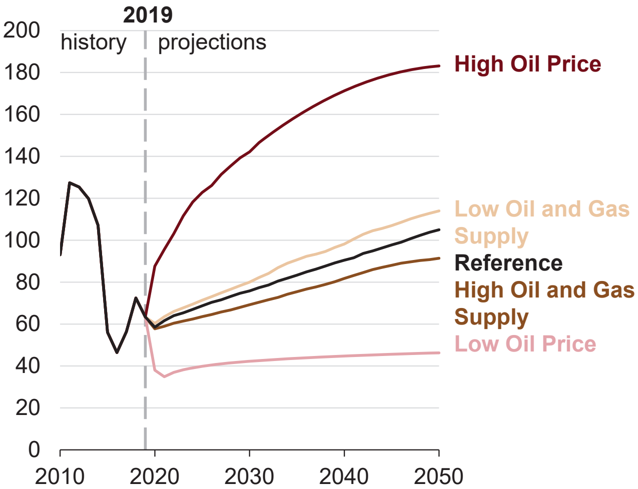
- Projections of tight oil and shale gas production are uncertain because large portions of known formations have relatively little or no production history and extraction technologies and practices continue to evolve rapidly. In the High Oil and Gas Supply case, lower production costs and higher resource availability allow higher production at lower prices. In the Low Oil and Gas Supply case, EIA applied assumptions of lower resources and higher production costs. EIA did not extend these assumptions to outside the United States.

- Economic growth drives energy consumption. The High Economic Growth and Low Economic Growth cases address these effects by modifying population growth and productivity assumptions throughout the projection period to yield higher or lower compound annual growth rates for U.S. gross domestic product (GDP).

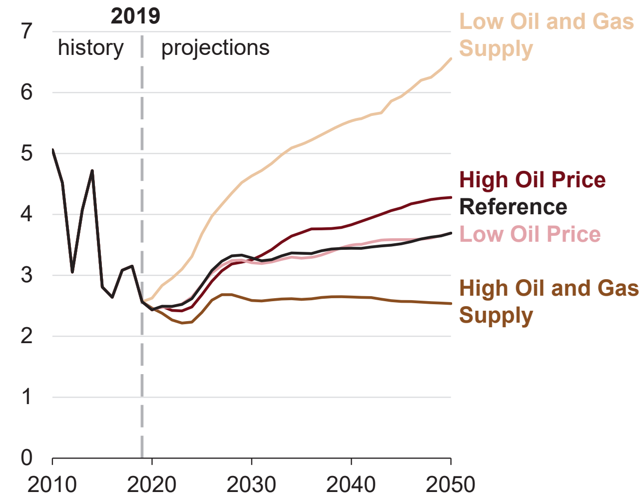
- Costs for renewables such as wind and solar have continued to decline as experience is gained with more builds. How long these high cost reduction rates can be sustained is highly uncertain. The High Renewables Cost case assumes no further cost reduction for renewables, and the Low Renewables Cost case assumes a sustained high rate of cost reduction. The Reference case assumes that cost reduction rates gradually taper off.

EIA develops oil and natural gas price assumptions by considering international supply and demand and the development of U.S. shale resources—

AEO2020 North Sea Brent crude oil price
2019 dollars per barrel



AEO2020 natural gas price at Henry Hub
2019 dollars per million British thermal unit



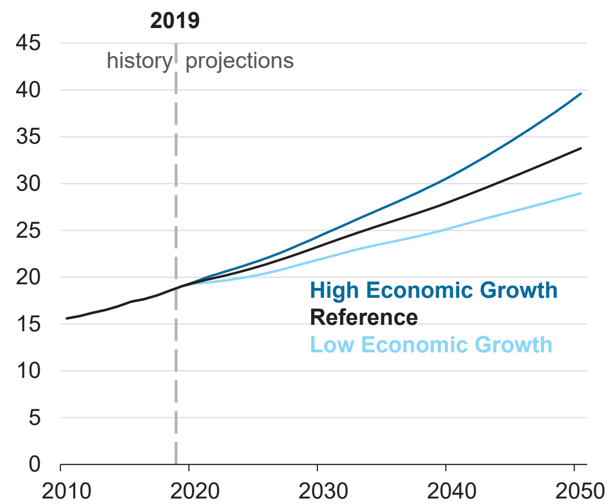
—however, global conditions are more important for oil prices and assumptions about resource and technology are more important for natural gas prices

- EIA's assumed crude oil prices in AEO2020 are influenced more by assessments of international markets than by assumptions about domestic resources and technological advances. In the High Oil Price case, EIA projects the price of Brent crude oil in 2019 dollars to reach $183 per barrel (b) by 2050 compared with $105/b in the Reference case and $46/b in the Low Oil Price case.

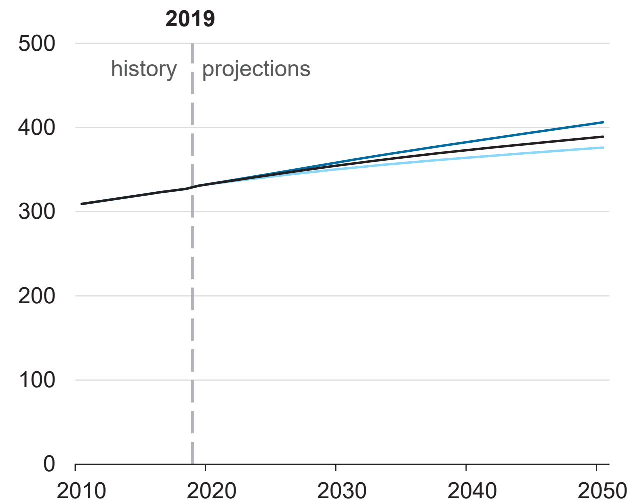
- Natural gas prices are highly sensitive to factors that drive supply, such as domestic resource and technology assumptions, and are less dependent on the international conditions that drive oil prices. In the High Oil and Gas Supply case, Henry Hub natural gas prices remain lower than $3 per million British thermal units ($/MMBtu) throughout the projection period, but in the Low Oil and Gas Supply case, they rise to more than $6/MMBtu during the same period.

Economic growth side cases explore the uncertainty in macroeconomic assumptions inherent in future economic growth trends—

AEO2020 gross domestic product assumptions
trillion 2012 dollars



AEO2020 U.S. population assumptions
millions

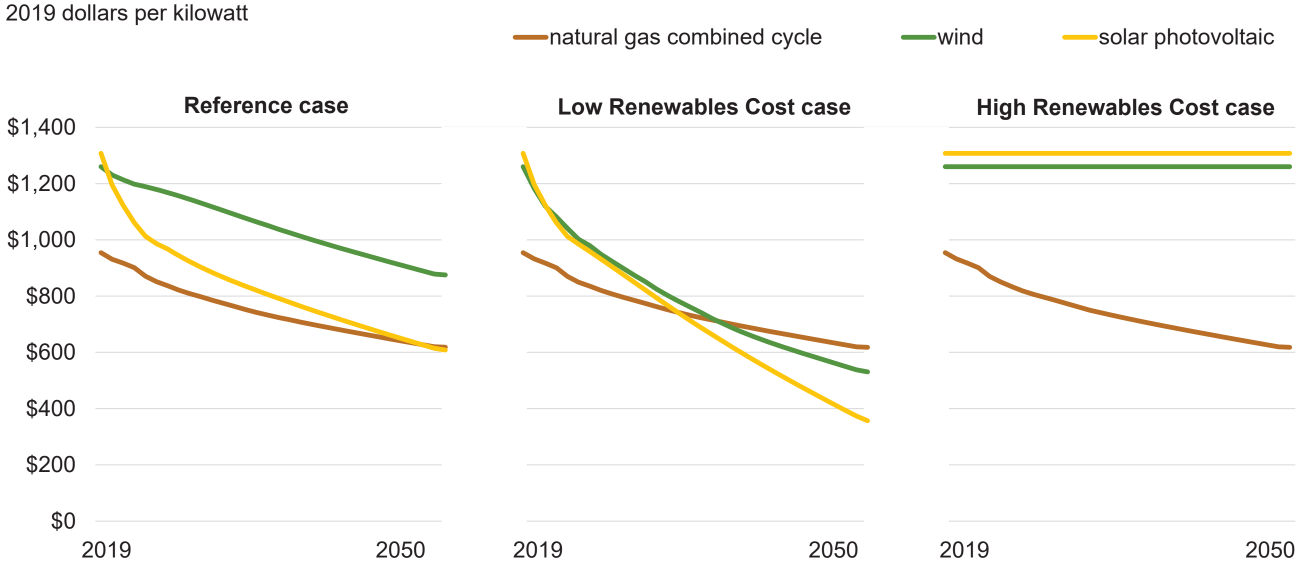


—which also affect important drivers of energy demand growth

- The AEO2020 Reference, High Economic Growth, and Low Economic Growth cases illustrate three possible paths for U.S. economic growth. In the High Economic Growth case, average annual growth in real GDP during the projection period is 2.4%, compared with 1.9% in the Reference case. The Low Economic Growth case assumes a lower rate of annual growth in real GDP of 1.4%.
- Differences among the cases reflect different assumptions for growth in the labor force, capital stock, and productivity. These changes affect capital investment decisions, household formation, industrial activity, and amount of travel.
- All three economic growth cases assume smooth economic growth and do not anticipate business cycles or large economic shocks.

The High Renewables Cost and Low Renewables Cost cases assume different rates of cost reduction for renewable technologies compared with the Reference case; non-renewables assume the same rates

AEO2020 overnight installed cost by technology
2019 dollars per kilowatt

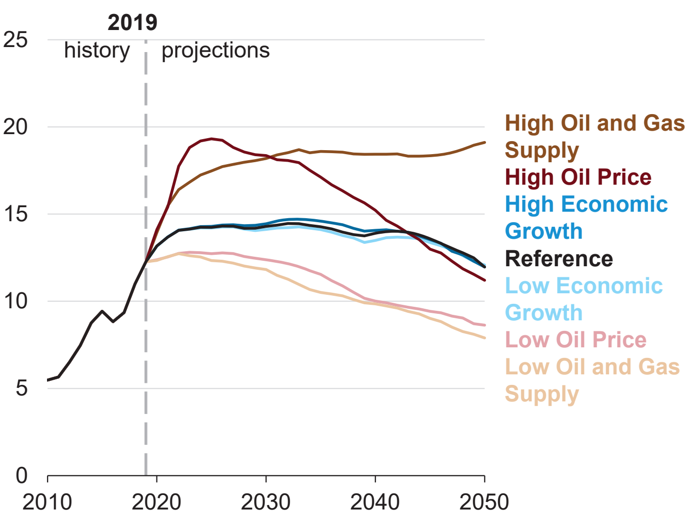


Petroleum and other liquids

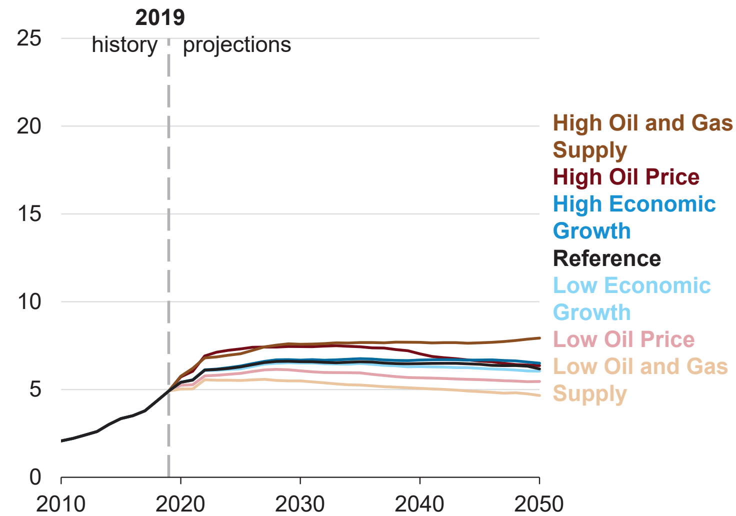
Growth in production of U.S. crude oil and natural gas plant liquids generally continues through 2025, mainly as a result of the continued development of tight oil resources. During the same period, domestic consumption falls, making the United States a net exporter of liquid fuels in the AEO2020 Reference case and in many of the side cases.

Production of U.S. crude oil and natural gas plant liquids continues to grow through 2025 in the AEO2020 Reference case—

AEO2020 U.S. crude oil production
million barrels per day



AEO2020 U.S. natural gas plant liquids production
million barrels per day



—and natural gas plant liquids comprise nearly one-third of cumulative U.S. liquids production during the projection period

- In the AEO2020 Reference case, U.S. crude oil production reaches 14.0 million barrels per day (b/d) by 2022 and remains near this level through 2045 as tight oil development moves into less productive areas and well productivity declines.

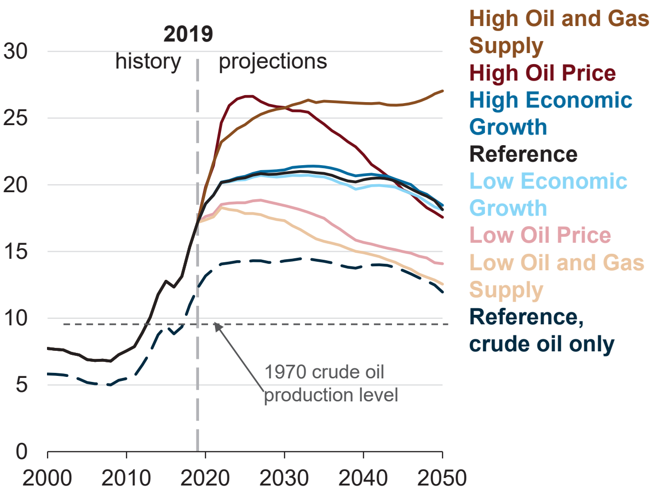
- The continued development of tight oil and shale gas resources in the AEO2020 Reference case supports growth in natural gas plant liquids (NGPL) production, which reaches 6.6 million b/d by 2028. NGPLs are light hydrocarbons predominantly found in natural gas wells and are diverted from the natural gas stream by natural gas processing plants. These hydrocarbons include ethane, propane, normal butane, isobutane, and natural gasoline.

- In the AEO2020 Reference case, NGPL production grows by 26% during the projection period as a result of demand increases by the global petrochemical industry. Most NGPL production growth in the AEO2020 Reference case occurs before 2025 as producers focus on natural gas plant liquids-rich plays, where NGPL-to-gas ratios are highest and increased demand spurs greater ethane recovery.

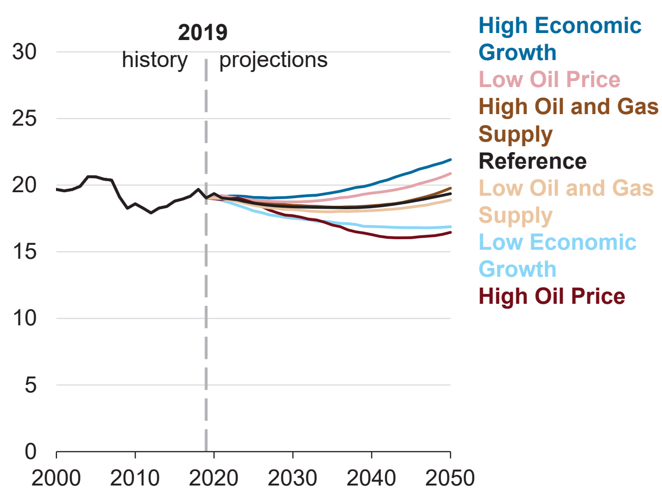
- In the AEO2020 cases, NGPL production is sensitive to changes in resource and technology assumptions, as well as oil price assumptions. In the High Oil and Gas Supply case, which has faster rates of technological improvement, higher recovery estimates, and additional tight oil and shale gas resources, NGPL production grows by 61% during the projection period. In the High Oil Price case, high crude oil prices lead to more drilling in the near term, but cost increases and fewer easily accessible resources decrease production of crude oil and NGPLs later in the forecast period.

Although production continues to grow through 2025, consumption of petroleum and other liquids remains lower than its 2004 peak level through 2050 in most cases

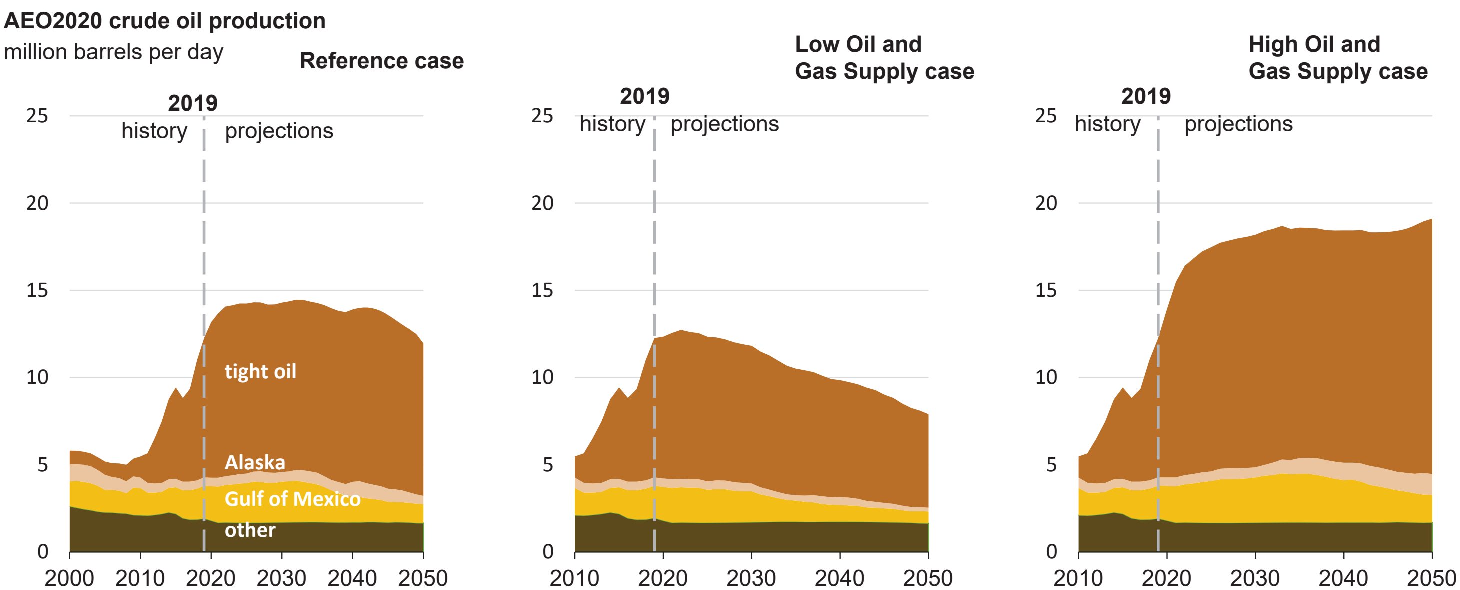
AEO2020 U.S. crude oil and natural gas plant liquids production
million barrels per day



AEO2020 petroleum and other liquids consumption
million barrels per day



Tight oil development drives U.S. crude oil production during the AEO2020 projection period—



—which is consistent across all AEO2020 side cases

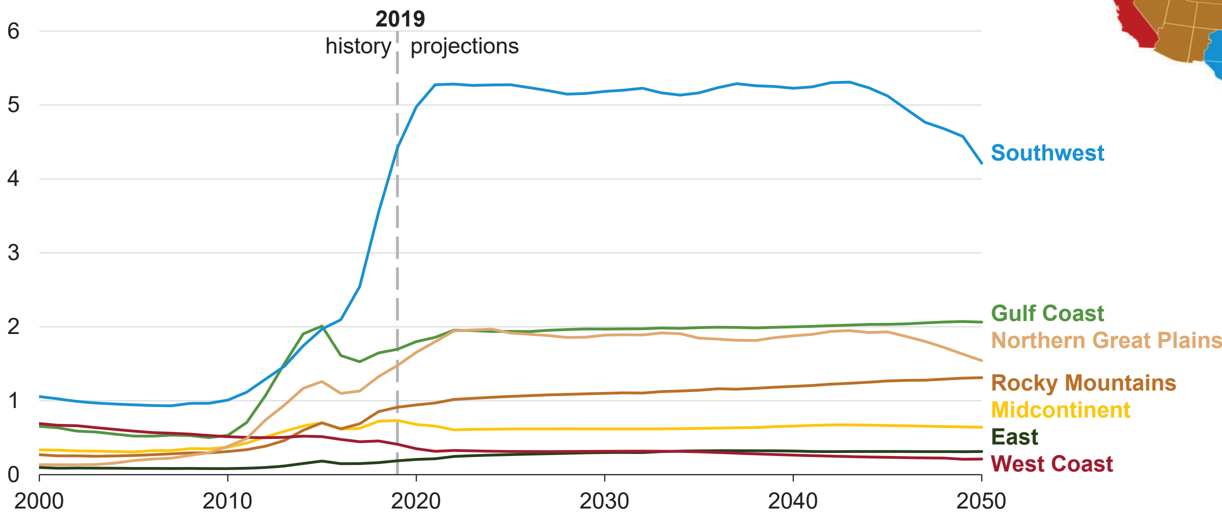
- Onshore tight oil development in the Lower 48 states continues to be the main driver of total U.S. crude oil production, accounting for about 70% of cumulative domestic production in the AEO2020 Reference case during the projection period.

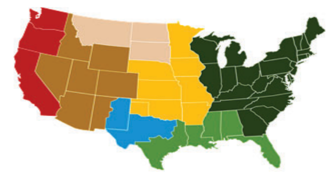
- In the AEO2020 Reference case, deepwater discoveries of oil and natural gas resources in the Gulf of Mexico lead offshore production in the Lower 48 states to reach a record 2.4 million b/d in 2026. Many of these discoveries occurred during exploration that took place before 2015, when oil prices were higher than $100 per barrel, and they are being developed as oil prices rise. Offshore production increases through 2035 before generally declining through 2050 as a result of new discoveries only partially offsetting declines in legacy fields.

- Alaska crude oil production generally increases through 2041, driven primarily by the development of fields in the National Petroleum Reserve–Alaska (NPR-A) before 2030, and after 2030, by the development of fields in the 1002 Section of the Arctic National Wildlife Refuge (ANWR). Exploration and development of fields in ANWR is not economical in the Low Oil Price case.

The Southwest region leads onshore crude oil production in the United States in the AEO2020 Reference case

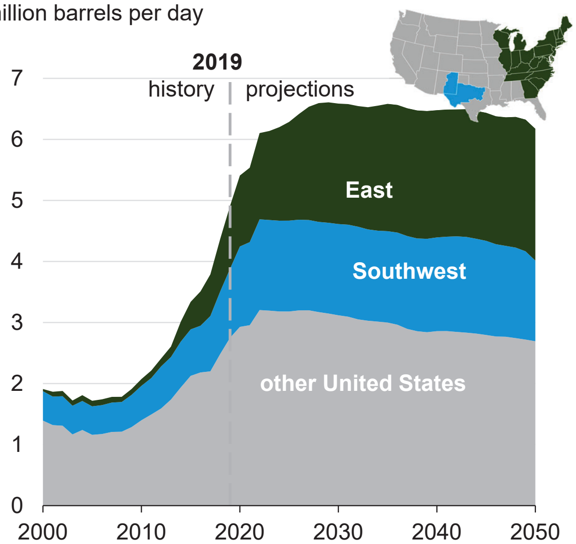
Onshore crude oil production in the Lower 48 states (AEO2020 Reference case)
million barrels per day



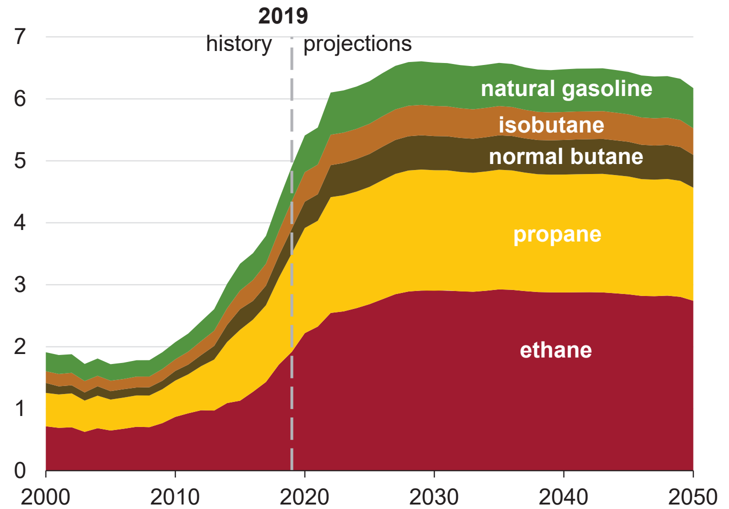


The East and Southwest regions lead production of natural gas plant liquids in the AEO2020 Reference case—

U.S. natural gas plant liquids production by region (Reference case)
million barrels per day



U.S. natural gas plant liquids production by type (Reference case)
million barrels per day



—as development focuses on tight plays with low production costs and easy access to markets

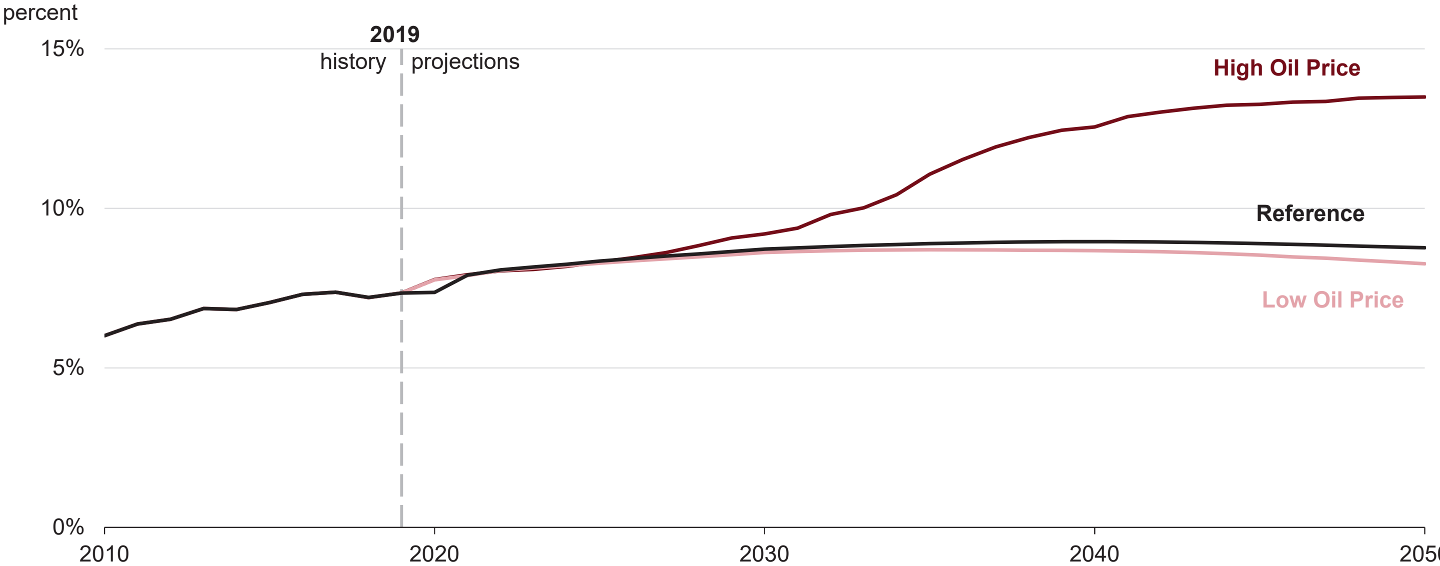
- NGPL production in the AEO2020 Reference case increases during the next 10 years in the East (Marcellus and Utica plays) and Southwest (Permian plays) regions because the development of crude oil and natural gas resources is driven in part by the increased economic favorability of coproducing these products. By 2050, the Southwest and East regions account for nearly 60% of total U.S. NGPL production.

- NGPLs are used in many different ways in the United States. Ethane is used almost exclusively for petrochemicals. About 40% of propane is used for petrochemicals, and the remainder is used for heating, grain drying, and transportation. About 60% of butanes and natural gasoline is used for blending with motor gasoline and fuel ethanol, and the remainder is used for petrochemicals and solvents.

- The shares of NGPL components in the AEO2020 Reference case are relatively stable during the entire projection period. Ethane and propane contribute about 44% and 30%, respectively, to the total volume.

Biofuels as a percentage of gasoline, diesel, and jet fuel consumption increase in the AEO2020 Reference case projection—

AEO2020 projected biofuel percentage of gasoline, distillate, and jet fuel consumption

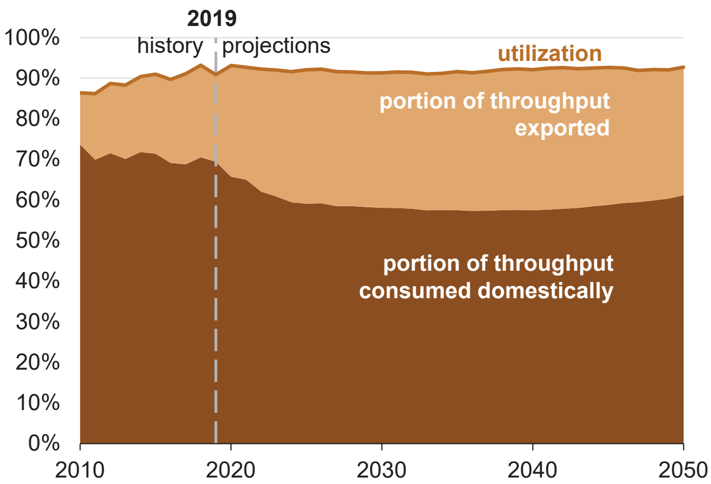


—and biofuels adoption accelerates in the AEO2020 High Oil Price case as biofuels become more competitive

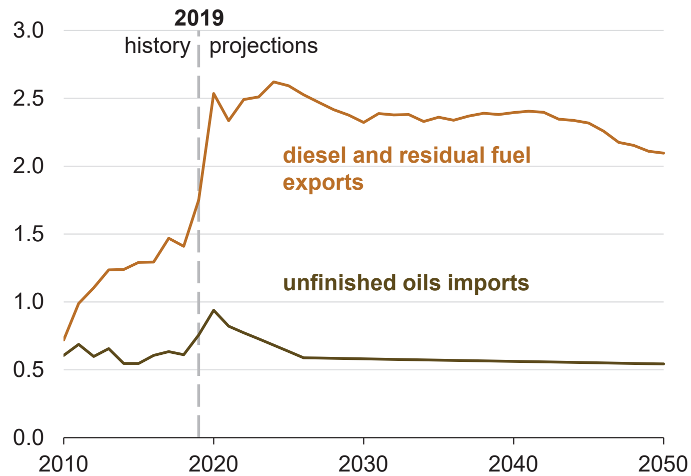
- EIA projects that the percentage of biofuels (ethanol, biodiesel, renewable diesel, and biobutanol) blended into U.S. gasoline, diesel, and jet fuel in the AEO2020 Reference case will increase from 7.3% in 2019 to peak at 9.0% in 2040.
- The share of biofuels consumed in the United States rises more in the AEO2020 High Oil Price case as higher prices for gasoline, diesel, and jet fuel make biofuels more competitive. In that case, the biofuels share rises to 13.5% in 2050.
- In the AEO2020 Low Oil Price case, the share of biofuels consumed in the United States is relatively unchanged compared with the Reference Case because of federal and state regulations. Regulations such as the Renewable Fuel Standard and Low Carbon Fuel Standard support biofuels consumption when prices of petroleum-based product are low and biofuels are less competitive.

Utilization of U.S. refineries remains near recent levels throughout the projection period in the Reference case as U.S. refineries remain competitive in the global market—

U.S. refinery utilization (Reference case)
percent



U.S. diesel and residual fuel exports and unfinished oils imports (Reference case)
million barrels per day



—and U.S. exports of low-sulfur diesel and residual fuel oil increase in 2020 as a result of international sulfur emissions regulations on the marine sector

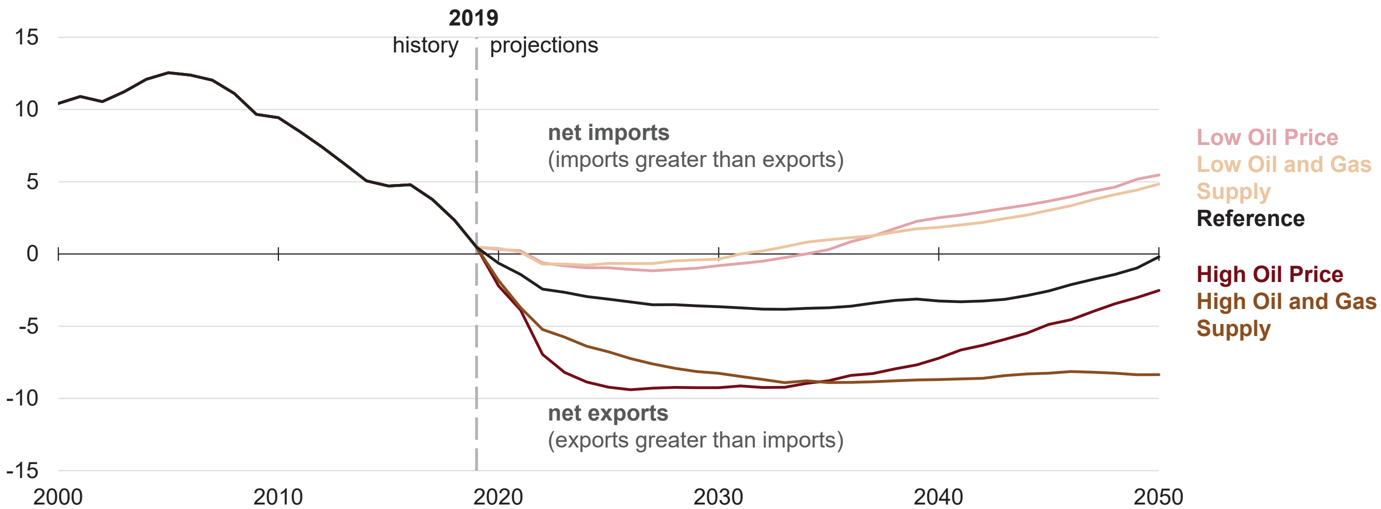
- The share of U.S. refinery throughput that is exported increases in the AEO2020 Reference case as domestic consumption of refined products decreases, leaving more petroleum product available to export from 2020 to 2041. The trend reverses after 2041 when domestic consumption (especially of gasoline) gradually increases.

- The global competitiveness of the U.S. refining sector and the ability of the United States to increase exports as domestic consumption falls keep domestic refinery utilization near recent levels, between 90% and 93%, during the projection period in the Reference case.

- Imports of unfinished oils peak in 2020 as U.S. refineries take advantage of the increased discount of the heavy, high-sulfur residual fuel oil available on the global market. Exports of diesel and residual fuel (especially low-sulfur residual fuel) increase to 2.5 million barrels per day in 2020 because U.S. refineries are well -positioned to supply some of the increase in global demand for low-sulfur fuels as a result of the International Maritime Organization's new limits on sulfur content in marine fuels.

In the AEO2020 Reference case, the United States exports more petroleum on a volume basis than it imports from 2020 to 2050—

AEO2020 U.S. petroleum and other liquids trade
million barrels per day



—but side case results vary significantly as shifts in U.S. domestic petroleum consumption and crude oil production drive changes to net imports

- In the AEO2020, strong production growth and decreasing domestic demand drive the United States to export higher volumes of crude oil and liquid fuels than it imports, resulting in growing levels of net exports from 2020 to 2033.

- In the AEO2020 Reference case, net exports of U.S. petroleum and other liquids peak at more than 3.8 million barrels per day (b/d) in the early 2030s before gradually declining as domestic consumption rises. The United States continues to export more petroleum and other liquids than it imports. Net exports of petroleum and other liquids reach 0.2 million b/d in 2050 as domestic consumption slowly increases but remains 1.2 million b/d below the peak levels recorded in 2004.

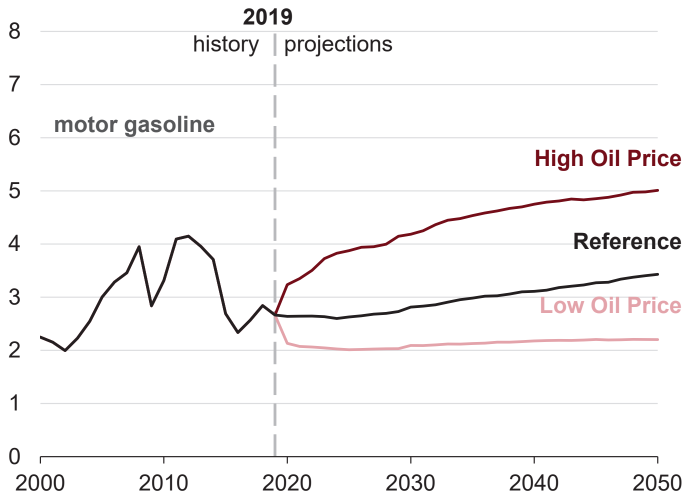
- Additional resources and higher levels of technological improvement in the AEO2020 High Oil and Gas Supply case result in more U.S. crude oil production and exports; net exports reach a high of 8.9 million b/d in the mid-2030s. Projected net exports reach a high of 9.6 million b/d in the mid-2020s in the High Oil Price case as a result of higher prices that support more domestic production.

- In the AEO2020 Low Oil Price case, by the mid-2020s, the United States exports 1.1 million b/d more than it imports before rising consumption leads the United States to become a net importer, importing 5.5 million b/d more than it exports in 2050.

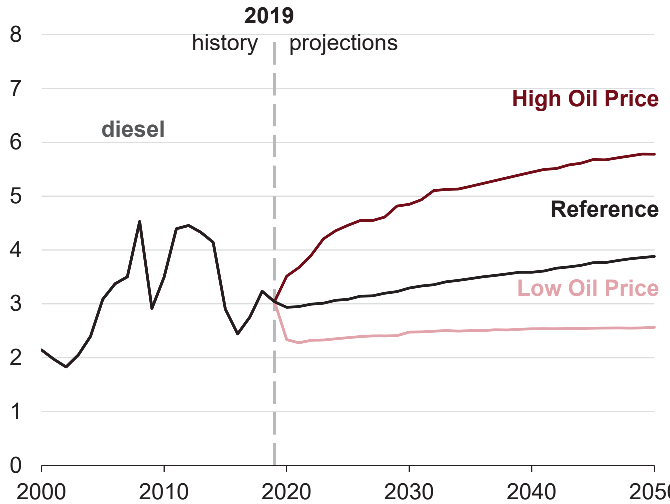
- All AEO2020 cases except the Low Oil and Gas Supply and Low Oil Price cases project that the United States will export more petroleum and other liquids than it imports through 2050.

Prices for gasoline and diesel fuel rise throughout the Reference case projection period and primarily follow the price of crude oil in the High Oil Price and Low Oil Price cases

AEO2020 retail prices of motor gasoline
2019 dollars per gallon



AEO2020 retail prices of diesel
2019 dollars per gallon

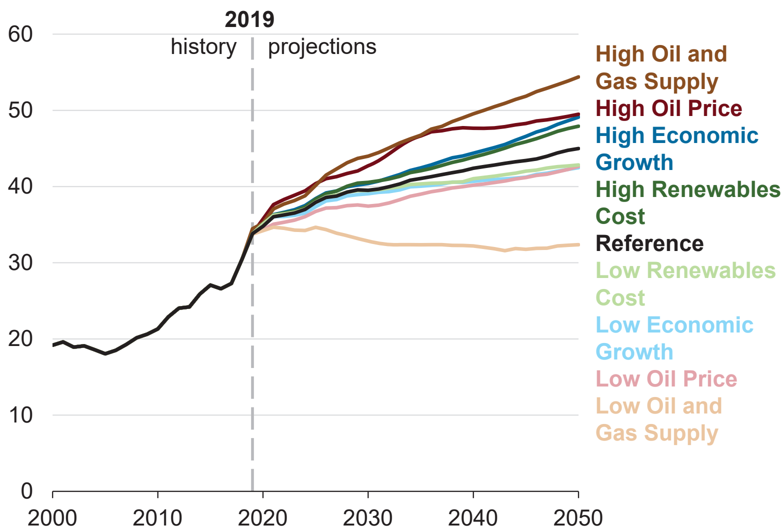


Natural gas

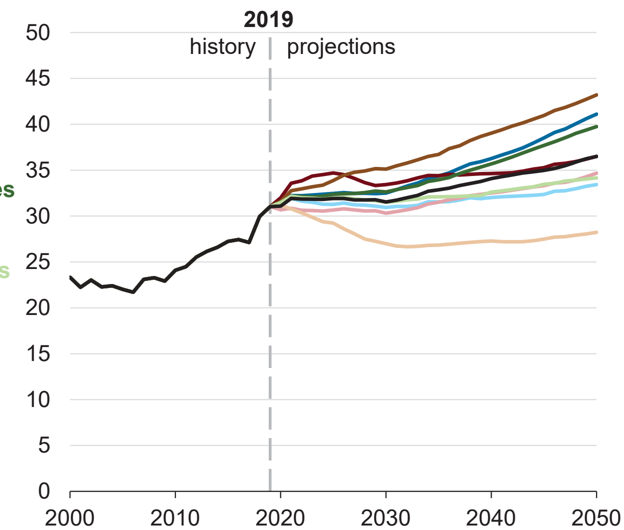
Natural gas production increases in most cases, supporting higher levels of domestic consumption and natural gas exports. However, AEO2020 projections are sensitive to resource and technology assumptions.

U.S. dry natural gas production and consumption increase in most AEO2020 cases—

AEO2020 U.S. dry natural gas production
trillion cubic feet



AEO2020 U.S. natural gas consumption
trillion cubic feet

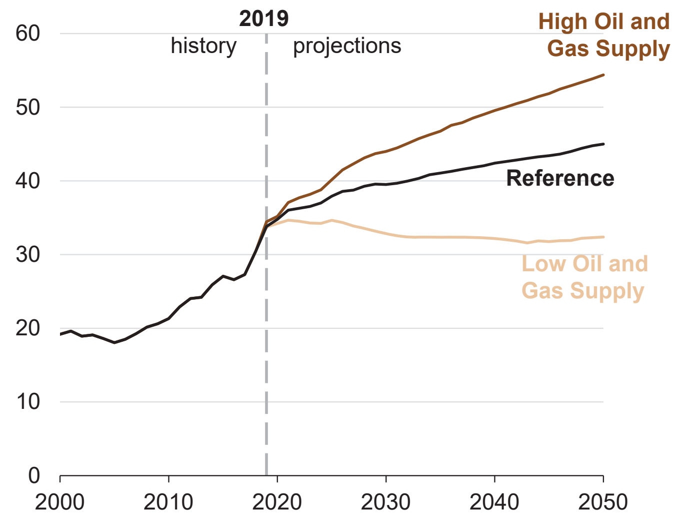


—and natural gas production growth outpaces consumption in most cases

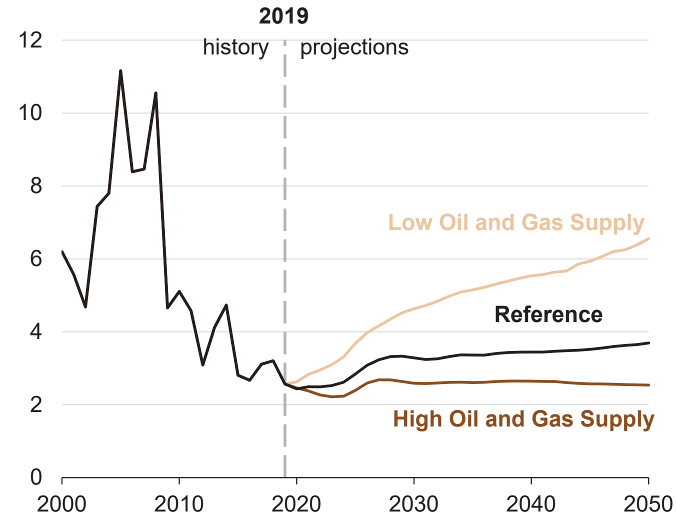
- Natural gas dry production in the AEO2020 Reference case grows 1.9% per year from 2020 to 2025, which is considerably slower than the 5.1%-per-year average growth rate from 2015 to 2020.
- U.S. natural gas consumption in the Reference case slows after 2020 and remains relatively flat through 2030 because of slower industrial sector growth. Consumption also declines in the electric power sector during this period. After 2030, consumption growth rises almost 1% per year on average as natural gas use in the electric power and industrial sectors increases.
- U.S. natural gas production grows at a faster rate than consumption in most cases after 2020, leading to an increase in U.S. exports of natural gas. The exception is in the AEO2020 Low Oil and Gas Supply case, where production and consumption remain relatively flat as a result of higher production costs.

AEO2020 natural gas prices depend on resource and technology assumptions—

AEO2020 dry natural gas production
trillion cubic feet



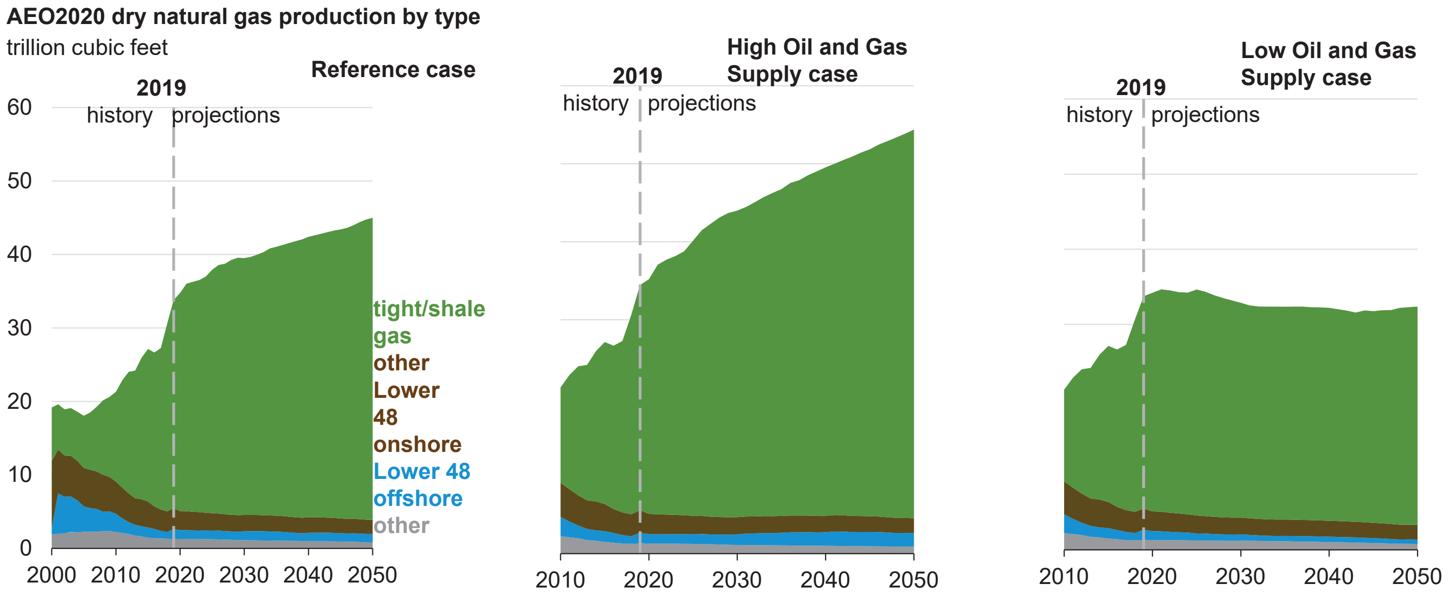
AEO2020 natural gas spot price at Henry Hub
2019 dollars per million British thermal units



—and Henry Hub prices in the AEO2020 Reference case remain lower than $4 per million British thermal units throughout the projection period

- In the AEO2020 Reference case, growing demand in domestic and export markets leads to increasing natural gas spot prices at the U.S. benchmark Henry Hub through 2050 despite continued technological advances that support increased production.
- To satisfy the growing demand for natural gas, U.S. natural gas production expands into less prolific and more expensive-to-produce areas, putting upward pressure on production costs.
- Natural gas prices in the AEO2020 Reference case remain lower than $4 per million British thermal units (MMBtu) through 2050 because of an abundance of lower cost resources, primarily in tight oil plays in the Permian Basin. These lower cost resources allow higher production levels at lower prices during the projection period.
- The AEO2020 High Oil and Gas Supply case--which reflects lower finding, development, and production costs and greater resource availability--shows an increase in U.S. natural gas production and lower prices relative to the Reference case. In the Low Oil and Gas Supply case, high prices, which result from higher costs and fewer available resources, result in less domestic consumption and exports during the projection period.

U.S. dry natural gas production in AEO2020 increases as a result of continued development of tight and shale resources—



—which account for more than 90% of dry natural gas production in 2050 in the Reference case

- Natural gas production from shale gas and tight oil plays continues to grow, both as a share of total U.S. natural gas production and in absolute volume, in the AEO2020 Reference case. This growth is a result of the size of the associated resources, which extend over nearly 500,000 square miles, and improvements in technology that allow development of these resources at lower costs.

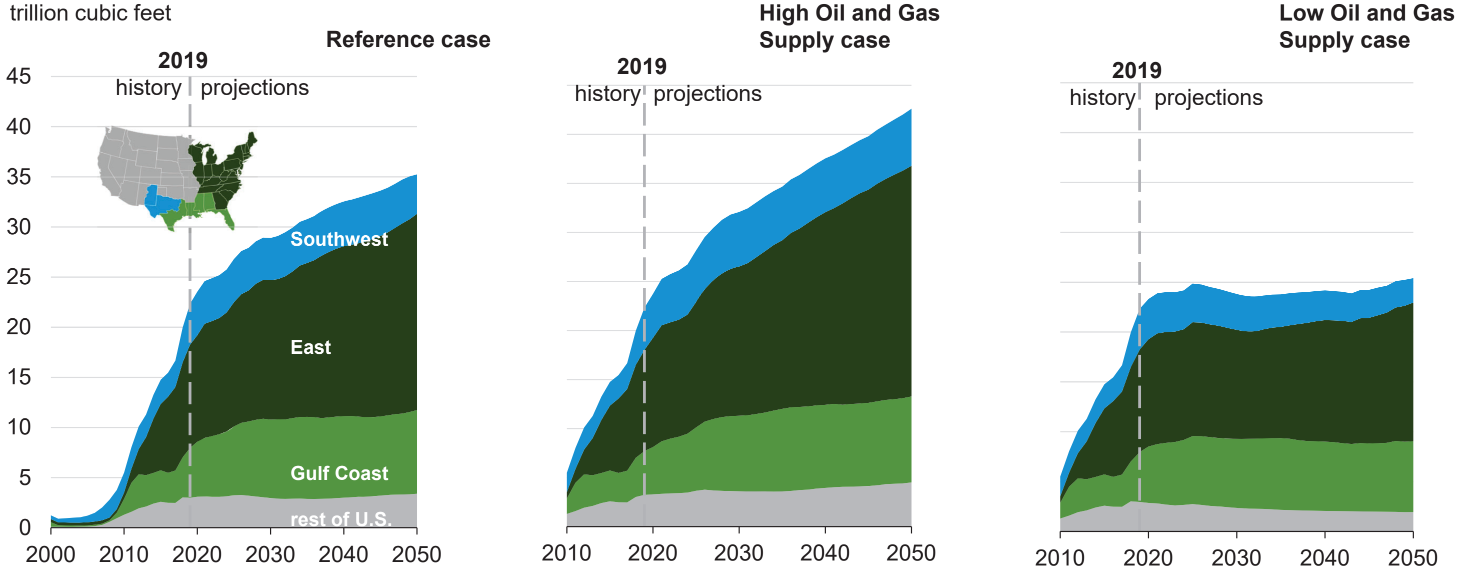
- In the High Oil and Gas Supply case, which has more optimistic assumptions regarding resource size and recovery rates, cumulative production from shale gas and tight oil is 14% higher than in the Reference case. Conversely, in the Low Oil and Gas Supply case, cumulative production from those resources is 20% lower than in the Reference case.

- Across all AEO2020 cases, onshore production of natural gas from sources other than tight oil and shale gas, such as coalbed methane, generally continues to decline through 2050 because of unfavorable economic conditions for producing these resources.

- Offshore natural gas production in the United States remains relatively flat during the projection period in all cases, driven by production from new discoveries that generally offsets declines in legacy fields.

Eastern U.S. production of natural gas from shale resources leads growth in the AEO2020 Reference case—

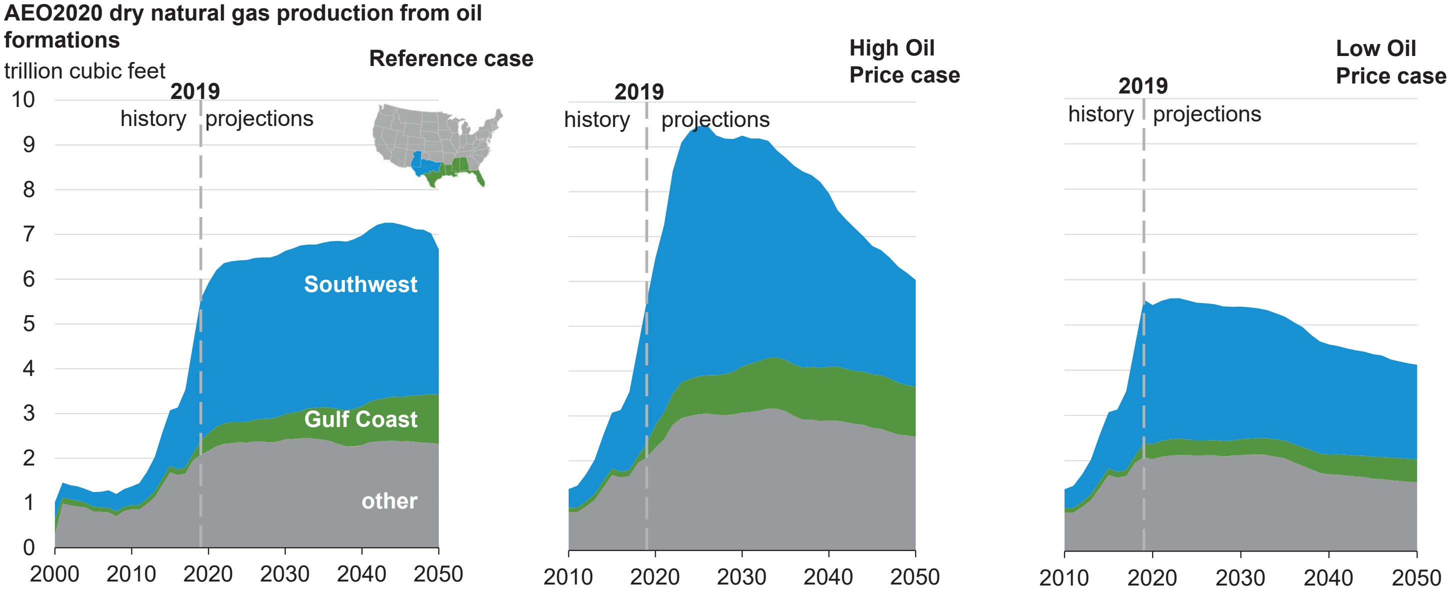
AEO2020 dry shale gas production by region
trillion cubic feet



—followed by growth in Gulf Coast onshore production

- Total U.S. natural gas production across most AEO2020 cases is driven by the continued development of the Marcellus and Utica shale plays in the East.
- Natural gas from the Eagle Ford (coproduced with oil) and the Haynesville plays in the Gulf Coast region also materially contributes to domestic dry natural gas production.
- Natural gas production associated with tight oil in the Permian Basin in the Southwest region greatly increases until 2022 but remains relatively flat afterwards to 2050.
- Technological advancements and improvements in industry practices lower production costs in the Reference case and increase the volume of oil and natural gas recovery per well. These advancements have a significant cumulative effect in plays that extend over wide areas and that have large undeveloped resources (for example, Marcellus, Utica, and Haynesville).
- Natural gas production from regions with shale and tight resources shows higher levels of variability across the AEO2020 supply side cases compared with the Reference case because assumptions in those cases target those resources.

The United States continues to produce large volumes of natural gas from oil formations—

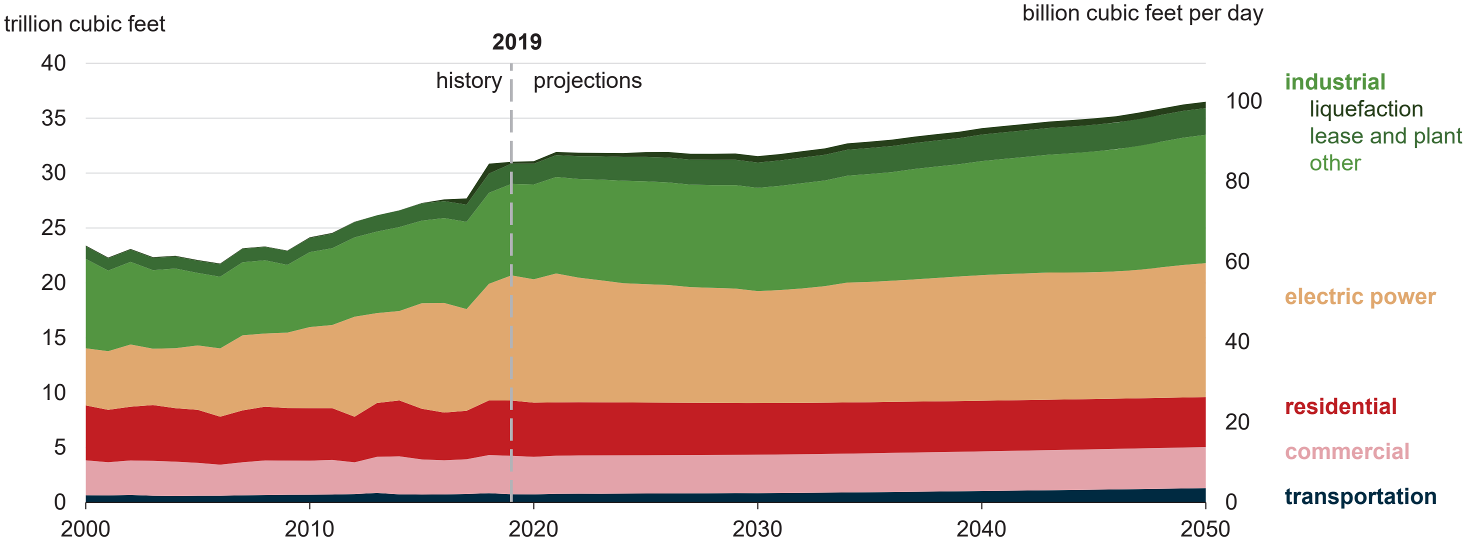


—even though relatively low oil prices put downward pressure on natural gas prices

- The percentage of dry natural gas production from oil formations in the United States increased from 8% in 2013 to 15% in 2018 and remains near this percentage through 2050 in the AEO2020 Reference case.
- Increased drilling in the Southwest, particularly in the Wolfcamp formation in the Permian Basin, is the main driver of growth in natural gas production from tight oil formations.
- The AEO2020 Low Oil Price case (which reflects a U.S. crude oil benchmark West Texas Intermediate price at $56 per barrel or lower) is the only case in which U.S. natural gas production from oil formations is lower in 2050 than current levels.
- The level of drilling in oil formations primarily depends on crude oil prices rather than natural gas prices. Increased natural gas production from oil-directed drilling puts downward pressure on natural gas prices throughout the projection period.

Industrial and electric power demand drives U.S. natural gas consumption growth—

Natural gas consumption by sector (AEO2020 Reference case)



—but consumption in the residential and commercial sectors remains relatively flat across the projection period in the AEO2020 Reference case

- Relatively low U.S. natural gas prices in the AEO2020 Reference case lead to continued growth in natural gas consumption in the near term, particularly in the electric power sector. However, through 2050, only the industrial sector shows markedly increased natural gas consumption.

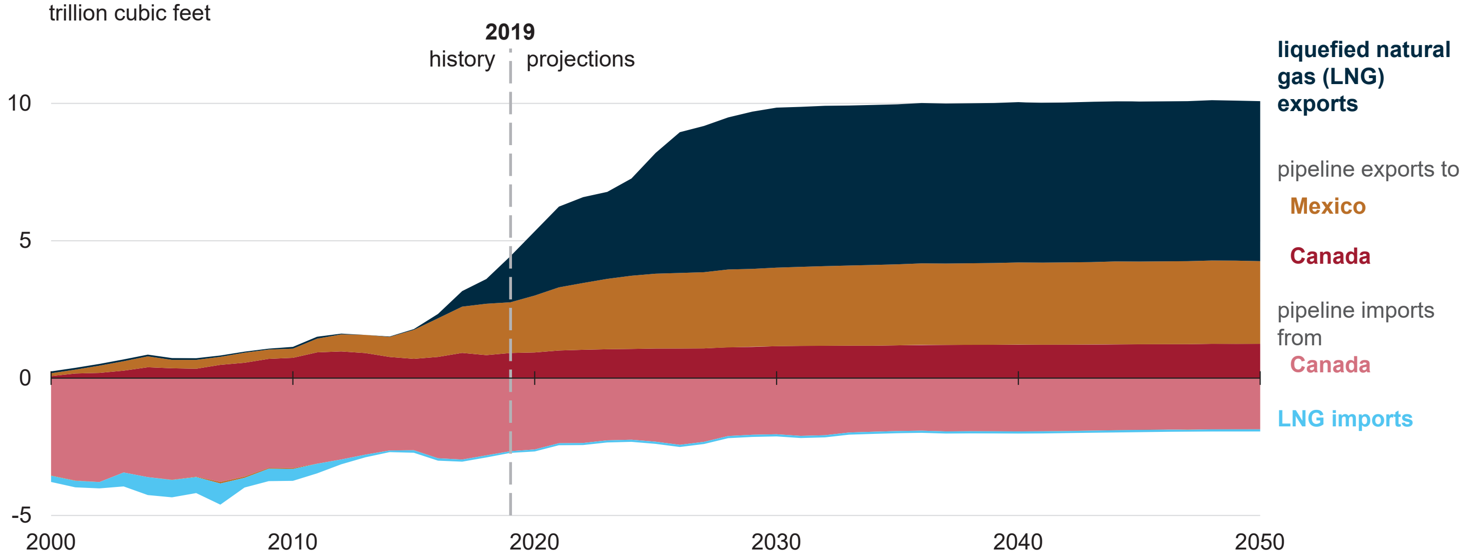
- The industrial sector, which includes fuel used for liquefaction at export facilities and in lease and plant operations, consumes more natural gas than any other sector in the United States after 2021. Major natural gas consumers in this sector include the chemical industry (where natural gas is used as a feedstock to produce methanol and ammonia), manufacturing heat and power, and lease and plant fuel.

- Natural gas used for U.S. electric power generation peaks in 2021 as relatively low natural gas prices, new natural gas-fired combined-cycle capacity, and coal-fired capacity retirements drive increases in natural gas-fired generation in the short term. However, strong growth in renewables and efficiency improvements in the remaining coal-fired fleet lead to declining amounts of natural gas consumed in the electric power sector through 2030. Natural gas consumption then slowly rises to reach its 2021 level again in the late 2040s.

- Natural gas consumption in the residential and commercial sectors remains largely flat because of efficiency gains and population shifts to warmer regions that counterbalance population growth. Although natural gas consumption rises in the transportation sector--particularly for freight trucks, rail, and marine shipping--it remains a small share of both transportation fuel demand and total natural gas consumption.

The United States continues to export more natural gas than it imports in the AEO2020 Reference case—

Natural gas trade (AEO2020 Reference case)
trillion cubic feet



—because near-term growth in liquefied natural gas export capacity delivers domestic production to global markets

- In the AEO2020 Reference case, pipeline exports to Mexico and liquefied natural gas (LNG) exports to world markets increase moderately until 2025, after which pipeline export growth to Mexico slows. LNG exports continue to rise through 2030 before remaining relatively flat for the remainder of the projection period.

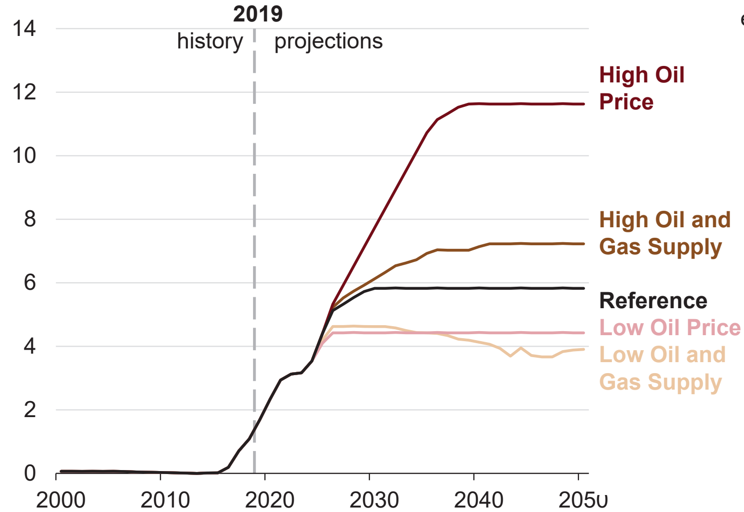
- Increasing natural gas exports to Mexico are a result of more pipeline infrastructure to and within Mexico, allowing for increased natural gas-fired power generation. By 2030, Mexico's domestic natural gas production begins to displace U.S. exports.

- Three more LNG-export facilities became operational in the Lower 48 states in 2019, bringing the total number to six. Two new LNG projects reached final investment decisions and started construction in 2019. All LNG-export facilities and expansions currently under construction are expected to be completed by 2025. U.S. LNG-export capacity will continue to serve growing global LNG demand, particularly in emerging Asian markets as long as U.S. natural gas prices remain competitive. As U.S.-sourced LNG becomes less competitive in world markets after 2030, export volumes level off.

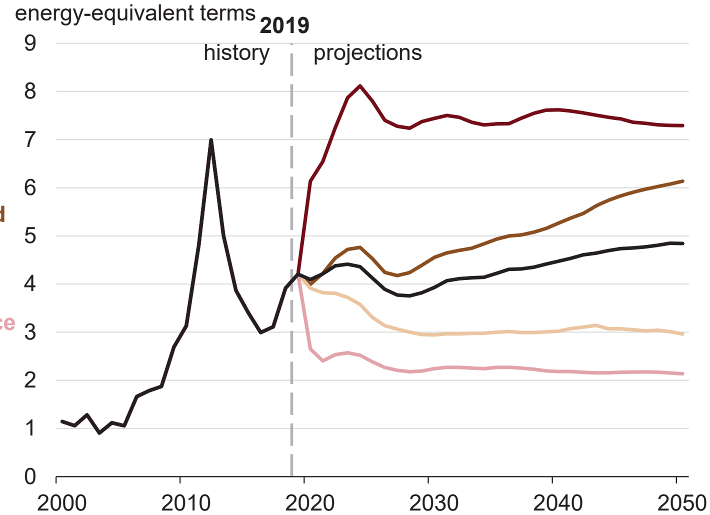
- U.S. imports of natural gas from Canada, primarily from its prolific western region, continue to generally decline from historical levels. U.S. exports of natural gas to eastern Canada continue to increase because of eastern Canada's proximity to U.S. natural gas resources in the Marcellus and Utica plays and new pipeline infrastructure. However, this export growth slows in the mid-2020s as Canada's demand for natural gas begins to decline, particularly in the electric power sector, as Canada begins transitioning to more renewables in its generation mix.

Liquefied natural gas (LNG) exports are sensitive to both oil and natural gas prices—

AEO2020 liquefied natural gas exports
trillion cubic feet



Ratio of Brent crude oil price to natural gas price at Henry Hub in AEO2020
energy-equivalent terms



—resulting in a wide range of U.S. LNG-export levels across cases

- Historically, most LNG was traded under long-term contracts linked to crude oil prices because the regional nature of natural gas markets prevented the development of a natural gas price index that could be used globally. In addition to providing a liquid global pricing benchmark, crude oil, to some degree, can act as a substitute for natural gas in industry and for power generation.

- As more natural gas is traded via short-term contracts or traded on the spot market, the link between LNG and oil prices weakens over time, making U.S. LNG exports less sensitive to the crude oil-to-natural gas price ratio and more responsive to the global LNG supply-natural gas demand dynamics. This shift causes growth in U.S. LNG exports to slow in all cases.

- When the crude oil-to-natural gas price ratio is highest, such as in the High Oil Price case, U.S. LNG exports are at their highest levels. U.S. LNG supplies are priced based on relatively low domestic spot prices instead of oil-linked contracts. In addition, demand for LNG increases, in part, as a result of consumers moving away from petroleum products.

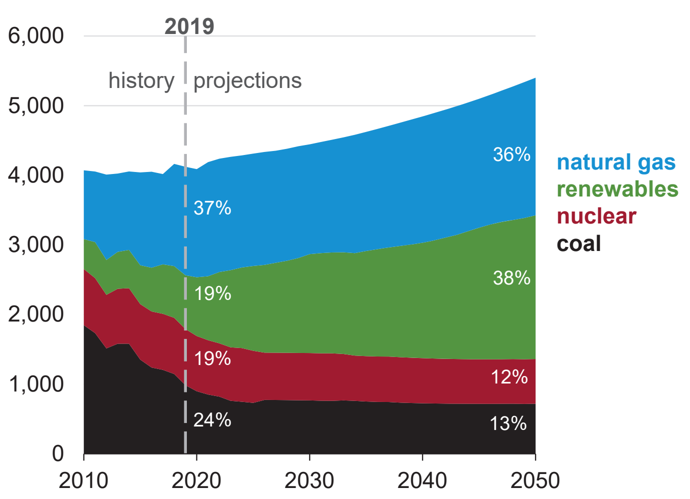
- In the High Oil and Gas Supply case, low U.S. natural gas prices make U.S. LNG exports competitive relative to other suppliers. Conversely, higher U.S. natural gas prices in the Low Oil and Gas Supply case result in lower U.S. LNG exports.

Electricity

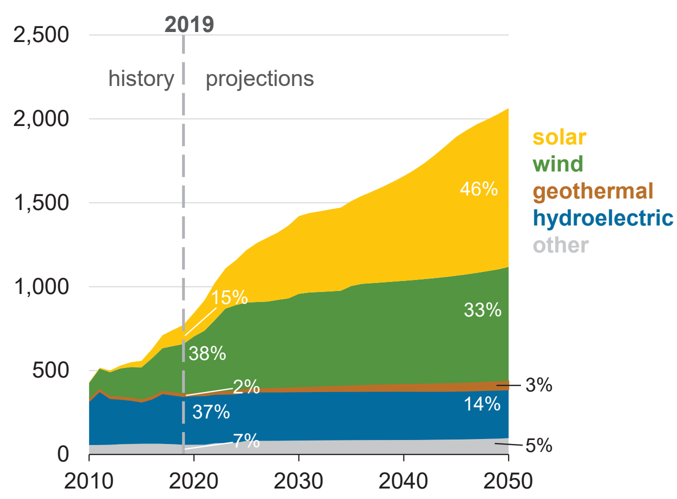
As electricity demand grows modestly, the primary drivers for new capacity in the AEO2020 Reference case are retirements of older, less-efficient fossil fuel units; the near-term availability of renewable energy tax credits; and the continued decline in the capital cost of renewables, especially solar photovoltaic. Low natural gas prices and favorable costs for renewables result in natural gas and renewables as the primary sources of new generation capacity through 2050. The future generation mix is sensitive to the price of natural gas and growth in electricity demand.

Electricity generation from natural gas and renewables increases as a result of lower natural gas prices and declining costs of solar and wind renewable capacity, making these fuels increasingly competitive

Electricity generation from selected fuels (AEO2020 Reference case)
billion kilowatthours

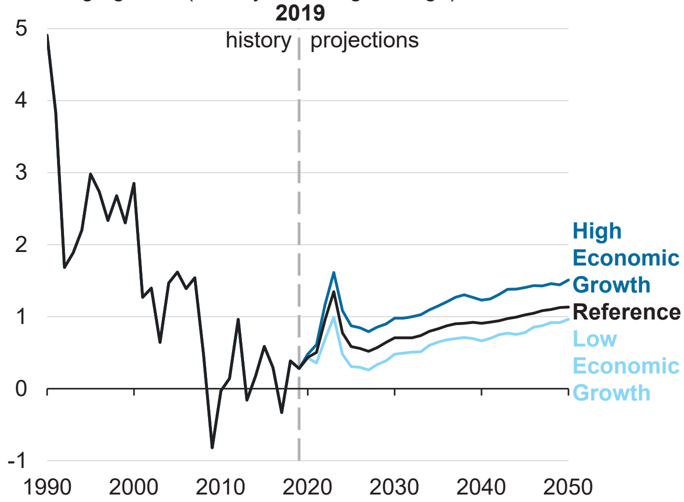


Renewable electricity generation, including end use (AEO2020 Reference case)
billion kilowatthours

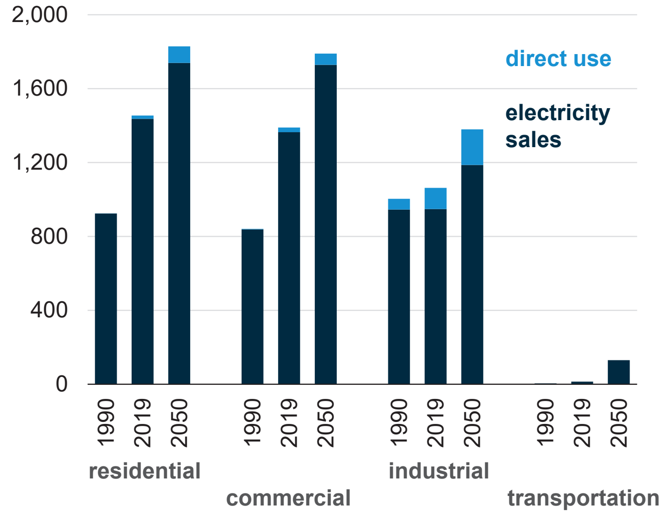


Electricity demand grows slowly through 2050 in the AEO2020 Reference case—

AEO2020 Electricity use growth rate
percentage growth (three-year rolling average)



Electricity use by end-use sector (AEO2020 Reference case)
billion kilowatthours

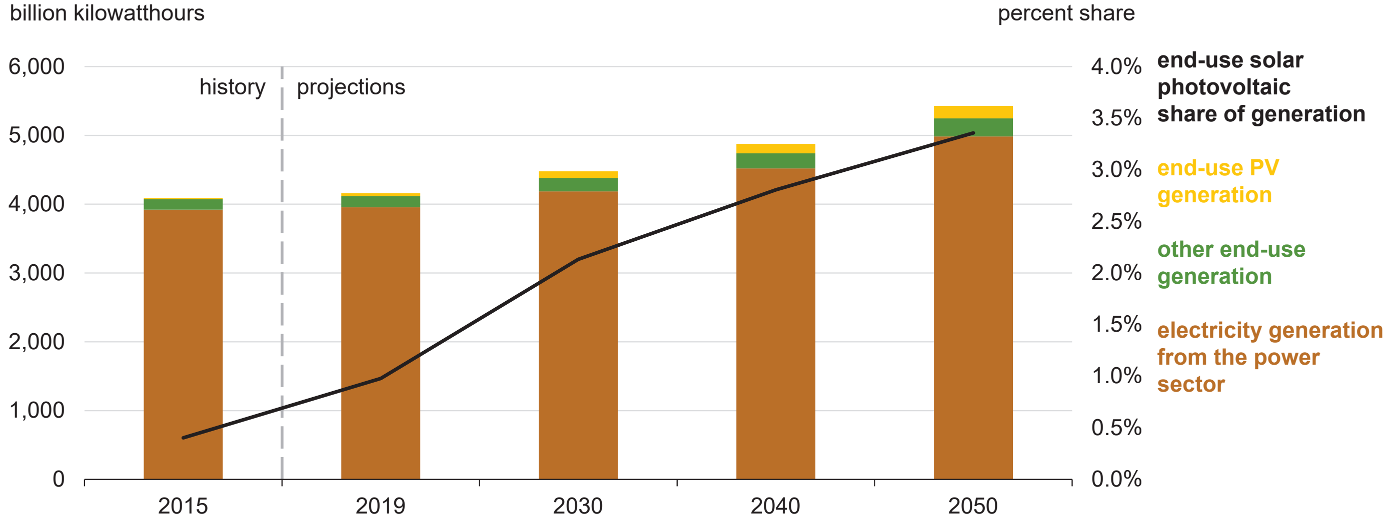


—with increases occurring across all end-use sectors

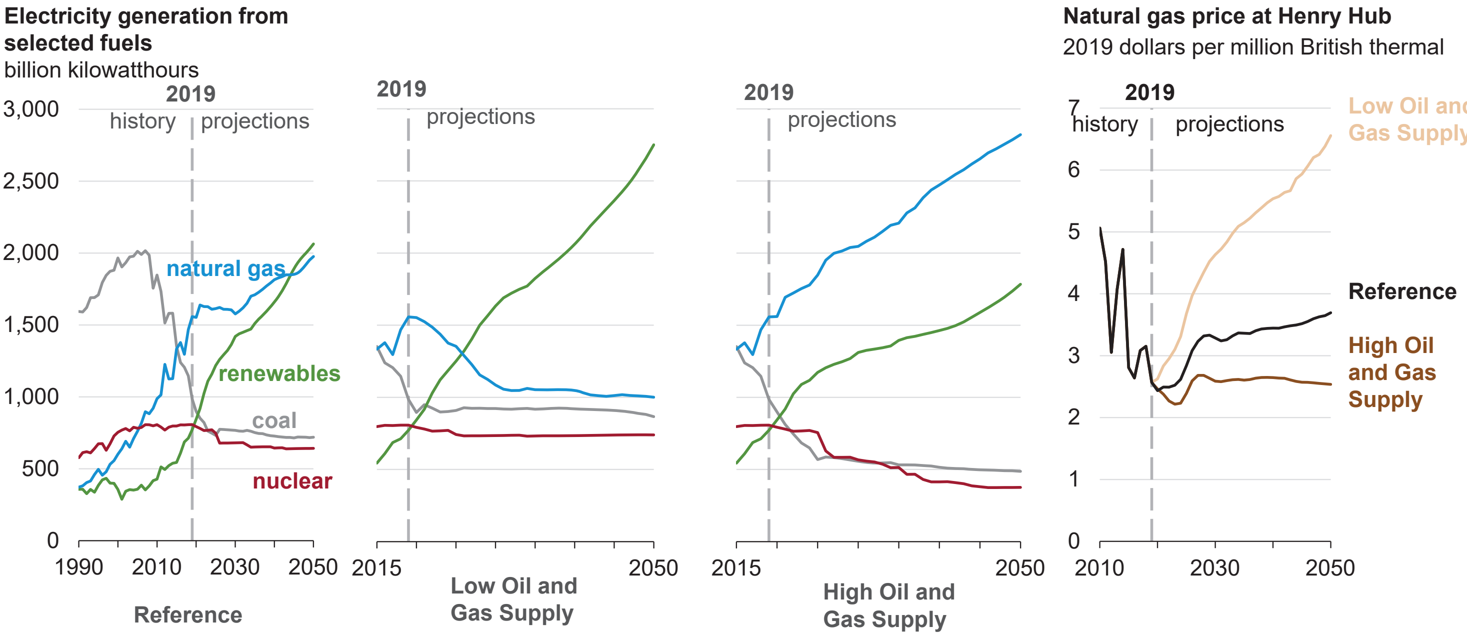
- Although near-term electricity demand may fluctuate as a result of year-to-year changes in weather, trends in long-term demand tend to be driven by economic growth offset by increases in energy efficiency. The annual growth in electricity demand averages about 1% throughout the projection period (2019-2050) in the AEO2020 Reference case.
- Historically, although the economy has continued to grow, growth rates for electricity demand have slowed as new, efficient devices and production processes that require less electricity have replaced older, less-efficient appliances, heating, ventilation, cooling units, and capital equipment.
- Average electricity growth rates in the AEO2020 High Economic Growth and Low Economic Growth cases vary the most from the Reference case. Electricity use in the High Economic Growth case grows 0.3 percentage points faster on average, and electricity use in the Low Economic Growth case grows 0.2 percentage points slower.
- The growth in projected electricity sales during the projection period would be higher if not for significant growth in generation from rooftop photovoltaic (PV) systems, primarily on residential and commercial buildings, and combined-heat-and-power systems in industrial and some commercial applications. By 2050, end-use solar photovoltaic accounts for 4% of U.S. generation in the AEO2020 Reference case.
- Electric power demand from the transportation sector is a very small percentage of economy-wide demand because electric vehicles (EVs) still represent a developing market. Given the lack of market evidence to date that would indicate a significant increase in U.S. consumer preference for EVs, EIA's AEO2020 projections reflect the dependence of the EV market on regulatory policies. Both vehicle sales and utilization (miles driven) would need to increase substantially for EVs to raise electric power demand growth rates by more than a fraction of a percentage per year.

An increasing share of total electricity demand is met with customer-owned generation, including rooftop solar photovoltaic

Electricity generation, end-use solar photovoltaic share (AEO2020 Reference case)



Declining costs for new wind and solar projects support the growing renewables share of the generation mix across a wide range of assumptions—

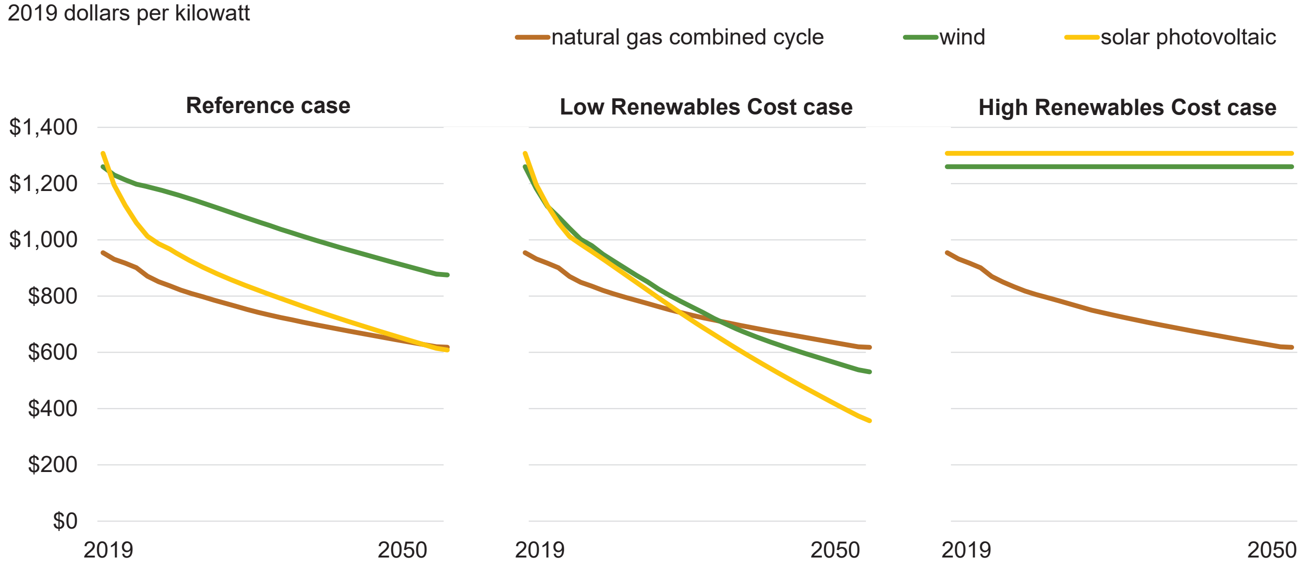


—although the results are sensitive to natural gas resource and price assumptions

- Because of declining capital costs and higher renewable portfolio standards (RPS) targets in some states, AEO2020 projects that the relatively sharp growth in renewables seen during the past 10 years will continue through the projection period. Total renewable generation exceeds natural gas-fired generation after 2045 in the AEO2020 Reference case. Renewable generation grows faster than overall electricity demand.
- Although coal-fired and nuclear generation decline through the mid-2020's as a result of retirements, generation from these sources stabilizes over the longer term as the more economically viable plants remain in service. At projected Reference case prices, natural gas-fired generation is the marginal fuel source to fulfill incremental demand and increases in the later projection years, averaging 0.8% growth per year through 2050.
- As a result of projected lower natural gas prices in the High Oil and Gas Supply case, natural gas-fired generation increases 1.9% per year through the projection period, reaching a 51% share of the generation mix by 2050. In contrast, under the projected higher natural gas prices in the Low Oil and Gas Supply case, natural gas-fired generation declines 1.4% per year through 2050, reaching a 19% share of the generation mix by 2050.

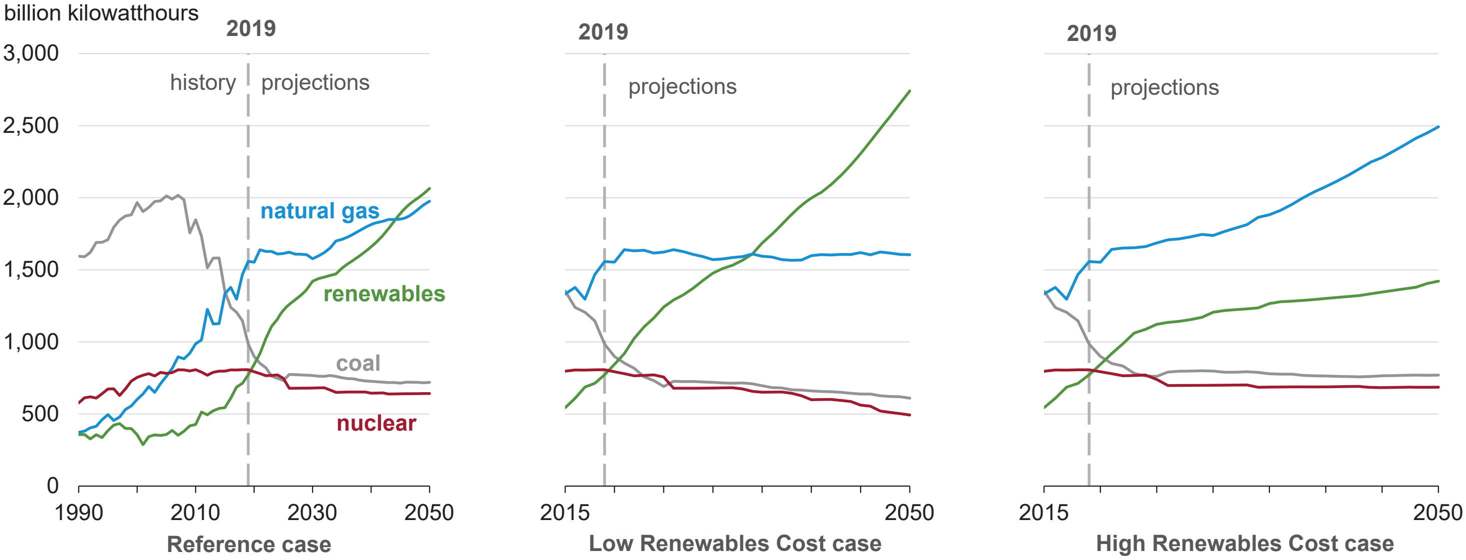
The High Renewables Cost and Low Renewables Cost cases assume different rates of cost reduction for renewable technologies compared with the Reference case; non-renewables assume the same rates

AEO2020 overnight installed cost by technology
2019 dollars per kilowatt



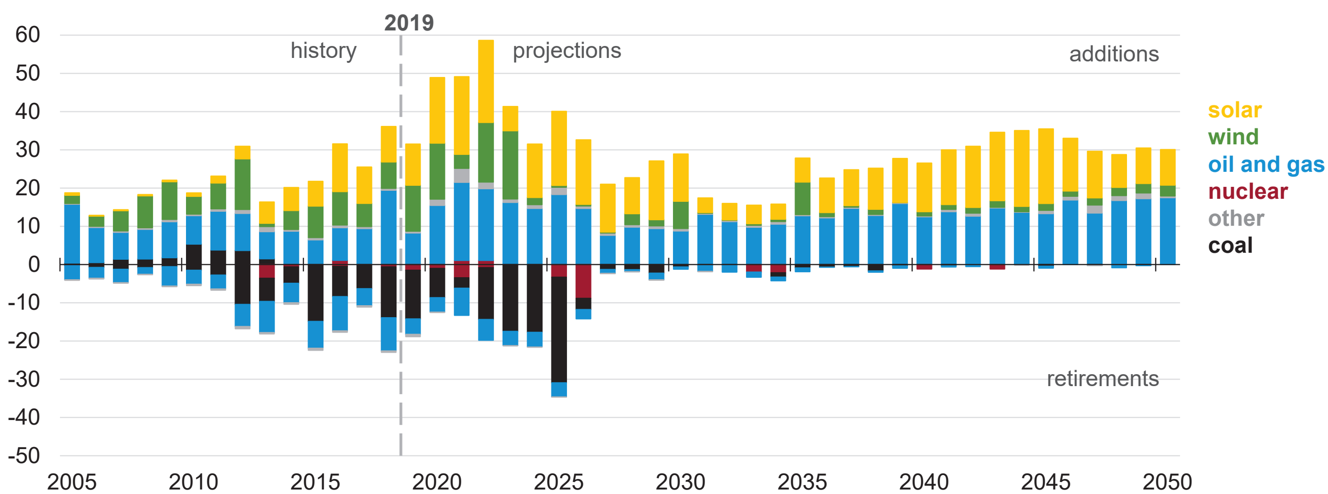
Changes in cost assumptions for new wind and solar projects result in significantly different projected fuel mixes for electricity generation

AEO2020 electricity generation from selected fuels
billion kilowatthours



Expected requirements for new generating capacity will be met by renewables and natural gas in the AEO2020 Reference case—

Annual electricity generating capacity additions and retirements (Reference case)
gigawatts



—as a result of competitive natural gas prices and declining costs for renewables

- In the AEO2020 Reference case, the United States adds 117 gigawatts (GW) of new wind and solar capacity between 2020 and 2023, which is the result of tax credits, increasing RPS targets, and declining capital costs.

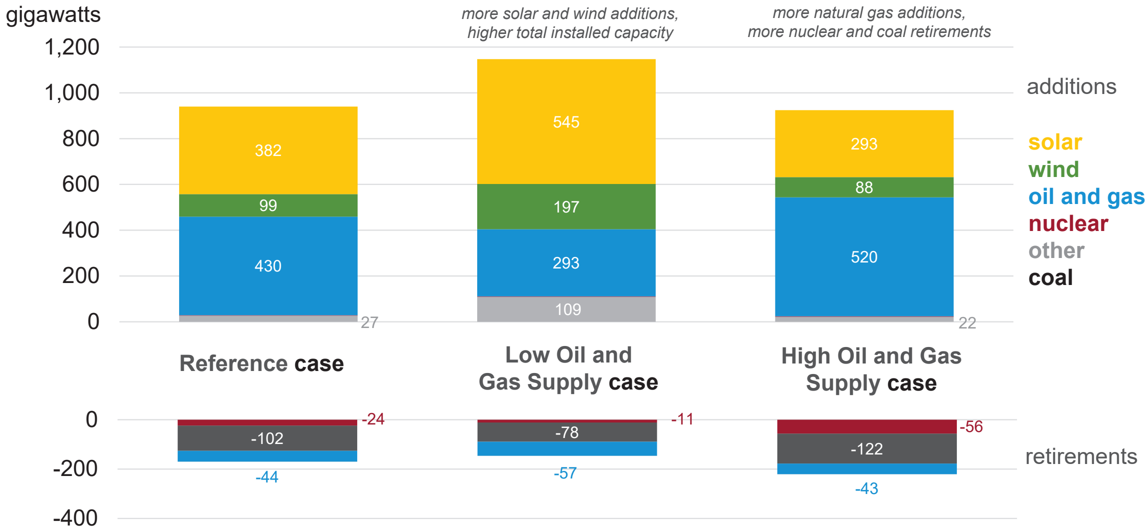
- New wind capacity additions continue at much lower levels after production tax credits expire in the early 2020s, but the growth in solar capacity continues through 2050 for both the utility-scale and small-scale applications because the cost of solar PV declines throughout the projection period.

- Natural gas-fired combined-cycle generation capacity is also added steadily throughout the projection period to meet rising demand.

- Most of the electric generation capacity retirements assumed in the AEO2020 Reference case occur by 2025. Although the final schedule will depend upon state-level implementation plans, in AEO2020 EIA assumes that coal-fired plants must either invest in heat rate improvement technologies by 2025 or retire to comply with the Affordable Clean Energy (ACE) rule. Heat rate improvement technologies increase the efficiency of power plants. The remaining coal plants are more efficient and continue to operate throughout the projection period. Low natural gas prices in the early years also contribute to the retirements of coal-fired and nuclear plants because both coal and nuclear generators are less profitable in these years.

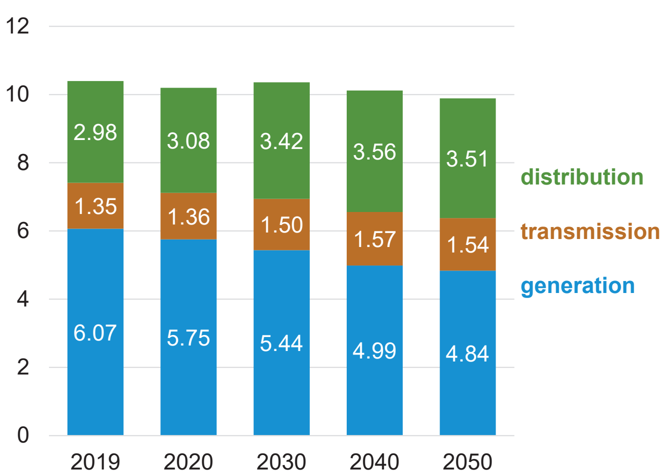
AEO2020’s long-term trends in electricity generation are dominated by solar and natural gas-fired capacity additions; coal, nuclear, and less efficient natural gas generators contribute to capacity retirements

AEO2020 cumulative electricity generating capacity additions and retirements (2020–2050)

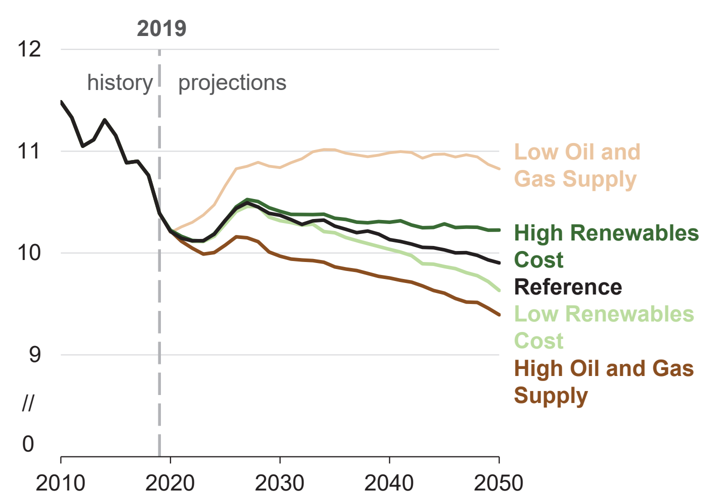


AEO2020 Reference case electricity prices fall slightly; declining generation costs are offset by rising transmission and distribution costs

Electricity prices by service category (AEO2020 Reference case)
2019 cents per kilowatthour

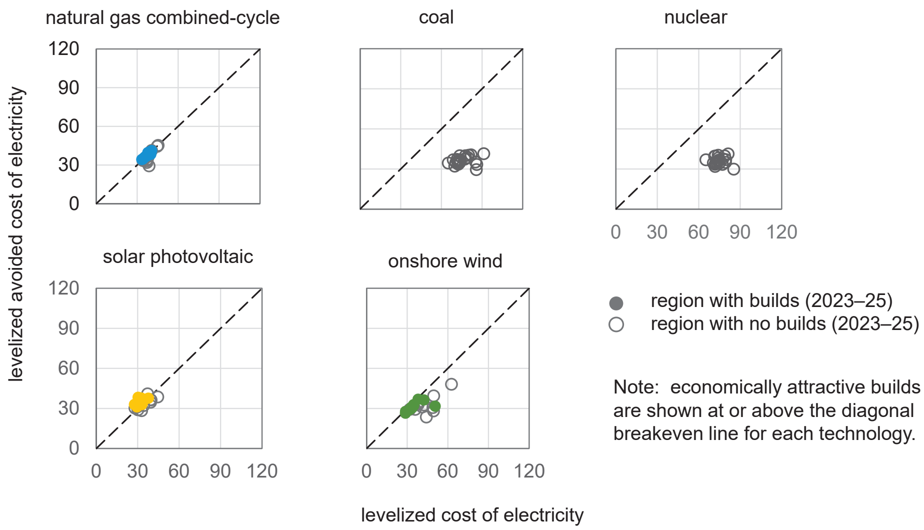


AEO2020 average electricity price
2019 cents per kilowatthour



In the AEO2020 Reference case, combined-cycle and solar photovoltaic are the most economically competitive generating technologies—

AEO2020 levelized cost of electricity and levelized avoided cost of electricity by technology and region, 2025
2019 dollars per megawatthour



—when considering the overall cost to build and operate and the value of the plant to the grid

- The levelized cost of electricity (LCOE) reflects the cost to build and operate a power plant per unit of generation, annualized over a cost recovery period. When compared with the levelized avoided cost of electricity (LACE), or expected average revenue realized by that plant, we can estimate the economic competitiveness for that generating technology.

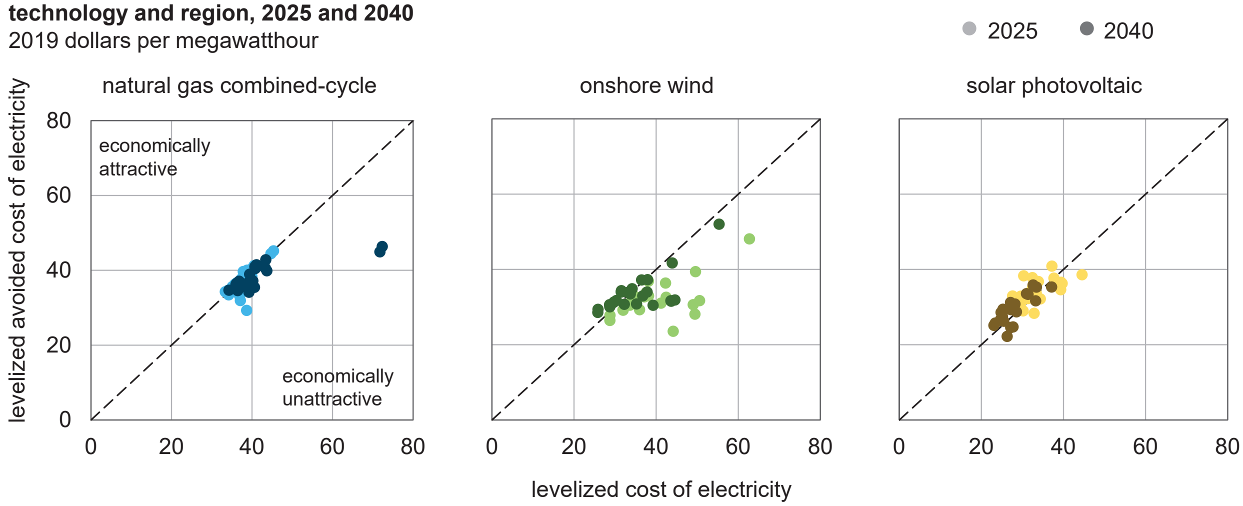
- The solid, colored circles on the figure indicate that projects tend to be built in regions where revenue (LACE) exceeds costs (LCOE). In the AEO2020 Reference case, expected revenues from electric generation for both natural gas-fired combined-cycle and solar photovoltaic with single axis tracking are generally greater than or equal to projected costs across the most electricity market regions in 2025. Correspondingly, these two technologies show the greatest projected growth through the middle of the 2030s.

- The value of wind approaches its cost in nearly half of the regions. These regions see new wind capacity builds in the AEO2020 Reference case, primarily in advance of the phase-out of the production tax credit (PTC), through the early part of the next decade.

- LACE accounts for both the variation in daily and seasonal electricity demand in the region where a new project is under consideration and the characteristics of the existing generation fleet where the new capacity will be added. The prospective new generation resource is compared with the mix of new and existing generation and capacity that it would displace. For example, a wind resource that would primarily displace existing natural gas-fired generation will usually have a different value than one that would displace existing coal-fired generation.

Onshore wind will become more competitive over time, while natural gas-fired combined-cycle and solar photovoltaic maintain their current competitive positions—

AEO2020 Reference case levelized cost of electricity (LCOE) and levelized avoided cost of electricity (LACE) by technology and region, 2025 and 2040
2019 dollars per megawatthour



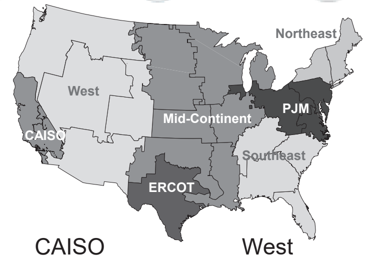
—as LCOE declines through learning-induced cost reductions and LACE increases with rising demand and natural gas prices

- Changes in AEO2020 electricity generation costs over time reflect a number of factors, sometimes working in different directions. For both solar photovoltaic (PV) and onshore wind, LCOE increases in the near term with the phase-out and expiration of the investment tax credit (ITC) and PTC, respectively. However, LCOE eventually declines over time because technological improvements tend to reduce LCOE through lower capital cost or improved performance (as measured by heat rate for natural gas combined-cycle plants or capacity factor for onshore wind or solar PV plants), partly offsetting the loss of the tax credits.

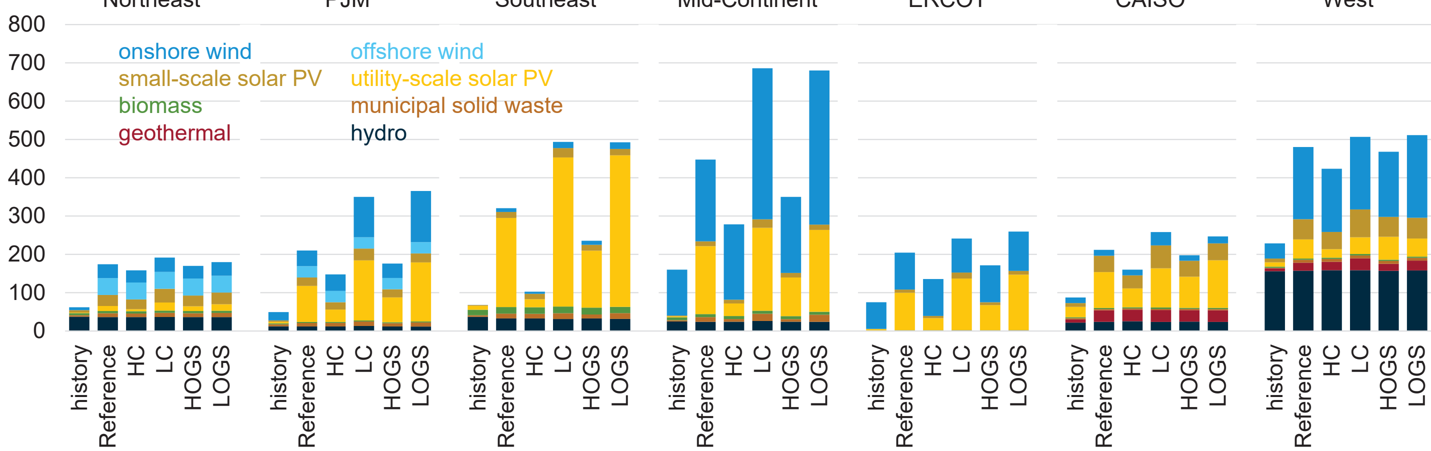
- Natural gas-fired combined-cycle plants with online years of 2025 and 2040 in the AEO2020 projection have similar LCOE because the technology has reached market maturity, judging from the build patterns throughout the projection years across all regions. The two outliers in the 2040 LCOE projection are attributed to the increase in variable operations and in maintenance costs for plants in California as a result of the state's phase-out of fossil fuel-fired generation starting in 2030.

- Solar may show strong daily generation patterns within any given region; therefore, AEO2020 LACE for solar PV declines over time as the market becomes saturated with generation from resources with similar hourly generation patterns. LACE for onshore wind is generally lower than other technologies because most of the generation at these plants occurs at night or during fall and spring seasons when the demand for and the value of electricity is typically lower. Solar PV plants produce most of their energy during the middle of the day when higher demand increases the value of electricity, resulting in higher LACE.

Solar and wind lead the growth in renewables generation in most regions across all cases in AEO2020



Total renewables generation (all sectors), 2018 and 2050
billion kilowatthours



Note: HC = High Renewables Cost, LC = Low Renewables Cost, HOGS = High Oil and Gas Supply, LOGS = Low Oil and Gas Supply, PV= photovoltaic

—but its penetration rate differs by regional resource and generation mix

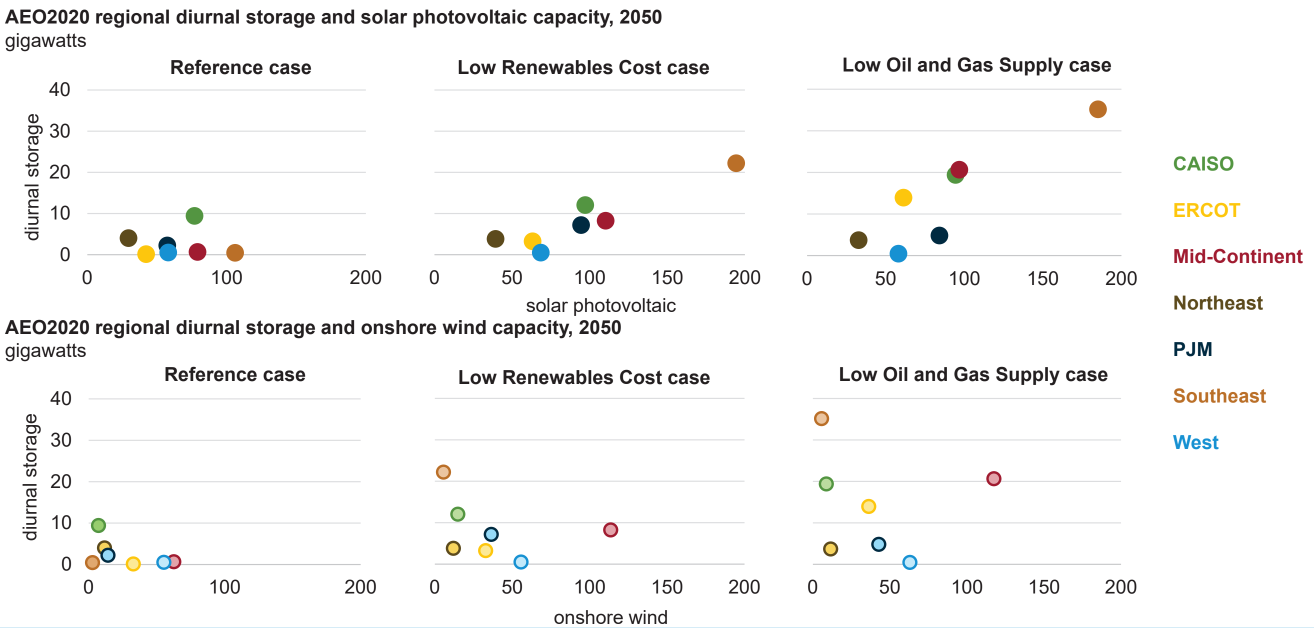
- The AEO2020 projects that generation from renewable sources will rise from 18% of total generation in 2018 to 38% by 2050 in the Reference case. Solar photovoltaic (PV) contributes the most to the growth in renewable generation, increasing from 13% of total renewable generation in 2018 to 46% by 2050. Although onshore wind generation more than doubles during the projection period, its share of renewable generation declines slightly from 37% to 29% between 2018 and 2050.

- Solar PV generation grows the most in Southeast and Mid-Continent regions in nearly all cases. On average, these two regions have higher-than-average delivered U.S. natural gas prices, making natural gas generation a more expensive option to replace retired coal or nuclear generation. Because solar PV generates mostly during daytime hours, it can readily substitute natural gas generation during periods of higher demand. Regions with existing wind capacity continue to install new wind capacity between 2018 and 2050.

- When natural gas prices are higher, as in the Low Oil and Gas Supply case, onshore wind becomes the incremental generation source in the Mid-Continent region, where wind resources are abundant. Wind generation for the region is 189 billion kilowatthours (BkWh) higher (89% increase) in 2050 than in the Reference case, and all-sector solar PV generation is 37 BkWh higher (20% increase).

- The Northeast, ERCOT (Electric Reliability Council of Texas), CAISO (California Independent System Operator), and West regions have relatively small variations in results across the alternative cases. The small variations are most likely a result of the regions' current small shares of existing coal generation capacity that may need to be replaced over the projection period. The share of renewables is also comparatively large in these regions.

Growth in utility-scale battery storage in AEO2020 follows growth in solar in most regions in high renewable penetration scenarios—



—but does not benefit from wind growth, which has more unpredictable generation patterns

- The AEO2020 Reference case projects that the United States will have 17 GW of battery storage capacity in 2050. Storage capacity takes advantage of times when an oversupply of electricity occurs, which generally happens in areas that have a high penetration of non-dispatchable renewable resources such as wind and solar. Limitations in the time a battery can store electricity make batteries more suitable for solar, which has more predictable generation patterns than wind.

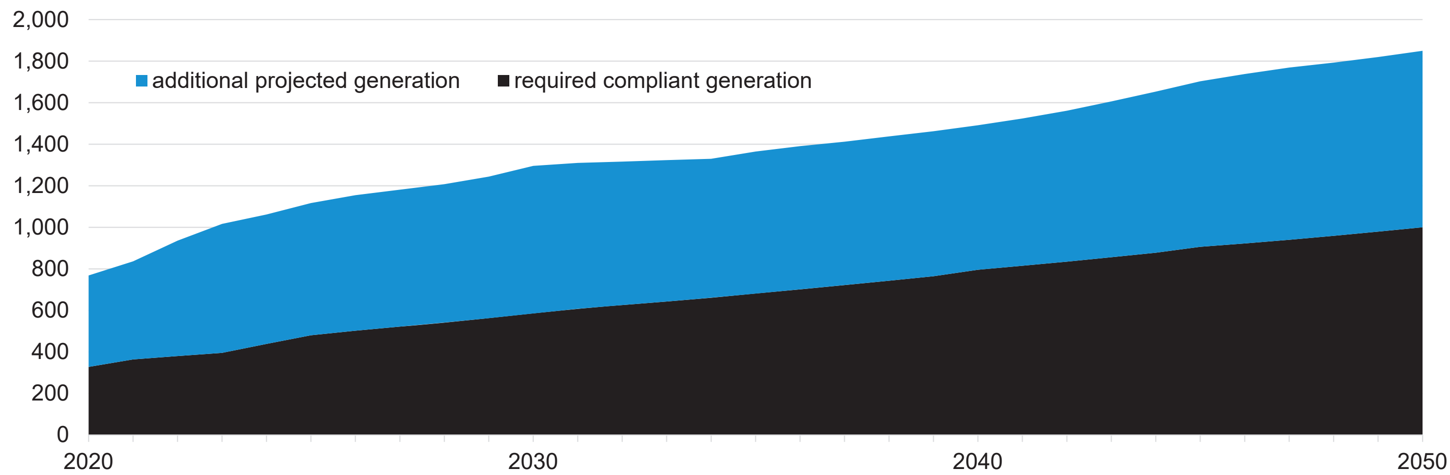
- The large number of combustion turbine (CT) additions in the West and Mid-Continent regions correspond the large number of wind additions in these regions. Because wind energy is less predictable and fluctuates in intensity for long periods, current limitations in the length of time a battery can store or generate power make batteries an inadequate backup for wind power. Therefore, CTs, which have no duration limit as long as natural gas fuel is available, fill the gap. CTs in the West region are also supported by its large hydropower resources.

- Storage growth is stronger in AEO2020 scenarios that have a high penetration of renewables, such as the Low Renewables Cost and Low Oil and Gas Supply cases. The Low Renewables Cost case projects 57 GW of storage by 2050, and the Low Oil and Gas Supply case projects 98 GW of storage by 2050.

- In both the Low Renewables Cost and Low Oil and Gas Supply cases, the Southeast and California regions see high amounts of solar capacity in 2050, minimal amounts of wind capacity, and concurrently large amounts of battery storage. The Northeast, the West, and the PJM regions have relatively low solar capacity and lower storage capacity.

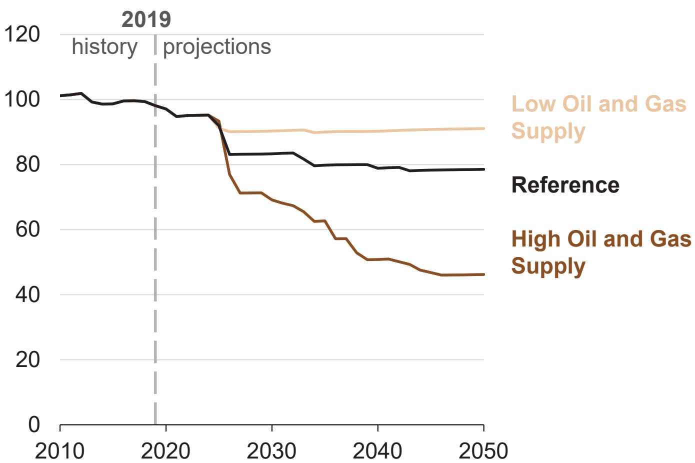
Even with recent increases in several states' renewable portfolio standards, renewable generation that exceeds requirements allows for full compliance in the AEO2020 Reference case by 2050

AEO2020 Reference case total qualifying renewables generation required for combined state renewable portfolio standards and projected total generation from compliant technologies, 2020–2050
billion kilowatthours

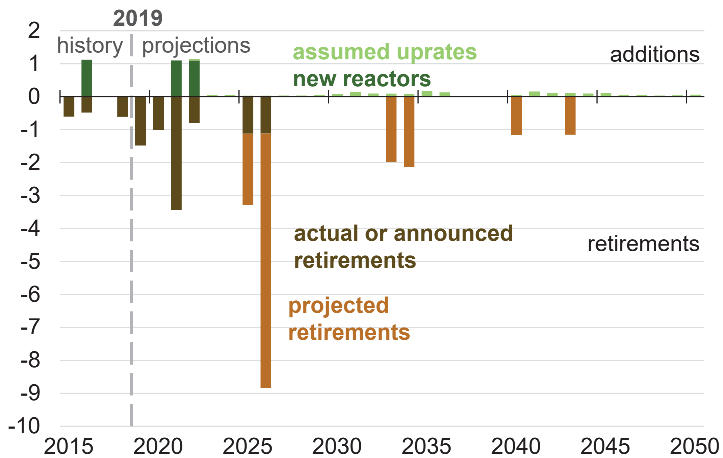


Lower natural gas prices throughout the AEO2020 projection period accelerate nuclear capacity retirements—

AEO2020 nuclear electricity generating capacity
gigawatts



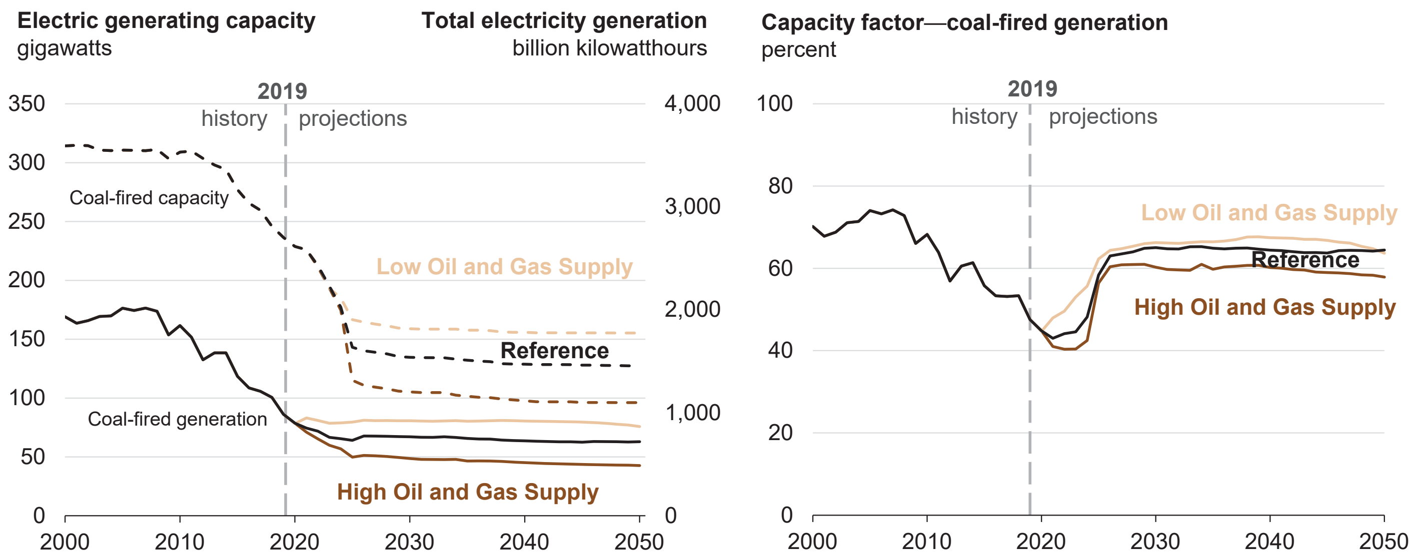
Year-over-year nuclear capacity changes (AEO2020 Reference case)
gigawatts



—as a result of declining revenue in competitive wholesale power markets

- The AEO2020 Reference case projects a 19% decline in nuclear electric generating capacity from 98 GW in 2019 to 79 GW in 2050. No new plant additions occur beyond 2022, and existing plants have 2 GW of uprates starting in 2022.
- Projected nuclear retirements are driven by declining revenues that result from low growth in electricity load and from increasing competition from low-cost natural gas and declining-cost renewables. Smaller, single-reactor nuclear plants with higher average operating costs are most affected, particularly those plants operating in regions with deregulated wholesale power markets and in states without a zero emission credit policy.
- Lower natural gas prices in the High Oil and Gas Supply case lead to lower wholesale power market revenues for nuclear power plant operators, accelerating an additional 32 GW of nuclear capacity retirements by 2050 compared with the Reference case.
- Higher natural gas prices in the Low Oil and Gas Supply case help increase profitability for nuclear power plant operators, resulting in 13 GW fewer retirements through 2050 compared with the Reference case.

Coal-fired generating capacity retires at a faster pace than total generation in the AEO2020 Reference case—



—as capacity factors increase for the more efficient coal-fired units that remain in service

- In addition to decreases as a result of competitively priced natural gas and increasing renewables generation, coal-fired generating capacity decreases by 109 GW (or 46%) between 2019 and 2025 to comply with the Affordable Clean Energy (ACE) rule before leveling off near 127 GW in the AEO2020 Reference case by 2050.

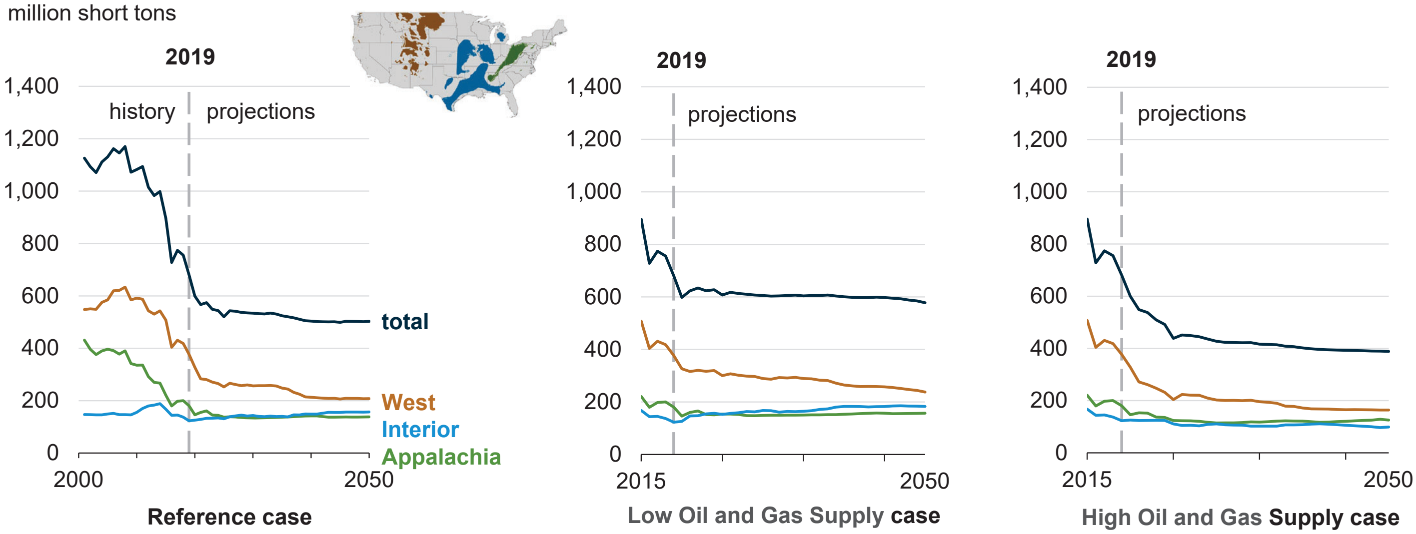
- Average capacity factors for coal-fired generating units improve over time as less-efficient units are retired, as heat rates in the remaining coal fleet improve to comply with the ACE rule, and as natural gas prices increase

- Between 2019 and 2025, coal-fired generation decreases by 26% in the Reference case while natural gas prices increase. By 2030, the utilization rate of the remaining coal-fired capacity returns to 65%, which is slightly less than in the early 2000s. In the High Oil and Gas Supply case, coal-fired generation decreases by 42% between 2019 and 2025, and lower natural gas prices limit the utilization rate of the coal fleet to about 60% in 2030.

- Higher natural gas prices in the Low Oil and Gas Supply case slow the pace of coal power plant retirements by about 23 GW through 2025 compared with the Reference case. The Low Oil and Gas Supply case has 155 GW of coal-fired capacity still in service in 2050. Conversely, lower natural gas prices in the High Oil and Gas Supply case increase coal-fired power plant retirements by 28 GW in 2025, and 96 GW of remaining coal-fired capacity remains by 2050.

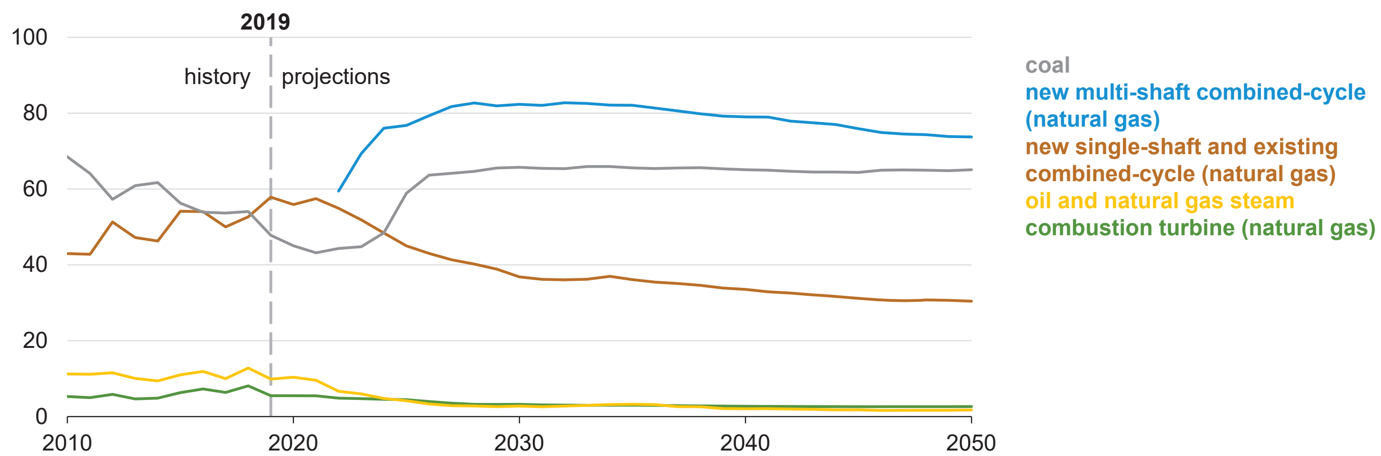
Coal production decreases through 2025 due to retiring coal-fired electric generating capacity, but federal rule compliance and higher natural gas prices lead to coal production leveling off afterwards

AEO2020 coal production by region
million short tons



Lower operating costs and higher efficiencies result in advanced natural gas-fired combined-cycle capacity factors of 80% by 2030 in the AEO2020 Reference case—

Capacity factor for fossil-fired plants (AEO2020 Reference case)
percent



—but then decline over time as natural gas prices increase and renewable generation grows

- Lower natural gas prices and reduced capital costs for new natural gas-fired combined-cycle generating units change fossil fuel electric generation use during the next decade in the AEO2020 Reference Case. Beginning in 2022—the first year of availability—new, multi-shaft (2 x 2 x 1 configuration) combined-cycle natural gas-fired units have the highest projected capacity factors of all technologies, averaging 81% between 2025 and 2035. The currently most common combined-cycle units, with their lower efficiency, and the new single-shaft (1 x 1 x 1 configuration) combined-cycle units decline in utilization as a group, from 56% in 2020 to 36% by 2035.

- After 2035, capacity factors for both combined-cycle technologies decline gradually, in part because large increases in intermittent generation through 2050 alter the dispatch patterns and requirements for fossil fuel-fired generation.

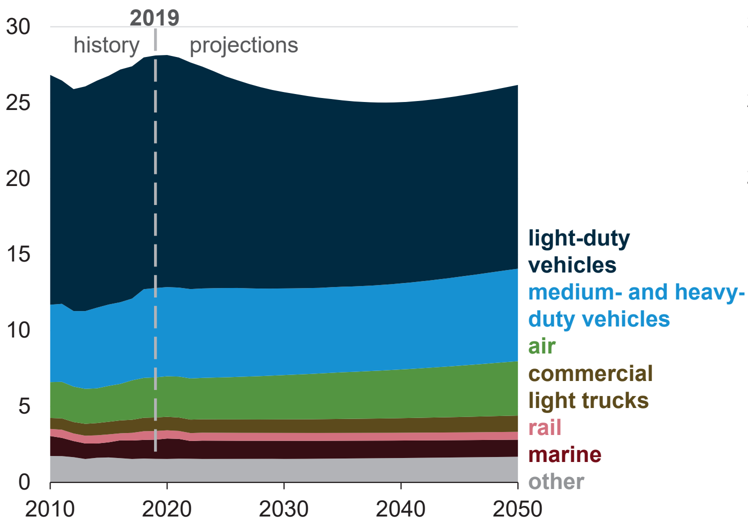
- The utilization rate of coal plants has fallen significantly in recent years as declining natural gas prices have led to a shift in economics between existing coal-fired and natural gas-fired combined-cycle generators. In 2019, the average capacity factor of the U.S. coal-fired fleet was 48% compared with an average natural gas-fired combined-cycle capacity factor of 58%. The low capacity factor for coal plants reflects a certain amount of idled inefficient capacity, which the Reference case projects will retire by 2025 as a result of the ACE rule. After 2025, the installed coal-fired capacity level is much lower because only the most efficient plants remain online. As a result, the average capacity factor for the fleet recovers quickly and stabilizes at about 65%.

Transportation

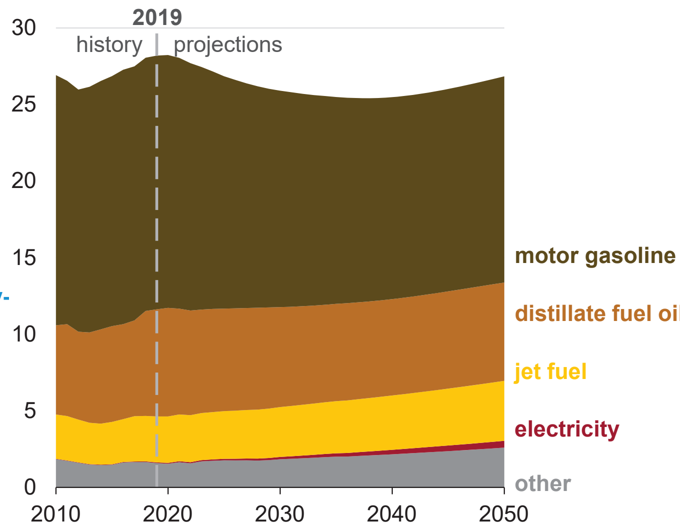
Transportation energy consumption peaks in 2020 in the AEO2020 Reference case because rising fuel efficiency more than offsets the effects of increases in total travel and freight movements, but this trend reverses toward the end of the projection period.

Transportation energy consumption declines through the 2030s in the AEO2020 Reference case—

Transportation sector consumption (by type)
(AEO2020 Reference case)
quadrillion British thermal units



Transportation sector consumption (by fuel)
(AEO2020 Reference case)
quadrillion British thermal units

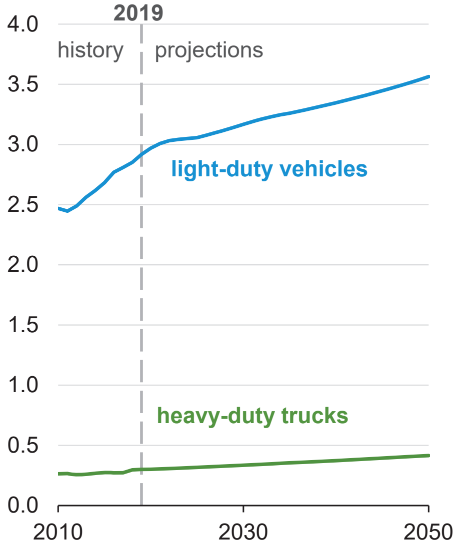


—because increases in fuel economy more than offset growth in vehicle miles traveled

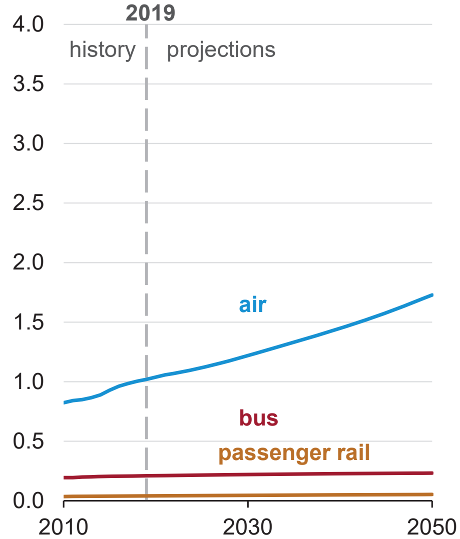
- Increases in fuel economy standards drive the decrease in U.S. motor gasoline consumption, which declines by 19% through 2050.
- Continued growth of on-road travel increases energy use later in the projection period because the travel demand for both light- and heavy-duty vehicles outpaces fuel economy improvements that result from regulatory requirements. Fuel efficiency regulations require no additional efficiency increases for new light-duty vehicles after 2025 and for new heavy-duty vehicles after 2027.
- Although increases in fuel efficiency standards slow growth in heavy-duty vehicle energy consumption and related diesel use, overall energy consumption for heavy-duty vehicles increases 4% through 2050 as a result of rising economic activity that increases demand for freight truck travel.
- Electricity is the fastest-growing energy source in the transportation sector, increasing on average 7.4% per year by 2050 as a result of increased demand for electric light-duty vehicles. Despite this growth, electricity accounts for less than 2% of transportation fuel consumption in 2050.
- Jet fuel consumption also increases through the projection period, rising 31% by 2050 because increases in air transportation outpace increases in aircraft fuel efficiency.
- Motor gasoline and distillate fuel oil's combined share of total transportation energy consumption decreases from 84% in 2019 to 74% in 2050.

Passenger travel increases across all transportation modes in the AEO2020 Reference case through 2050—

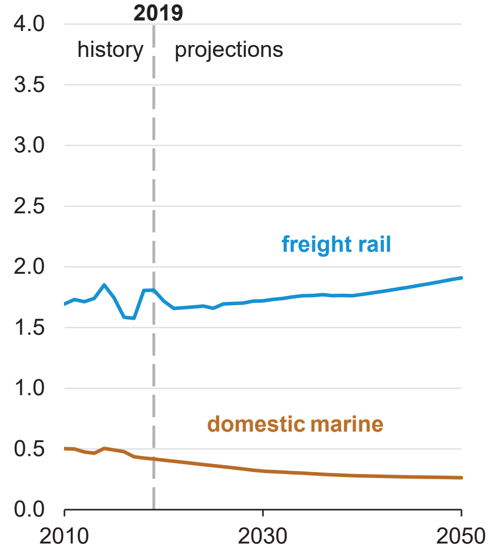
Vehicle travel
(AEO2020 Reference case)
trillion vehicle miles



Passenger travel
(AEO2020 Reference case)
trillion revenue passenger miles



Rail and domestic shipping
(AEO2020 Reference case)
trillion ton-miles traveled



—and freight movement increases across all modes except domestic marine

- Light-duty vehicle miles traveled increase by 22% in the AEO2020 Reference case, growing from 2.9 trillion miles in 2019 to 3.6 trillion miles in 2050 as a result of rising incomes and growing population.

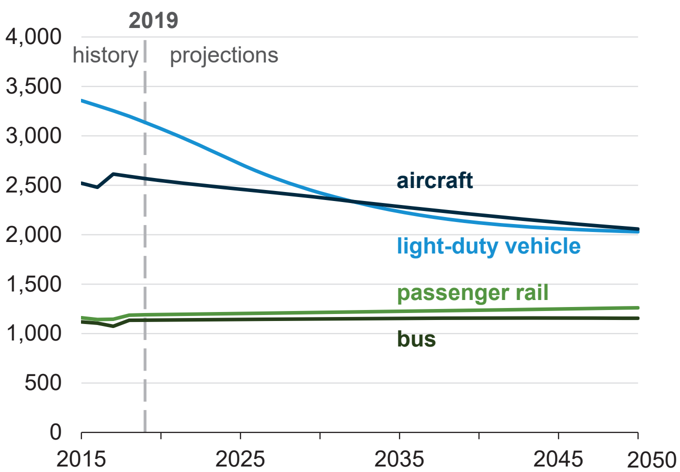
- Truck vehicle miles traveled, the dominant mode of freight movement in the United States, grow by 38%, from 300 billion miles in 2019 to 415 billion miles in 2050, as a result of increased economic activity. Freight rail ton-miles decline significantly in the early part of the projection period as a result of reduced U.S. coal shipments, but overall, freight rail ton-miles grow by 6% during the projection period, led primarily by rising industrial output.

- Air travel grows 70% from 1,020 billion revenue passenger miles to 1,729 billion revenue passenger miles through the projection period in the Reference case because of increased demand for global connectivity and rising personal incomes. Bus and passenger rail travel increase 11% and 30%, respectively.

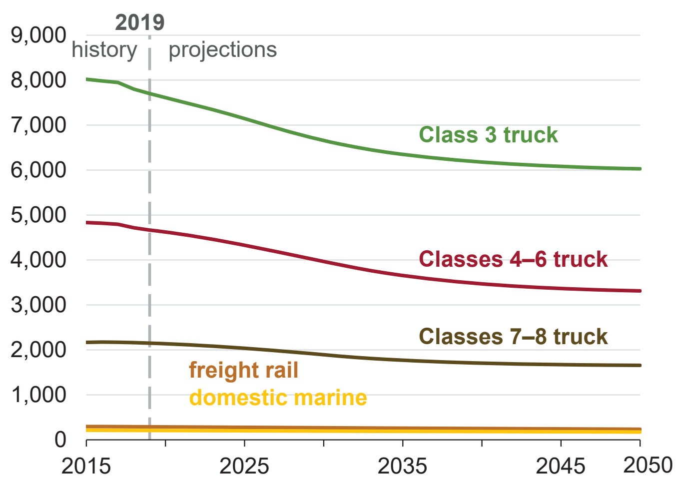
- Domestic marine shipments decline modestly during the projection period, continuing a historical trend related to logistical and economic competition with other freight modes.

Energy intensity decreases across most transportation modes in the AEO2020 Reference case—

Passenger mode energy intensity (AEO2020 Reference case)
British thermal units per passenger-mile



Freight mode energy intensity (AEO2020 Reference case)
British thermal units per ton-mile



—because of policy, economic, and technological factors

- Energy use per passenger-mile of travel in light-duty vehicles declines nearly 35% by 2050 in the AEO2020 Reference case as newer, more fuel-efficient vehicles enter the market, including both more efficient conventional gasoline vehicles and highly efficient alternatives such as battery electric vehicles. Energy efficiencies for light-duty vehicles are affected by current federal fuel economy and greenhouse gas emissions standards.

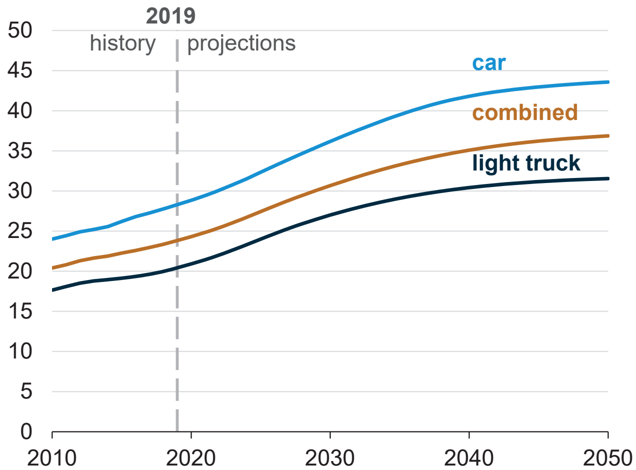
- Energy use per passenger-mile of travel in aircraft decreases because of the economically driven adoption of energy-efficient technology and practices. Energy use per passenger-mile of travel on passenger rail and buses, already relatively energy-efficient modes of travel per passenger-mile, remains relatively constant.

- Energy use per ton-mile of travel by freight modes decreases, led by increases in the fuel economy of heavy-duty trucks across all weight classes as the second phase of heavy-duty vehicle efficiency and greenhouse gas standards take full effect in 2027.

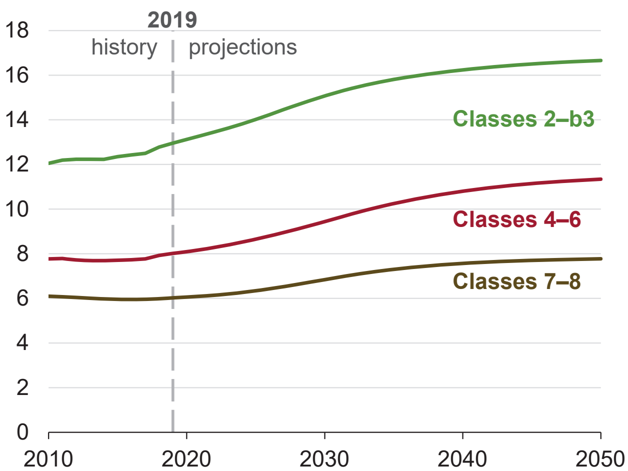
- Gains in energy efficiency offset increases in travel for passenger and freight modes. These efficiency gains decrease energy consumption by light-duty vehicles in the projection period and temper the rise in energy consumption by other transportation modes.

Fuel economy of all on-road vehicles increases in the AEO2020 Reference case—

Light–duty fuel economy (AEO2020 Reference case)
miles per gallon (all vehicles)



Heavy–duty fuel economy (AEO2020 Reference case)
miles per gallon (all vehicles)



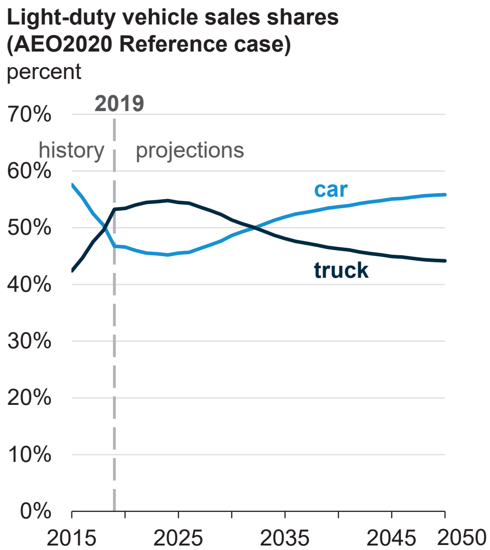
—across all vehicle types throughout the projection period

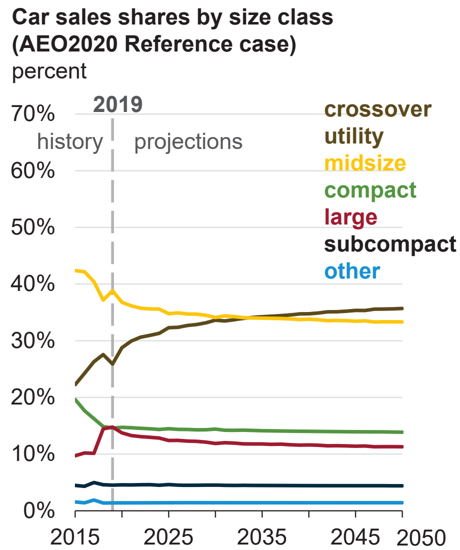
- Across all light-duty vehicles in use, fuel economy increases by 55% by 2050 in the AEO2020 Reference case as newer, more fuel-efficient vehicles enter the market and cars, which are more fuel efficient than light trucks, gain market share during the projection period. The fuel economy of cars increases from 28.3 miles per gallon (mpg) to 43.6 mpg, and the fuel economy for new light trucks increases from 20.4 mpg to 31.6 mpg.

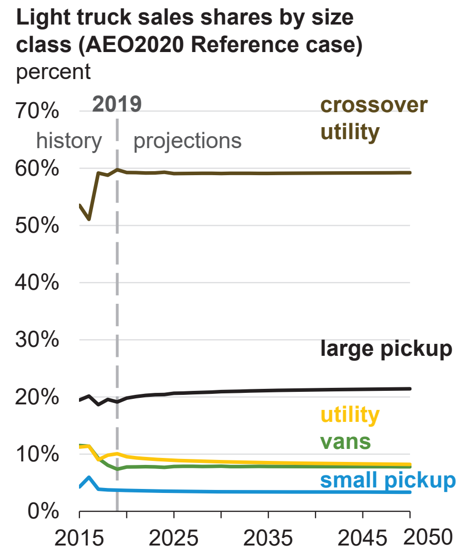
- Fuel economy of the heavy-duty vehicles in use improves across all weight classes as the efficiency improvements required under the second phase of heavy-duty vehicle efficiency and greenhouse gas standards take full effect. Phase II of the heavy-duty vehicle efficiency and greenhouse gas standards reaches the maximum requirements in 2027. Heavy-duty vehicle fuel economy continues to improve as older vehicles are replaced with newer, more efficient vehicles.

- Gains in fuel economy temper heavy-duty vehicle energy consumption growth and decrease light-duty vehicle energy consumption. For heavy-duty vehicles after 2040, increasing vehicle travel outweighs fuel economy improvements, leading to increases in fuel demand.

Sales of more fuel-efficient cars and light-truck crossover utility vehicles increase in the AEO2020 Reference case—







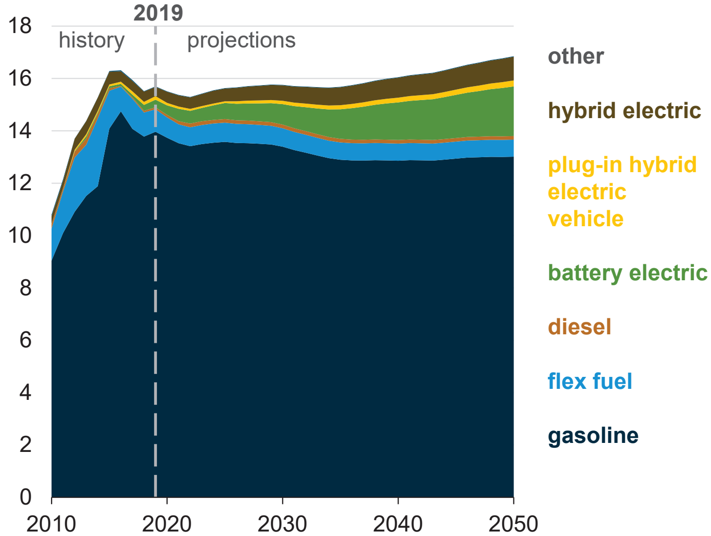
—but other vehicle types maintain significant market share through 2050

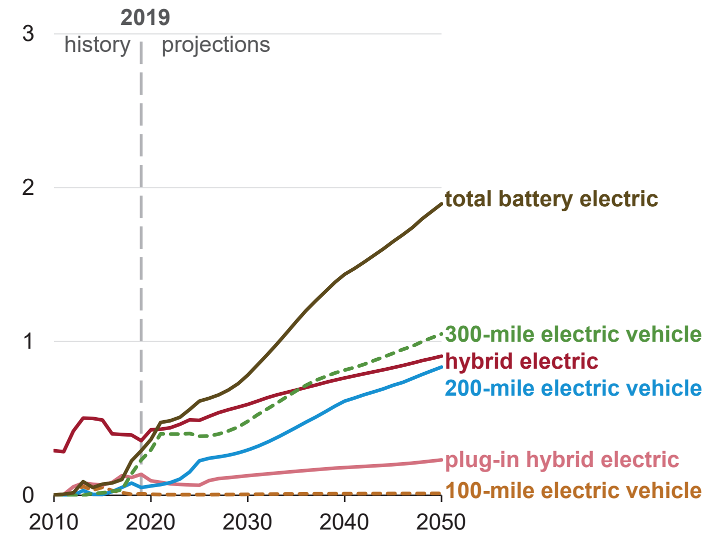
- In the AEO2020 Reference case, passenger cars gain market share in the light-duty vehicle market relative to light-duty trucks because they have higher fuel efficiency in periods when motor gasoline prices increase. They also gain market share because crossover utility vehicles, often classified as passenger cars, may replace lower fuel economy light-truck classified utility vehicles as a result of increasing availability and popularity.

- Light trucks lose some of their share in the light-duty vehicle market, and in terms of number of units sold, the classifications within light trucks shift from traditional vans and utility vehicles toward crossover utility vehicles that have higher fuel economy.

- Combined car and light-truck classified crossover utility vehicles reach 46% of new light-duty vehicle sales in 2050, largely taking away sales from traditional compact, midsize, and large cars and from truck-based sport utility vehicles.

Alternative and electric vehicles gain market share in the AEO2020 Reference case—





—but gasoline vehicles remain the dominant vehicle type through 2050

- The combined share of sales from gasoline and flex-fuel vehicles (which use gasoline blended with up to 85% ethanol) declines from 94% in 2019 to 81% in 2050 in the AEO2020 Reference case because of growth in sales of battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), and hybrid electric vehicles. BEV sales increase faster than any other type of vehicle sale, growing on average by 6% per year.

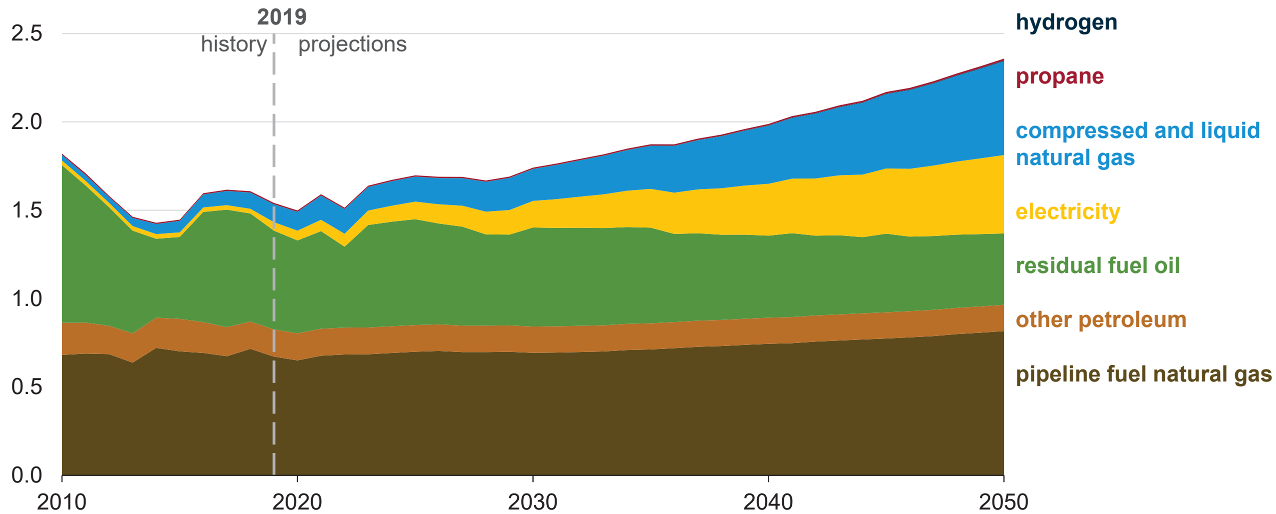
- Sales of the longer-ranged 200- and 300-mile BEVs grow during the entire projection period, tempering sales of the shorter-range 100-mile BEV and PHEV. Sales for the 200- and 300-mile BEVs increase from 280,000 in 2019 to 1.9 million in 2050, while sales of PHEVs increase from 137,000 in 2019 to 230,000 in 2050.

- Hybrid electric vehicle sales increase 3.1% per year, rising to more than 900,000 new vehicles sold by the end of the projection period.

- New light-duty vehicles of all fuel types show significant improvements in fuel economy because of compliance with increasing fuel economy standards. Light-duty vehicle fuel economy rises by 55% through the projection period.

Consumption of transportation fuels grows considerably in the AEO2020 Reference case through the projection period—

Transportation sector consumption of minor petroleum and alternative fuels (AEO2020 Reference case)
quadrillion British thermal units



—because of increased use of electricity and natural gas

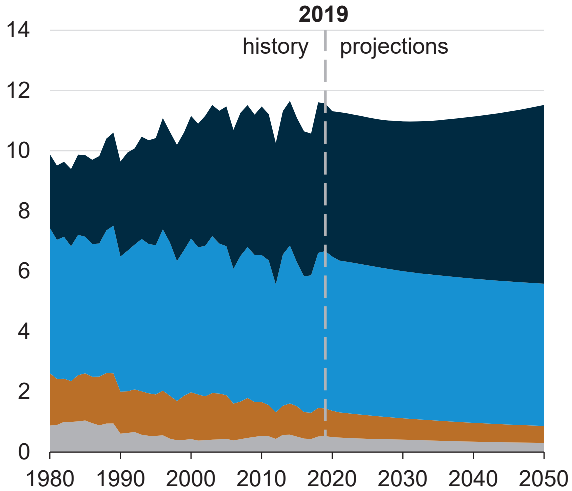
- Electricity use in the transportation sector increases sharply after 2020 in the AEO2020 Reference case because of a rise in the sale of new battery-electric and plug-in hybrid-electric light-duty vehicles.
- Natural gas consumption increases through 2050 because natural gas is increasingly used as a fuel for heavy-duty vehicles and freight rail.
- In the later years of the projection period, liquefied natural gas is used in the maritime industry as an alternative to burning high-sulfur residual fuel oil to meet the new standards set for marine fuels under the International Convention for the Prevention of Pollution from Ships (MARPOL convention).

Buildings

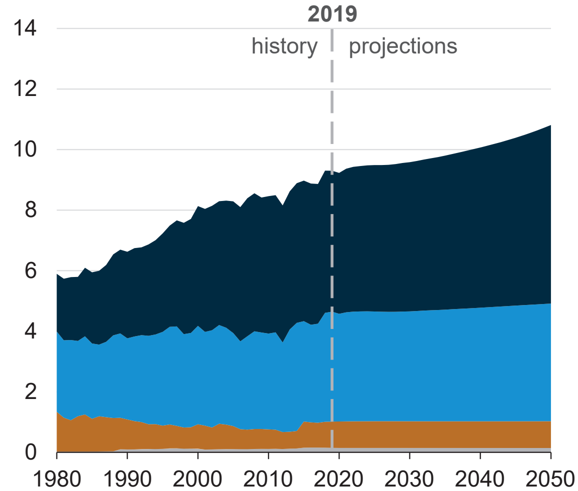
Delivered energy consumption in the U.S. buildings sector grows gradually from 2019 to 2050 in the Reference case, based, in part, on currently established efficiency standards and incentives. EIA anticipates distributed solar capacity to grow throughout the projection period based on near-term incentives, declining costs, and demographic factors.

Residential and commercial energy consumption grows slowly in the AEO2020 Reference case—

Residential sector delivered energy consumption (AEO2020 Reference case)
quadrillion British thermal units



Commercial sector delivered energy consumption (AEO2020 Reference case)
quadrillion British thermal units



electricity **natural gas** **petroleum and other liquids** **other**

—accounting for changes to energy efficiency standards and technological advances

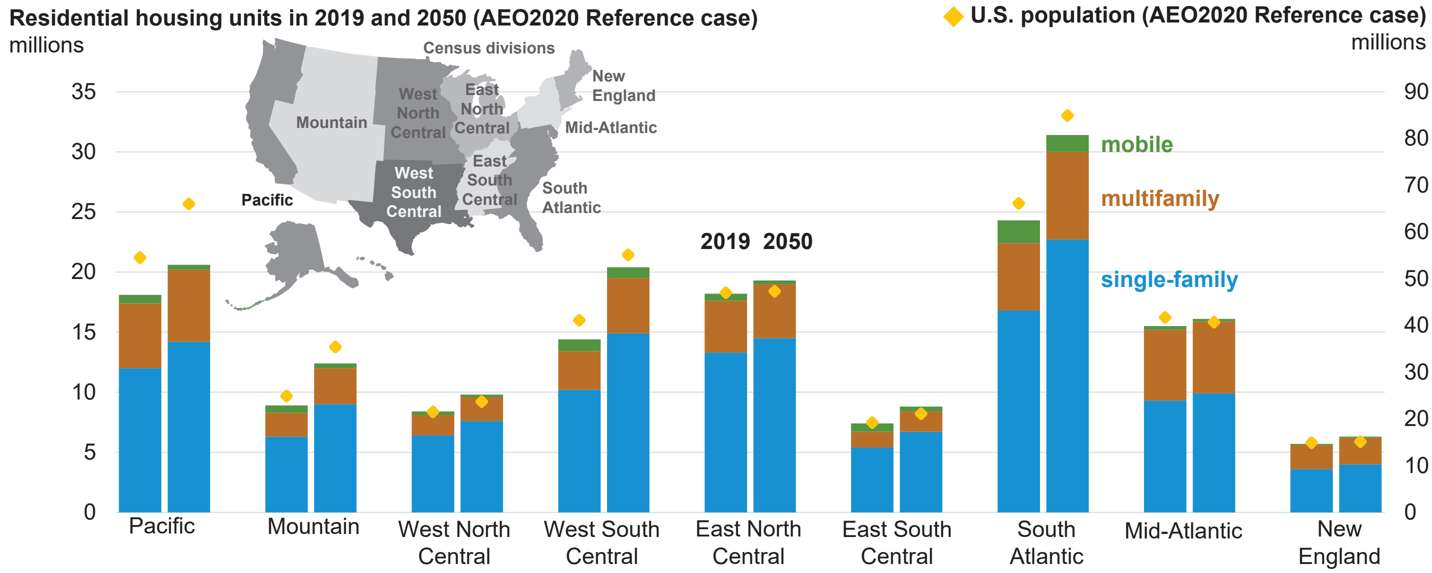
- Total delivered energy consumption in the U.S. buildings sector grows slowly through the AEO2020 Reference case projection period, 2019 to 2050, by 0.2% per year, as energy efficiency improvements, increases in distributed electricity generation, and regional shifts in the population partially offset the impacts of higher growth rates in population, number of households, and commercial floorspace.

- Purchased electricity consumption grows in both the residential and commercial sectors as a result of increased demand for appliances, devices, and equipment that use electricity. In the Reference case, purchased electricity increases by 0.6% and 0.8% per year in the residential and commercial sectors, respectively, through 2050.

- Natural gas consumption by commercial buildings grows by 0.2% per year through the projection period, led by increases in water heating and cooking. Consumption of natural gas in the residential sector falls by 0.3% per year as its use for space heating continues to decline.

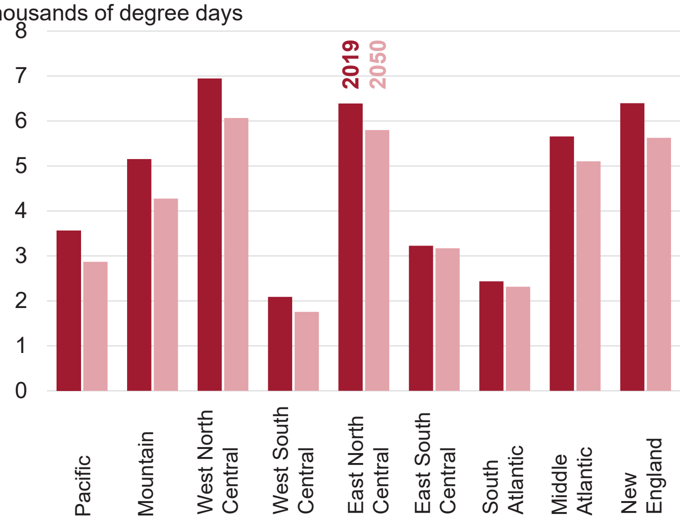
- If not for the contribution of distributed generation sources, particularly rooftop solar, purchased electricity consumption in residential and commercial buildings would be 5% and 3% higher, respectively, by the end of the projection period.

Population and residential housing stocks continue to grow mostly in the South and West between 2019 and 2050

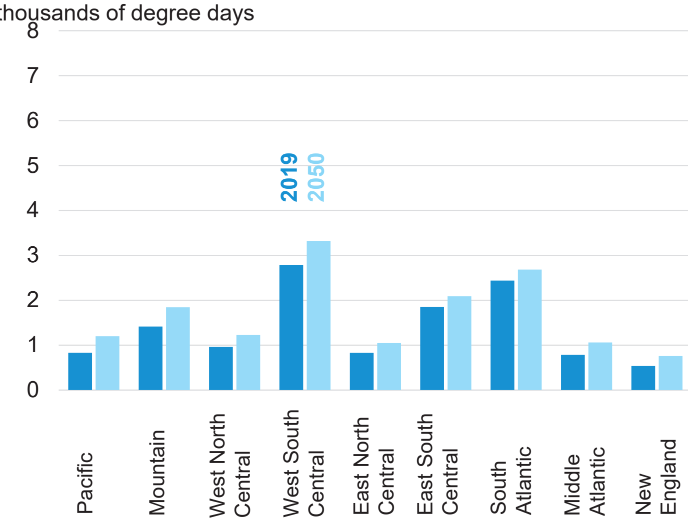


As a result of population shifts, overall U.S. heating needs decrease and cooling needs increase—

Population-weighted heating degree days by census division (AEO2020 Reference case)
thousands of degree days



Population-weighted cooling degree days by census division (AEO2020 Reference case)
thousands of degree days

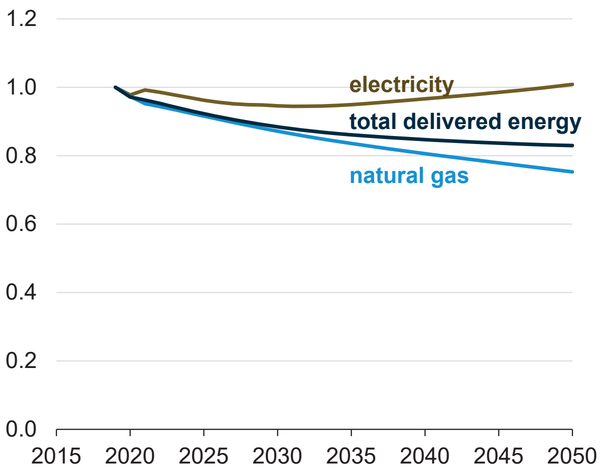


—especially in warmer regions with higher space cooling demand

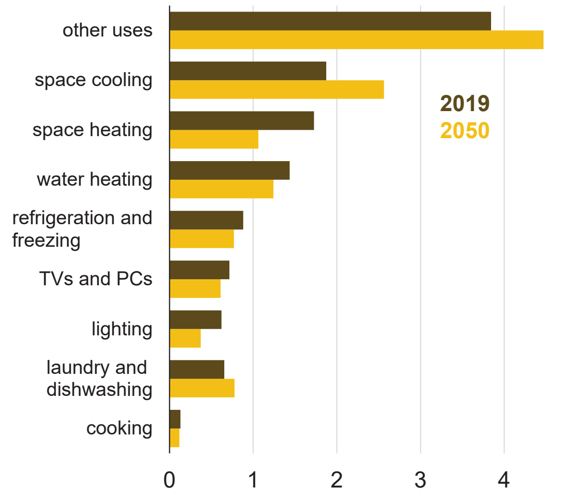
- The number of U.S. households increases by an average of 0.6% per year in the AEO2020 Reference case through 2050, and single-family homes grow the fastest, at 0.7% per year. The stock of multifamily homes grows at a rate of 0.6% per year, while mobile home stocks decrease by 1.2% per year and are the only category EIA does not expect to grow.
- Cooling-dominated West South Central and South Atlantic Census Divisions—as well as the Mountain Census Division—experience average annual housing stock growth that exceeds the national average. 12.2 million housing units are added across these areas by 2050.
- The size of housing units also continues to grow; the national average floorspace per home increases 0.3% per year from 1,786 square feet in 2019 to 1,987 square feet in 2050.
- Demand for space heating from fuels such as natural gas, distillate fuel oil, propane, and electricity decreases through 2050 as a result of fewer heating degree days (HDDs)—a measure of how cold a location is over a time period relative to a base temperature.
- Demand for space cooling from electricity increases through 2050 as a result of more cooling degree days (CDDs)—a measure of how warm a location is over a time period relative to a base temperature.
- EIA uses historical and near-term forecast HDDs and CDDs sourced from the National Oceanic and Atmospheric Administration. EIA uses this historical data and population projections to develop a 30-year linear trend for projecting population-weighted HDDs and CDDs.

U.S. residential energy intensity decreases in the AEO2020 Reference case—

Residential delivered energy intensity index (AEO2020 Reference case)
indexed annual energy use per household, 2019 = 1.0



Residential purchased electricity intensity (AEO2020 Reference case)
thousand kilowatthours per household



—although changes in electricity consumption vary by end use

- In the AEO2020 Reference case, U.S. total delivered residential energy intensity, defined as annual delivered energy use per household, decreases by 17% between 2019 and 2050 as the number of households grows faster than energy use. The main factors contributing to this decline include gains in appliance efficiency, onsite electricity generation (e.g., solar photovoltaic), utility energy efficiency rebates, rising residential natural gas prices, lower space heating demand, and a continued population shift to warmer regions.

- Lighting electricity consumption per U.S. household declines faster than other electric end uses as a result of compliance with the minimum performance requirements of the Energy Independence and Security Act of 2007. The federal standards effectively eliminate low-efficacy incandescent lamps, replacing them with more energy-efficient light-emitting diodes (LEDs) and compact fluorescent lamps (CFLs) by 2020. Energy efficiency incentives also accelerate LED and CFL penetration before 2020. In 2050, purchased electricity intensity for lighting is 40% lower than in 2019.

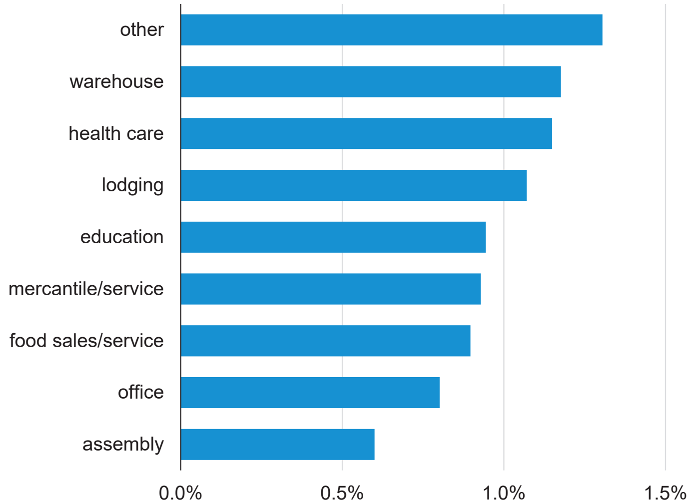
- As near-term appliance standards result in efficiency gains beyond those gains caused by market forces and technological change, electricity intensity declines before 2030 and then increases slightly as sector growth overtakes additional efficiency gains.

- Natural gas and electric equipment increasingly replace distillate fuel oil- and propane-fired equipment.

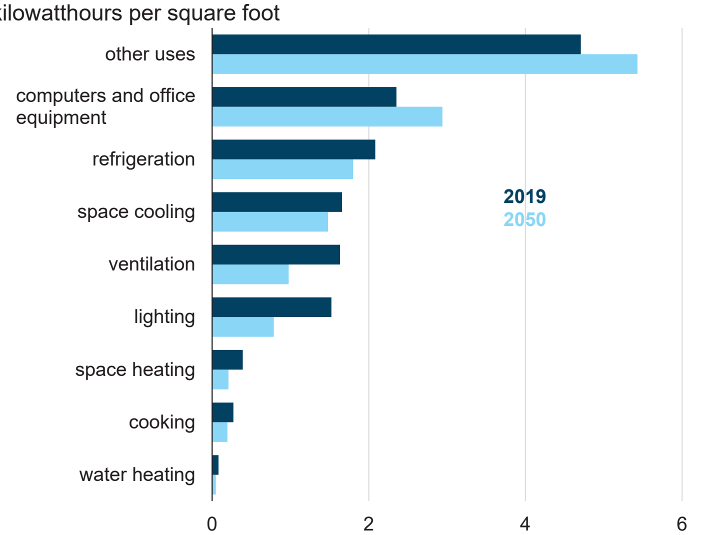
- Electricity intensity of other uses increases throughout the projection period with expected growth in the use of electronic equipment, such as security systems and rechargeable devices.

AEO2020 Reference case U.S. commercial energy consumption growth is tempered by increased equipment and lighting efficiencies—

Commercial floorspace growth
(AEO2020 Reference case)
percent compound annual growth rate



Commercial purchased electricity intensity
(AEO2020 Reference case)
kilowatthours per square foot



—but growing floorspace, declining electricity prices, and expanding information technology needs drive an overall increase in electricity consumption

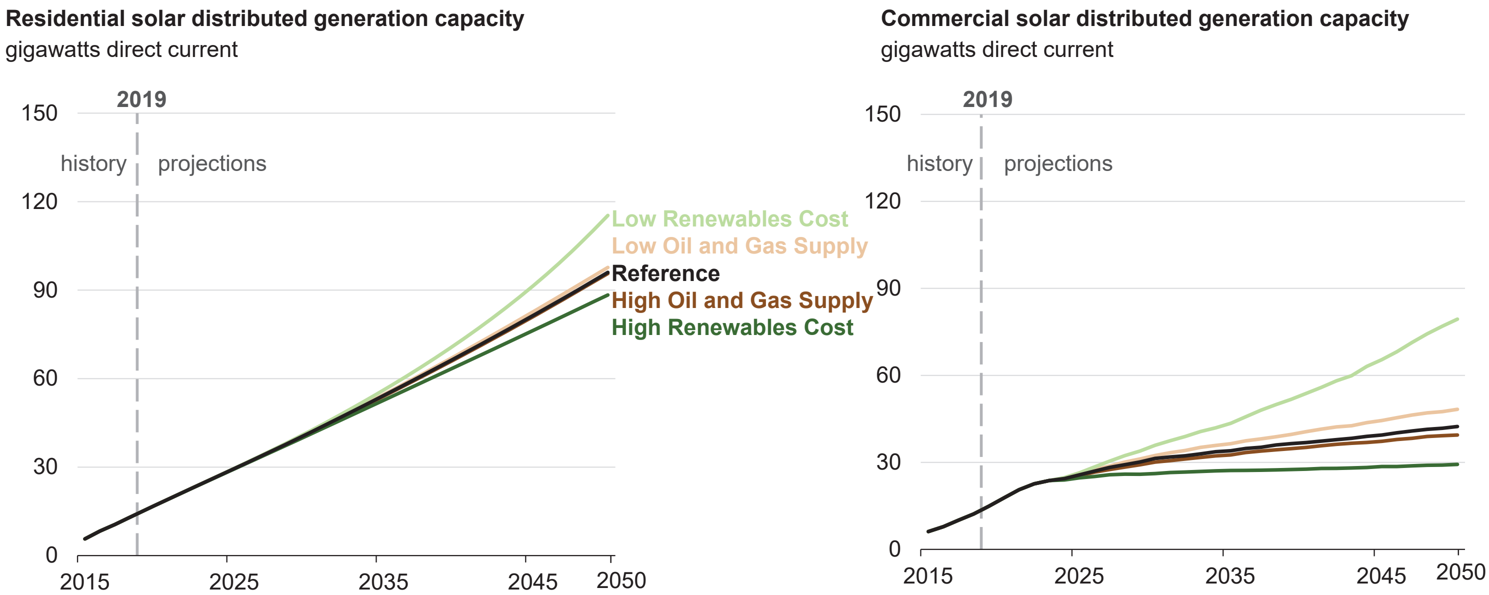
- Commercial floorspace grows by an average 1% per year in the AEO2020 Reference case through the projection period, reflecting rising economic activity. Some of the fastest-growing building types, including health care and lodging, are also among the most energy intensive.

- Commercial electricity intensity, defined as electricity consumption per square foot of commercial floorspace, declines at an average of 0.2% per year through the projection period. Combined with floorspace growth, the decline in intensity results in an overall increase in electricity consumption of 0.8% per year.

- Lighting accounts for the steepest intensity decline among the major end uses, falling by more than 2% per year throughout the projection period. Lower costs and energy efficiency incentives lead efficient LEDs to displace linear fluorescent lighting as the dominant commercial lighting technology by 2030. Similarly, intensities for major end uses such as ventilation, space heating and cooling, and refrigeration decline over time. However, other uses such as office equipment (not including computers), whose electricity intensity increases by 1.6% per year, counterbalance these declines.

- Despite increasing equipment efficiencies, declining electricity prices encourage greater use of energy-consuming appliances and devices.

Rooftop solar PV adoption grows between 2019 and 2050—

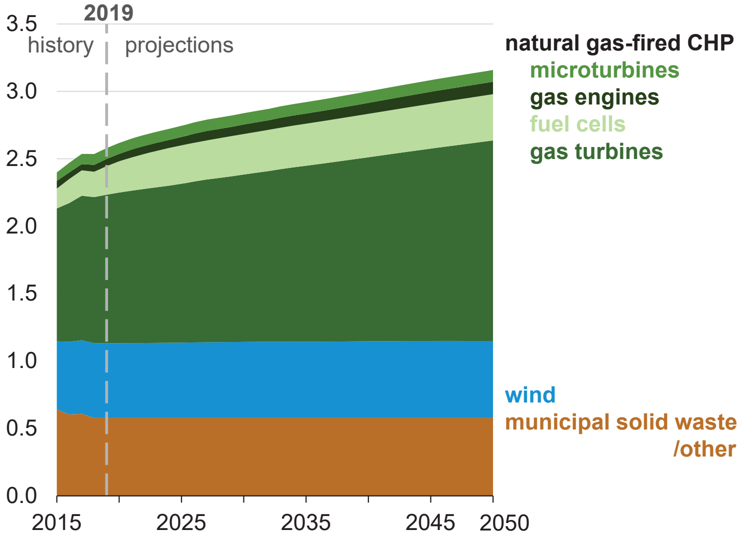


—with residential growth outpacing commercial growth in later years

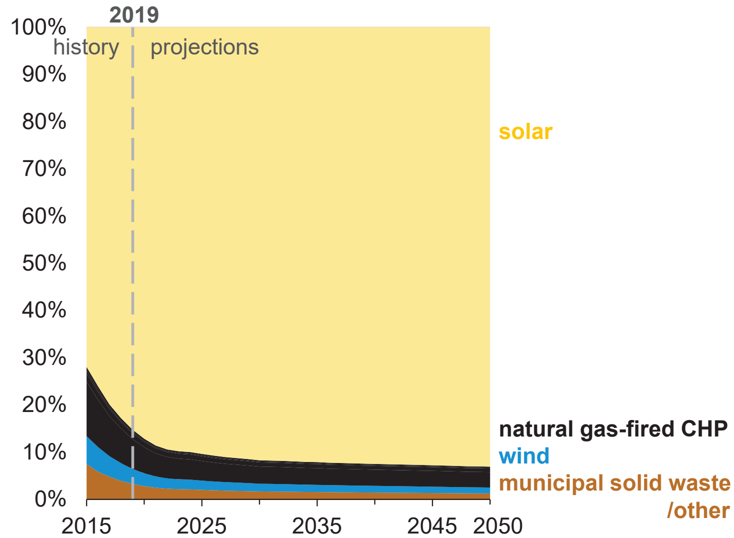
- Residential solar photovoltaic (PV) capacity increases by an average of 6.1% per year through 2050 in the AEO2020 Reference case, and commercial PV capacity increases by an average of 3.4% per year.
- PV costs decline most rapidly before 2030, despite the phasedown in the federal Energy Investment Tax Credit (ITC) from 30% in 2019 to 10% in 2022 and the four-year Section 201 tariff levied on PV cells and modules in 2018.
- Declining installation costs drive steady commercial PV adoption, although capacity growth slows after 2030. Rising incomes, declining system costs, and social influences accelerate residential PV adoption.
- For both residential and commercial sectors, the High Renewables Cost case and Low Renewables Cost case vary the most from the Reference case. Commercial PV projections are particularly responsive to variations in installed cost; a spread of 50 GW between the Low Renewables Cost case and High Renewables Cost case is projected in 2050.
- PV growth is also sensitive to electricity prices. In 2050, electricity prices vary the most from the AEO2020 Reference case in the Low Oil and Gas Supply case, by 9.7% and 9.2% for the residential and commercial sectors, respectively. In response, residential PV capacity increases by 1.7% and commercial PV capacity increase by 14% relative to the AEO2020 Reference case.

Combined heat and power (CHP) and other non-solar sources of electric generation account for 15% of commercial onsite capacity in 2019 in the AEO2020 Reference case—

Commercial non-solar distributed generation capacity (AEO2020 Reference case)
gigawatts direct current



Commercial distributed generation capacity (AEO2020 Reference case)
percent

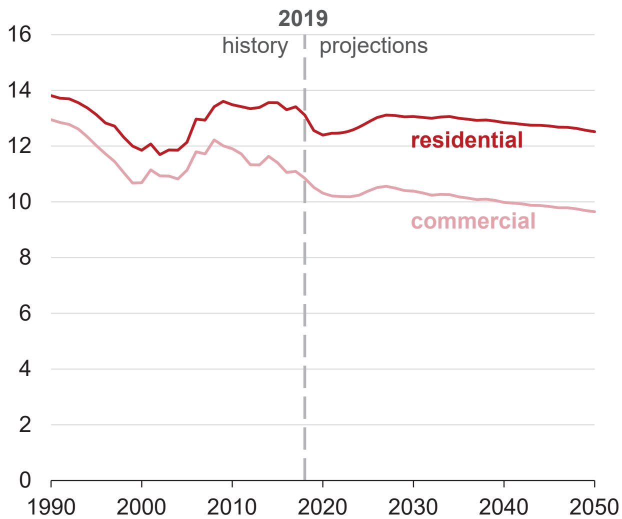


—but this share declines during the projection period as growth lags behind solar photovoltaic generation

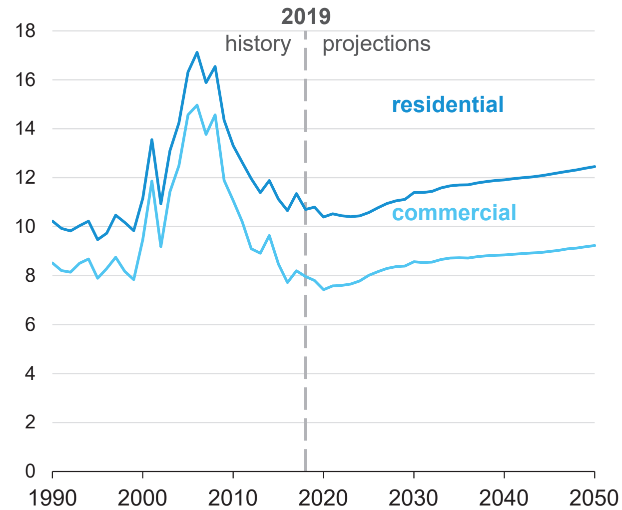
- Non-photovoltaic technologies, such as combined heat and power (CHP) and distributed wind, account for 15% of commercial distributed generation capacity in 2019 but only 7% by 2050 in the AEO2020 Reference case.
- Of the non-solar technologies, natural gas-fired CHP (namely, microturbine, reciprocating engine, fuel cell, and conventional turbine) capacity expands the fastest at an average of 1.1% per year. Incremental installed cost declines and performance improvements drive this growth, despite rising commercial natural gas prices, which increase by 0.5% per year through the projection period.
- The 2018 Bipartisan Budget Act extends the ITC provisions for qualifying CHP beginning construction before January 1, 2022. These tax credits contribute to growth in CHP in the short term.
- Wind generation capacity projections remain flat in AEO2020, in part, because of a lack of commercial mid-scale turbines (101 kilowatts to 1 megawatt) available in the U.S. market. The majority of recent commercial wind installations use large-scale turbines—the average in 2018 was 2.1 megawatts—but the commercial sector market potential for these larger turbines is limited.

Residential and commercial electricity prices decline slightly in the AEO2020 Reference case through 2050

Electricity prices (AEO2020 Reference case)
2019 cents per kilowatthour



Natural gas prices (AEO2020 Reference case)
2019 dollars per thousand cubic feet



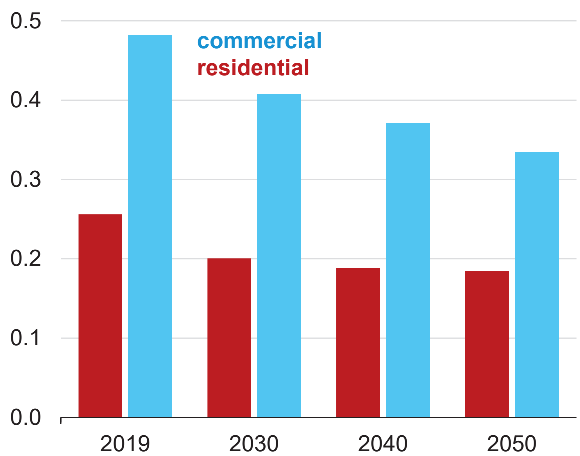
—while natural gas prices rise, moderating natural gas consumption

- AEO2020 Reference case electricity prices fall in the near term, primarily because utilities pass along savings from lower taxes under the Tax Cuts and Jobs Act of 2017. In addition, utilities are replacing more costly power plants with new plants that are less expensive to construct and operate, which also contributes to lower prices. Lower prices encourage more consumption in the near term in both sectors, although near-term efficiency standards and population shifts to warmer areas of the country moderate this trend.

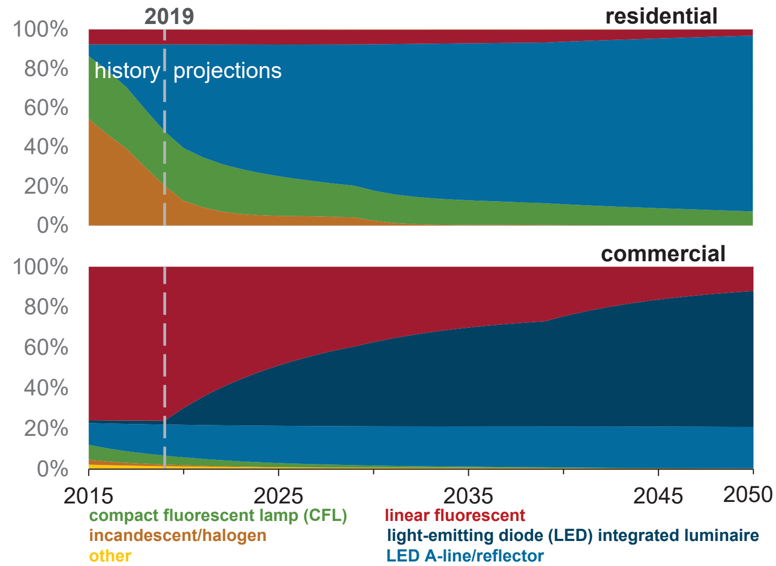
- Natural gas prices in both the residential and commercial sectors increase steadily, by an average of 0.5% per year, in the Reference case through 2050. Increasing natural gas prices decrease consumption in the residential sector and moderate consumption growth in the commercial sector.

Energy consumed to meet lighting needs decreases in the AEO2020 Reference case –

Delivered electricity consumed to meet lighting demand (AEO2020 Reference case)
quadrillion British thermal units



Lighting shares (AEO2020 Reference case)
percent



—driven by federal efficiency standards, declining upfront costs, and utility and state energy efficiency program incentives

- In 2019, 44% of residential light bulbs were LEDs, currently the most efficient light bulb technology available, and 17% of commercial lighting service demand was met by LED bulbs and fixtures. By 2050, these shares increase to 90% and 88%, respectively.

- Utility energy efficiency program incentives drive LED adoption in the AEO2020 Reference case during the short to medium term, reducing the upfront cost of purchasing LEDs by up to 40% until 2019. EIA assumes residential lighting subsidies will fall to 0% in 2020, but efficiency incentives continue to drive commercial adoption of LED lighting through 2029.

- Efficiency requirements under the Energy Independence and Security Act of 2007 eliminate inefficient incandescent bulbs from general service lighting (GSL) use after 2020, causing homes and businesses to switch to more efficient LED and CFL bulbs. Although we incorporate a U.S. Department of Energy final rule that narrows the definition of GSLs, about two-thirds of residential lighting falls under the revised definition.

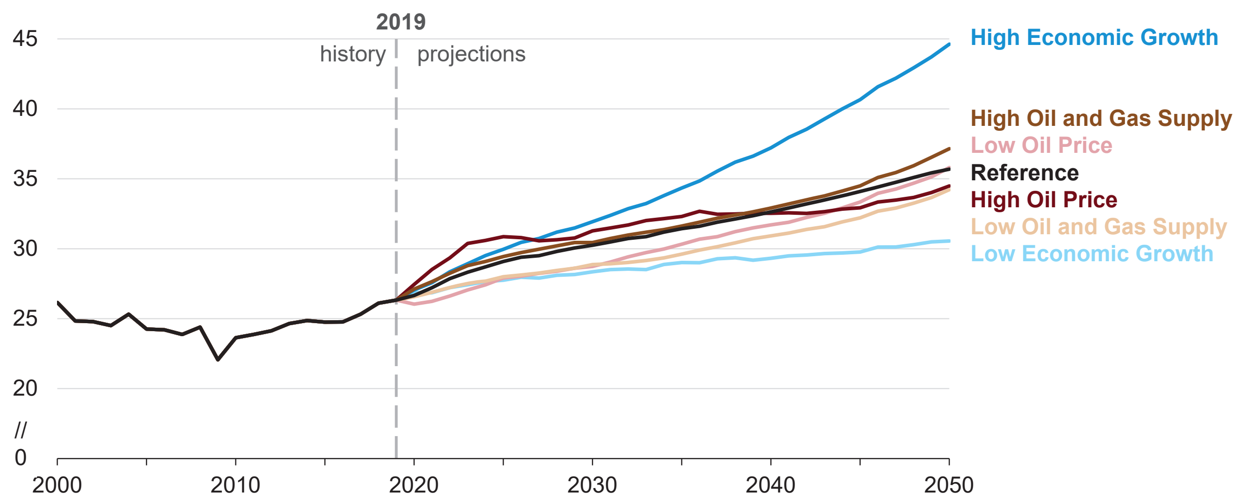
- Cost declines in LEDs drive expanded market share throughout the projection period. During the projection period, the AEO2020 shows the installed cost of residential GSL LEDs declines by 33% and the cost of commercial LED luminaires declines by up to 74%.

Industrial

As a result of projected economic growth and lower domestic energy prices relative to the world market, AEO2020 projects that energy consumption in the U.S. industrial sector will increase during the projection period across all cases. U.S. consumption of most energy sources, particularly natural gas, will increase significantly. Coal consumption, which flattens after 2020, is the only exception. Energy intensity declines across all cases as a result of technological improvements.

Consumption of delivered industrial energy grows in all AEO2020 cases—

AEO2020 industrial delivered energy consumption
quadrillion British thermal units



—driven by economic growth, but it is also affected by low prices and resource availability

- In the AEO2020 Reference case, U.S. delivered energy consumption in the industrial sector grows 36% from 26 quadrillion British thermal units (Btu) to 36 quadrillion Btu during the projection period.

- Industrial activity is closely correlated with economic activity. Therefore, changes in assumptions related to economic growth affect industrial sector energy consumption the most. The High Economic Growth case and the Low Economic Growth case vary the most from AEO2020 reference case projections of U.S. industrial sector energy consumption.

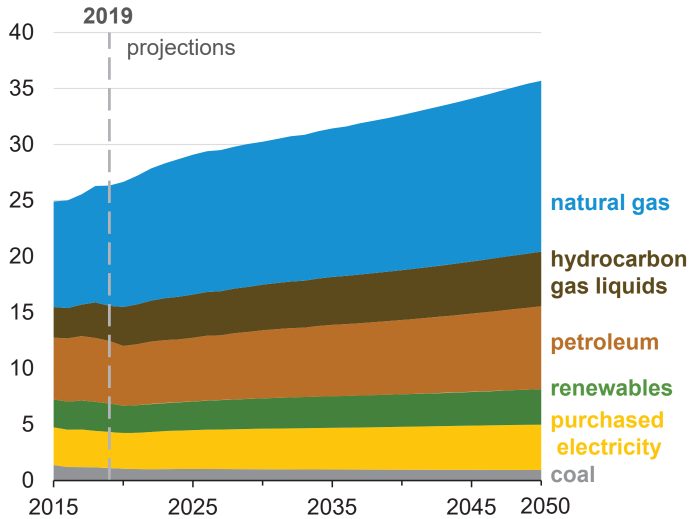
- Through the late 2020s, the High Oil Price case projects the fastest growth in industrial sector energy demand as a result of increased investment in the short term for more mining/oil extraction equipment and related activities (construction, cement, steel for drilling equipment, etc.). Eventually, higher oil prices dampen consumer spending in the long run, thereby lowering growth.

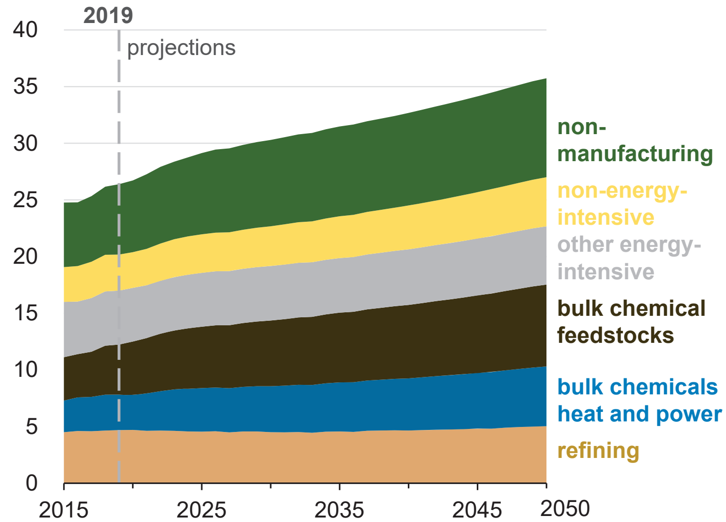
- Over the long term, industrial energy consumption is highest in the High Economic Growth case, reaching 45 quadrillion Btu in 2050, a 69% increase from 2019. With a faster growing economy, greater industrial activity in sectors such as food and fabricated metal products increases industrial energy use.

- Energy consumption in the High Oil and Gas Supply case is greater than in the Reference case as a result of increased crude oil and natural gas resources and improved extraction technologies that increase energy demand in the mining industry.

Industrial sector energy consumption increases fastest for natural gas and hydrocarbon gas liquids in the AEO2020 Reference case—

Industrial energy consumption by energy source and subsector (AEO2020 Reference case)
quadrillion British thermal units





—and bulk chemicals and nonmanufacturing are the fastest-growing industries in the sector

- Total U.S. industrial delivered energy consumption grows 1.0% per year on average during the projection period in the AEO2020 Reference case. Growth varies by fuel. EIA projects coal consumption to decline through the projection period, while natural gas and hydrocarbon gas liquids (HGL) consumption will grow fastest, reflecting strong supply growth and relatively low prices.

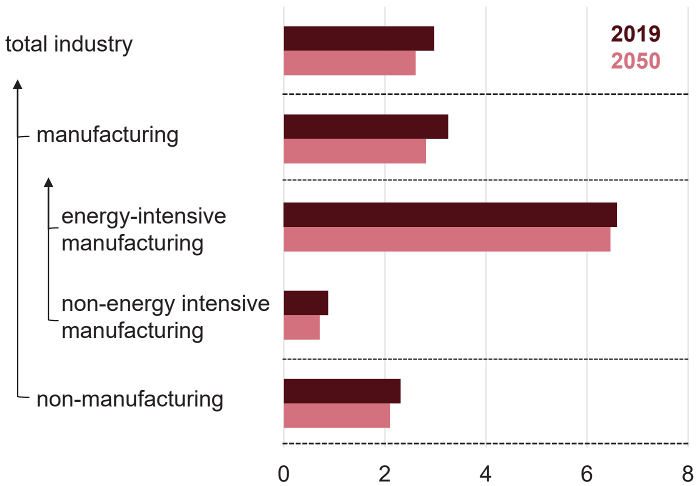
- During the projection period, industrial sector HGL consumption grows by 1.4% per year and natural gas consumption grows by 1.1% per year, as these fuels become more heavily used for heat and power and as feedstocks.

- Energy consumption in the bulk chemicals industry, including both heat and power and feedstocks, accounts for about 35% of total U.S. industrial energy consumption by the end of the projection period and grows at 1.6% per year.

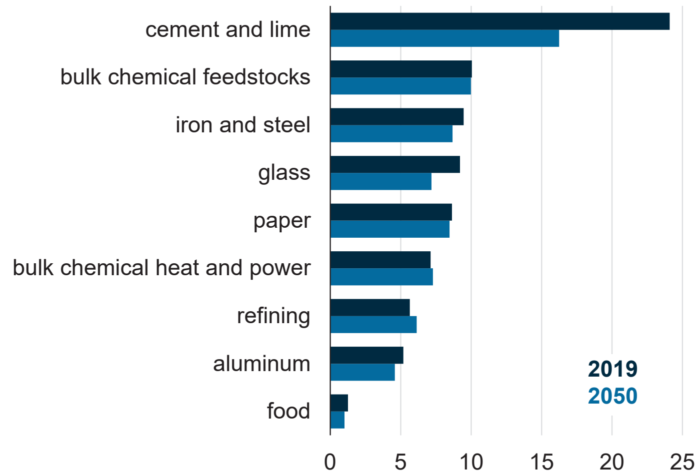
- Energy consumption in the other energy-intensive industries in the United States remains relatively flat during the projection period, growing on average 0.3% per year. Energy consumption in the iron and steel industry declines by 19% during the projection period, energy consumption in the paper industry increases by 11%, and energy consumption in the cement and lime industry consumption stays relatively flat.

In the AEO2020 Reference case, energy intensities decline in most heavy industries—

Energy intensity by subsector (AEO2020 Reference case)
trillion British thermal units per billion 2012 dollar shipments



Energy-intensive manufacturing (AEO2020 Reference case)
trillion British thermal units per billion 2012 dollar shipments



—reflecting industrial capital stock turnover and adoption of new, more energy-efficient technologies

- Energy intensity in the U.S. industrial sector (energy consumption per dollar of output) declines by 0.4% per year on average through 2050 in the AEO2020 Reference case. In manufacturing, energy intensity declines 0.5% per year through the projection period as a result of the increased energy efficiency of new capital equipment and the faster growth rate in non-energy-intensive manufacturing industries relative to energy-intensive manufacturing industries.

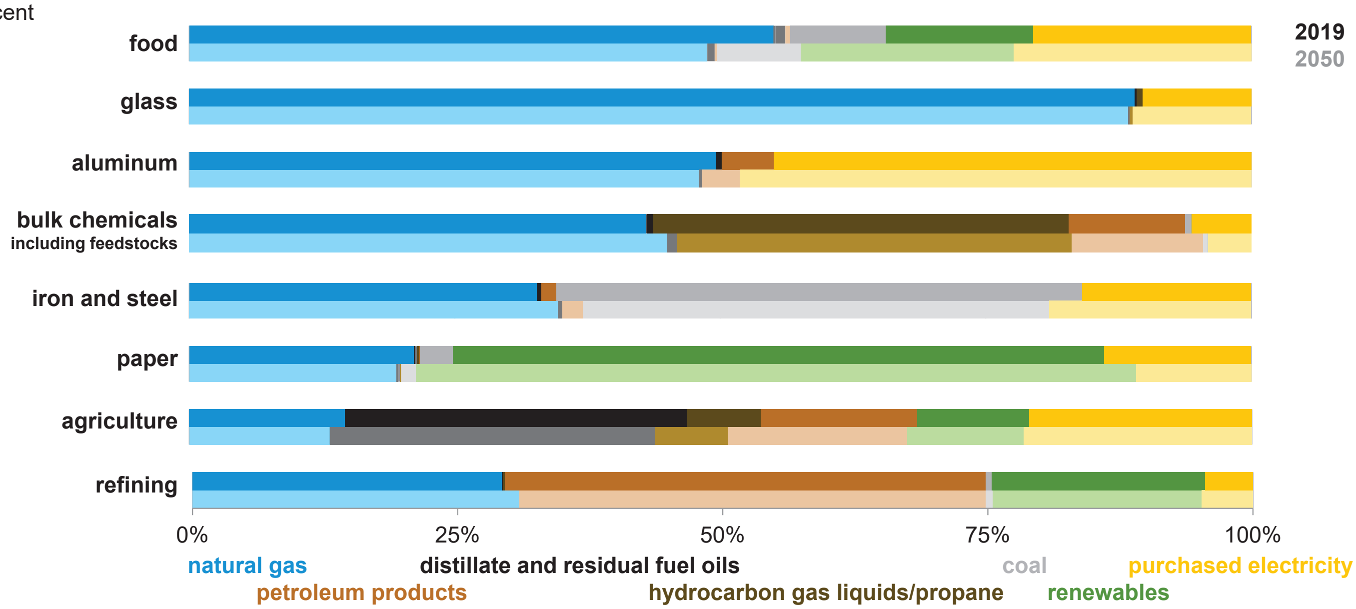
- Energy intensities in the refining sector and in the bulk chemical heat and power sector both increase as relatively low-cost natural gas increases production of lower-value commodities.

- Higher energy intensities in the refining sector and bulk chemical sector are offset by efficiency improvements in other energy-intensive industries, such as food (0.7% per year decline in energy intensity), glass (0.8% decline per year), and cement and lime (1.3% decline per year). The net result is an overall 2% decline in energy intensity for the energy-intensive manufacturing industries sector during the projection period.

- For some industries, large amounts of combined heat and power generation (CHP) may mask some efficiency gains. EIA includes CHP generation losses in industry energy consumption. Purchased electricity generation losses are accounted for in the electricity sector.

AEO2020 Reference case energy consumption by fuel varies across energy-intensive industries—

Energy consumption by energy source shares and industry (AEO2020 Reference case)
percent



—because some industries have greater capacity for fuel switching than others

- Natural gas (used primarily for process heat) remains the primary fuel in the U.S. food and glass industries in the AEO2020 Reference case, although its share declines through 2050. In the food industry, the share of renewables grows from 14% in 2019 to 20% in 2050. In the glass industry, natural gas continues to have the largest share, retaining more than an 88% share through the projection period.

- In the U.S. iron and steel industry, coal remains the primary fuel, although its share in the total energy mix for the sector declines from 50% in 2019 to 44% in 2050 as natural gas and electricity-fueled technologies become more widely used.

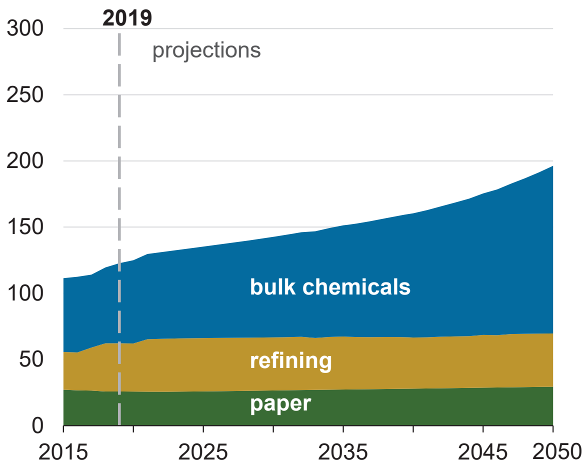
- The bulk chemicals industry consumes natural gas and HGLs for both heat and power and feedstock. The relatively low projected prices for both fuels result in continued high shares of total energy consumption and reduced shares of purchased electricity as CHP adoption grows.

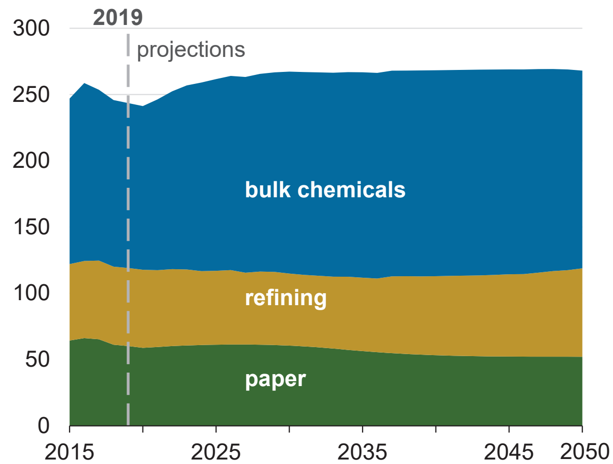
- In the United States, in addition to the food industry and, to some extent, refining (where bio-based feedstocks are used to produce blend-stocks for the transportation fuels sector), one of the highest shares of renewables consumption is in the paper industry, where black liquor (a byproduct of the pulping process) serves as a major fuel for boilers and on-site CHP. The renewables share of total energy consumed in the paper industry increases from 61% in 2019 to 68% in 2050.

- Petroleum remains the primary fuel for refining and for agriculture, where distillate fuels most of the on-field equipment.

Self-generation from combined heat and power (CHP), especially for bulk chemicals, accounts for most AEO2020 Reference case growth in industrial sector electricity consumption—

CHP generation and purchased electricity consumption for U.S. industries with the most installed CHP (AEO2020 Reference case)





—as quantities of purchased electricity remain fairly flat

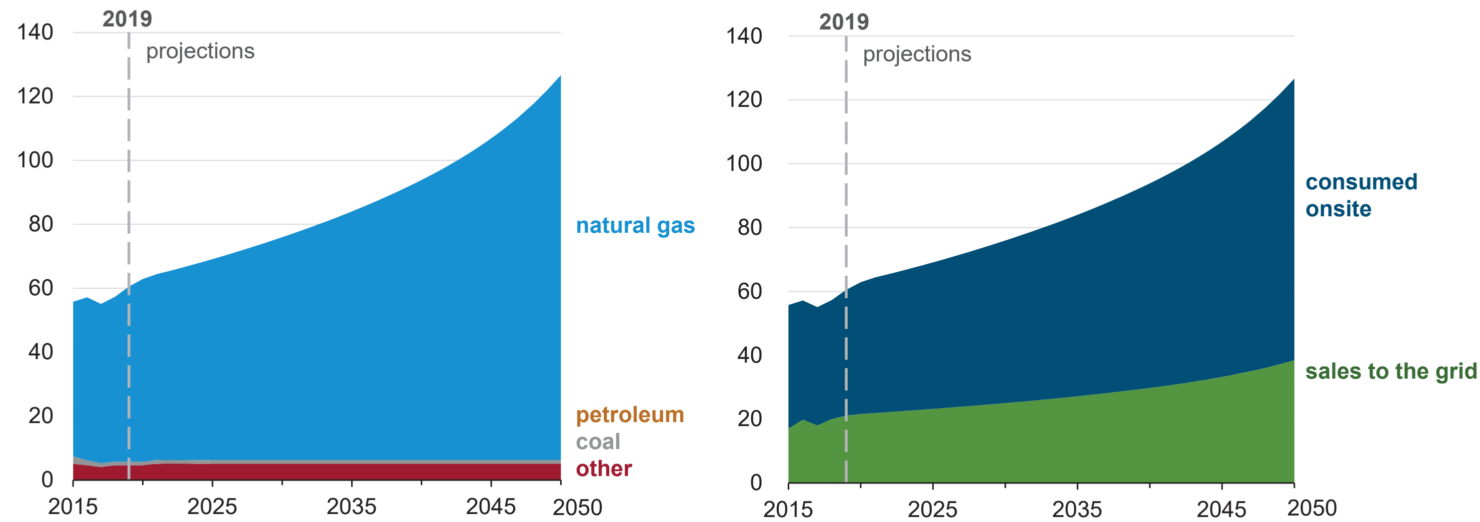
- AEO2020 Reference case electricity generation from CHP units in the U.S. bulk chemicals, refining, and paper industries (industries with the most CHP) grows 1.5% per year, from 125 billion kilowatthours (kWh) in 2019 to 196 billion kWh in 2050.

- The bulk chemical, refining, and paper industries use the most CHP in the United States because these large industries have high heating needs, and steam is readily available onsite to use for generation. The share of self-generated electricity to total electricity consumption in the sector rises from 34% in 2019 to 42% in 2050 because rapidly growing demand for industrial heat allows complementary power generation growth.

- Although natural gas accounts for more than 90% of the fuel used for CHP in the bulk chemicals industry in 2019 and 95% in 2050, petroleum products—in the form of residual oil, petroleum coke, and still gas and others—fuel some of the CHP capacity in the refining sector. In the paper industry, renewables such as black liquor fire CHP generation.

In the bulk chemicals industry, combined-heat-and-power (CHP) adoption grows in the AEO2020 Reference case; sales to the grid remain relatively flat as most generation fuels onsite consumption

Net CHP generation and disposition in the bulk chemicals sector, by fuel (AEO2020 Reference case)
billion kilowatthours

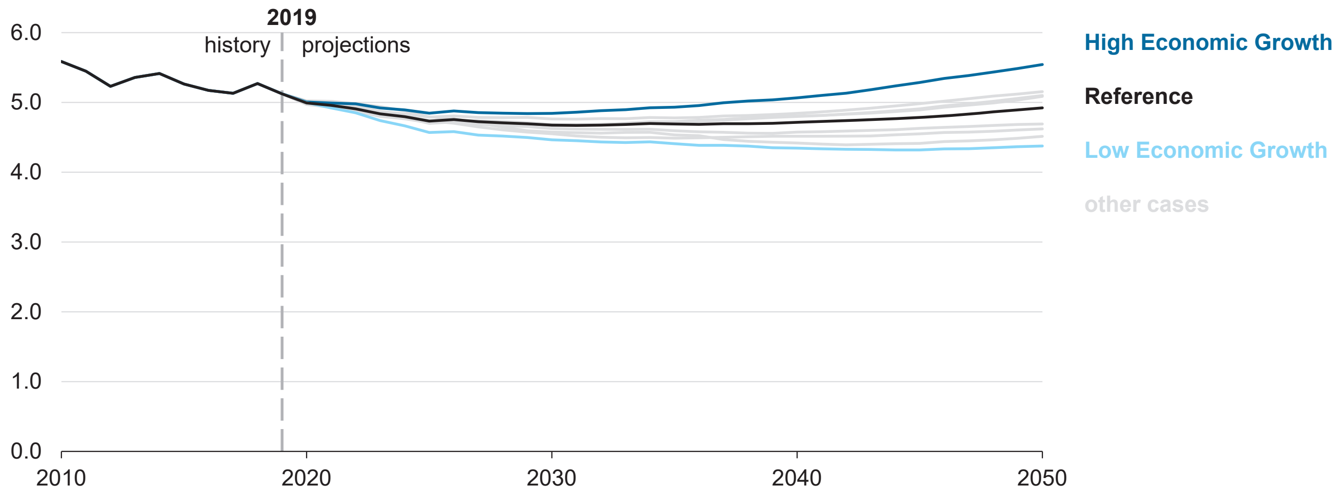


Emissions

Energy-related carbon dioxide emissions decrease until the mid-2020s in the AEO2020 Reference case as a result of changes in the fuel mix consumed by the electric power sector. After 2030, increases in energy demand in the other sectors—predominantly transportation and industrial—cause emissions to increase.

Economic growth is the biggest factor in carbon dioxide (CO_2) emissions —

AEO2020 U.S. energy-related CO2 emissions cases
billion metric tons

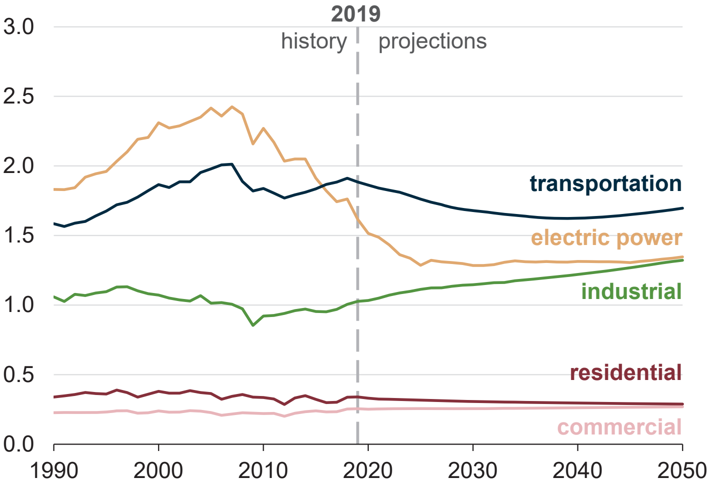


— and emissions in the High Economic Growth case rise faster than the Low Economic Growth case, as rapidly increasing energy demand outweighs improvements in efficiency

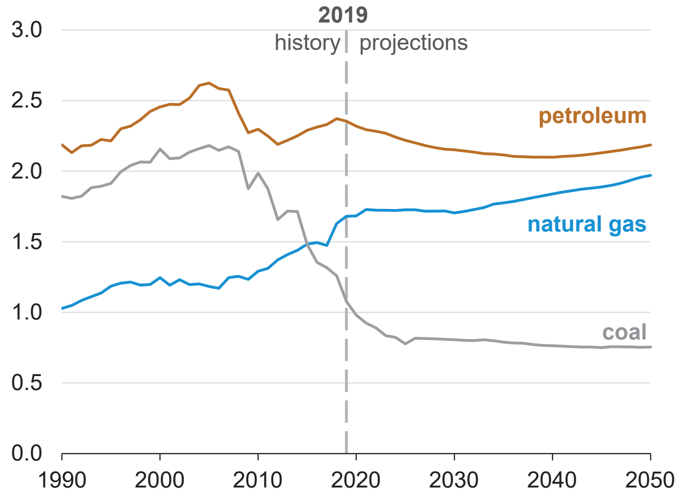
- Economic growth is the primary driver of energy demand and related CO_2 emissions.
- Energy-related CO_2 emissions in all AEO2020 cases decrease early in the projection period before increasing in the later years through 2050 as economic growth and increasing energy demand outweigh improvements in efficiency.
- In the High Economic Growth case, CO_2 emissions decrease through the late 2020s before increasing through 2050 to higher levels than in 2019.
- In the Low Economic Growth case, CO_2 emissions decline for most of the projection period and only begin to slowly increase after 2045.
- By 2050, CO_2 emissions in the High Economic Growth case are 13% higher than in the Reference case, and those in the Low Economic Growth case are 11% lower than in the Reference case.

AEO2020 energy-related CO2 emissions increase in the industrial sector, increase as a result of natural gas consumption, but remain relatively flat in other sectors and fuel types through 2050

Energy-related CO2 emissions by energy sector (AEO2020 Reference case)
billion metric tons

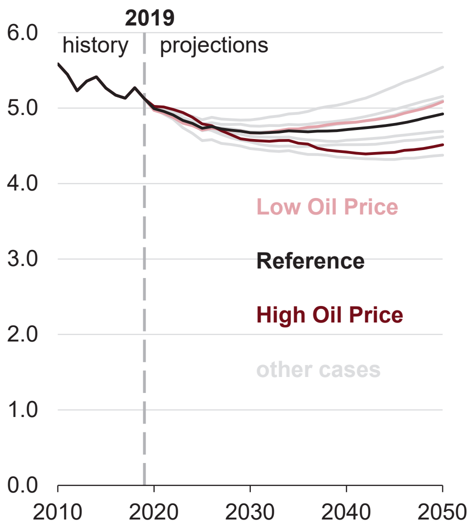


Energy-related CO2 emissions by fuel (AEO2020 Reference case)
billion metric tons

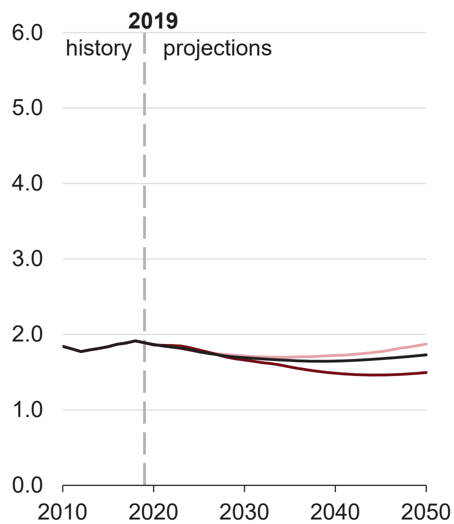


Assumptions regarding crude oil prices affect energy-related CO2 emissions in AEO2020 —

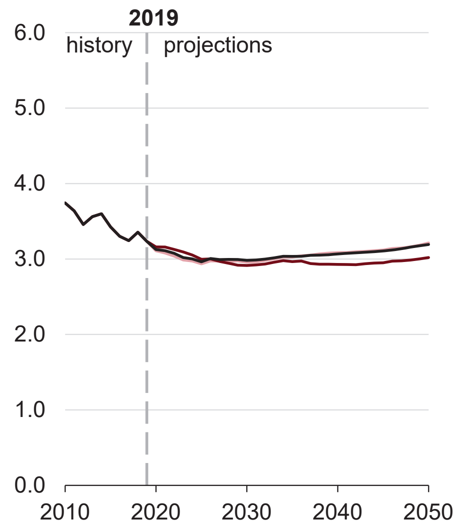
U.S. energy-related CO2 emissions
billion metric tons



Transportation sector CO2 emissions
billion metric tons



Non-transportation sectors CO2 emissions
billion metric tons

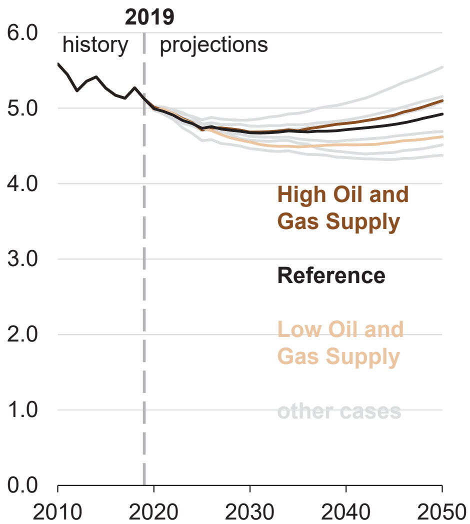


— and the oil price assumptions have the greatest effect on CO2 emissions from the transportation sector

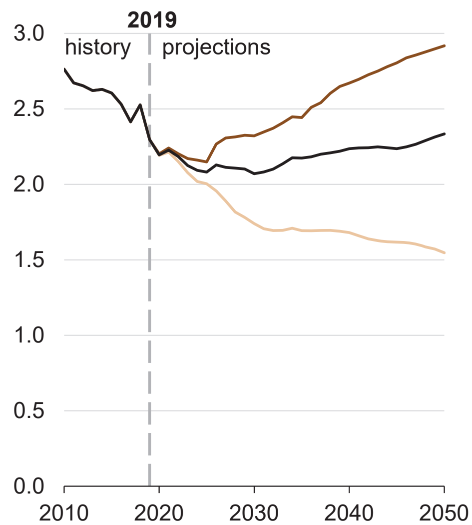
- Transportation sector emissions vary the most in the AEO2020 price cases because petroleum-related emissions dominate the transportation sector.
- In the Low Oil Price case, after an early decline, emissions increase to almost 2019 levels by 2050. Low-priced petroleum products trigger increased demand that results in greater CO2 emissions than in the Reference case.
- In the High Oil Price case, emissions decrease compared with the Reference case. Higher petroleum product prices reduce demand for petroleum products, leading to lower CO2 emissions.
- In the Low Oil Price case, transportation CO2 emissions are 1,874 million metric tons (MMmt) by 2050. In the High Oil Price case, transportation-related CO2 emissions are 1,495 MMmt.
- The industrial sector is the next most responsive sector to petroleum prices. In the Low Oil Price case, CO2 emissions from the industrial sector are 1,683 MMmt by 2050, and in the High Oil Price case, they are 1,589 MMmt.

The AEO2020 High Oil and Gas Supply and Low Oil and Gas Supply cases have different electricity generation fuel mixes than the Reference case—

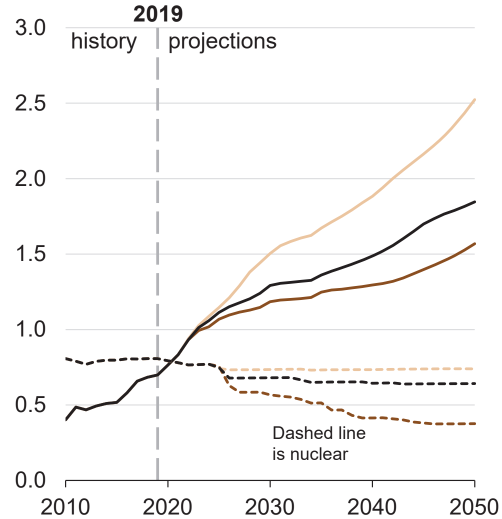
AEO2020 U.S. energy-related CO2 emissions
billion metric tons



AEO2020 fossil fuel-fired electric generation
trillion kilowatthours



AEO2020 renewables and nuclear electric generation
trillion kilowatthours



—resulting in different CO2 emissions profiles

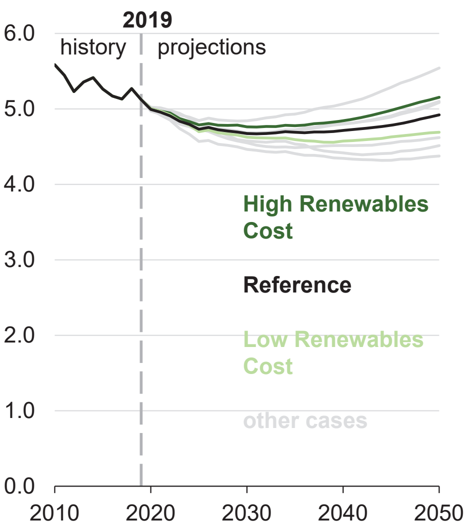
- In the AEO2020 High Oil and Gas Supply case, energy-related CO2 emissions are higher overall compared with the Reference case, as a result of increased use of natural gas consumption, primarily in the electric power sector—and to a lesser extent, the industrial sector. The relatively low natural gas prices in this case allows natural gas to compete with renewables for new electricity generation capacity. Relatively inexpensive natural gas also accelerates nuclear retirements.

- In the Low Oil and Gas Supply case, CO2 emissions are lower overall, compared with the Reference case. Energy-related CO2 emissions decrease until about 2035 as a result of retiring coal-fired power plants, and although they increase after 2035, they remain 10% lower than 2019 levels. The relatively high natural gas prices in this case lead to greater renewables penetration and fewer nuclear retirements.

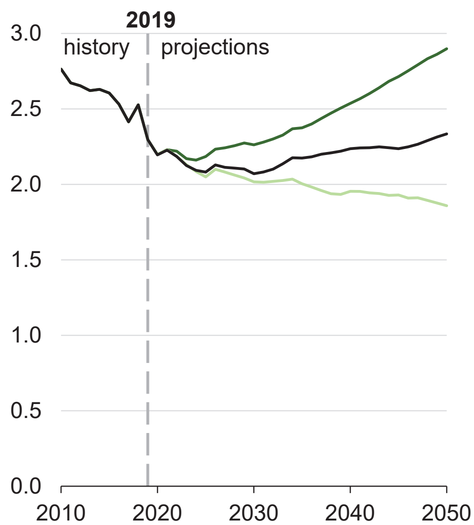
- By 2050, in the High Oil and Gas Supply case, fossil fuel-fired electric power generation is 25% higher than in the Reference case. In the Low Oil and Gas Supply case it is 34% lower than in the Reference case. The High Oil and Gas Supply case emits 5,099 MMmt CO2, and the Low Oil and Gas Supply case emits 4,620 MMmt CO2, creating a range of about 478 MMmt in CO2 emissions.

Changes in AEO2020 cost assumptions for new wind and solar projects also result in different electricity generation fuel mixes—

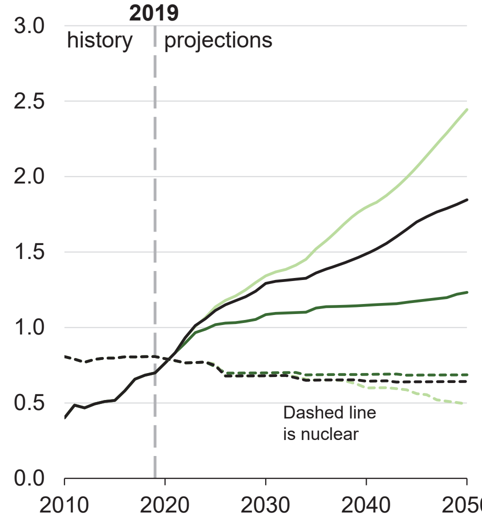
AEO2020 U.S. energy-related CO2 emissions
billion metric tons



AEO2020 fossil fuel-fired electric generation
trillion kilowatthours



AEO2020 renewables and nuclear electric generation
trillion kilowatthours



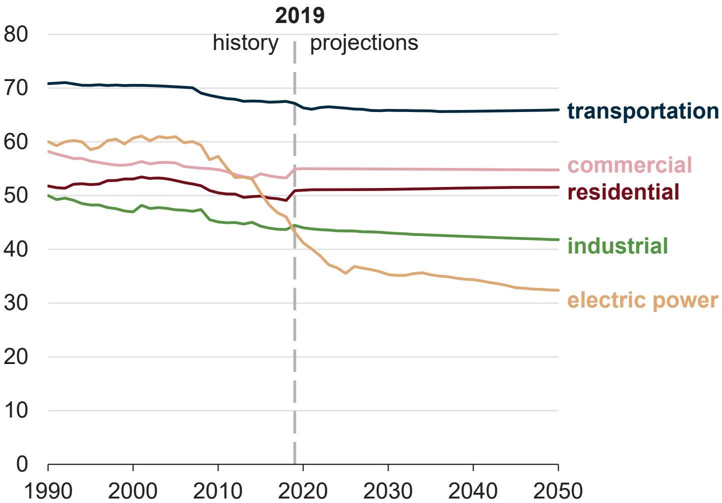
—and consequently, different energy-related carbon dioxide emission profiles

- The AEO2020 High Renewables Cost case, which assumes no further cost reductions for renewables, results in more energy-related CO2 emissions overall compared with the Reference case throughout the projection period. Until about 2030, emissions decrease as a result of retiring coal-fired generation capacity. After 2030, less penetration of renewables, increased natural gas-fired generation, and slightly fewer nuclear retirements (compared with the Reference case) lead CO2 emissions to return to nearly 2019 levels by 2050.

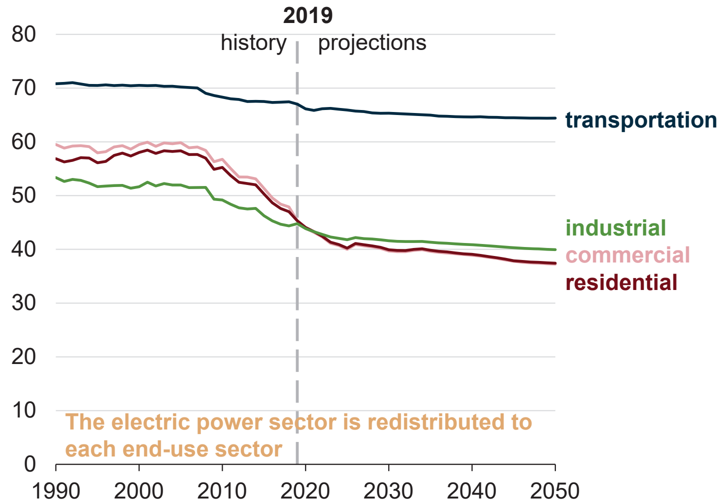
- The Low Renewables Cost case, which has sustained cost reductions for renewables through 2050, results in lower energy-related CO2 emissions overall compared with the Reference case. Increasing electricity generation from renewables leads to decreasing emissions; after 2040, total emissions increase as a result of increased energy demand in the transportation and industrial sectors that are less dependent upon electricity. However, in 2050, emissions remain 8% lower than 2019 levels.

Across end-use sectors, carbon intensity declines with changes in the fuel mix in the AEO2020 Reference case—

Carbon intensity by energy sector (AEO2020 Reference case)
metric tons of carbon dioxide per billion British thermal units



Carbon intensity by end-use sector (AEO2020 Reference case)
metric tons of carbon dioxide per billion British thermal units



—despite overall increases in energy consumption

- Carbon intensity can vary greatly depending on the mix of fuels the end-use sectors consume. Historically, the industrial sector has had the lowest carbon intensity, as measured by CO2 emissions per British thermal unit. The transportation sector historically has had the highest carbon intensity, which continues in the projection because carbon-intensive petroleum remains the dominant fuel used in vehicles throughout the projection period.

- The generation fuel mix in the electric power sector has changed since the mid-2000s; less generation is coming from high-carbon-intensive coal, and more generation is coming from natural gas and carbon-free renewables, such as wind and solar. Because of this change, the overall carbon intensity of the electric power sector declined by 30% from the mid-2000s to 2019 and is expected to continue to decline through 2050.

- If the CO2 emissions from the electricity sector in the end-use sectors that consume electricity are accounted for, carbon intensity declines to a greater degree across those sectors for all AEO2020 cases. In the Reference case, the carbon intensities of the residential and commercial sectors show no decline when their direct carbon intensities are counted from 2019 to 2050. When the electric power sector energy is distributed to the end-use sectors, the residential and commercial sectors decline by 17% and 18%, respectively, during the projection period, and the industrial sector declines by 11%. Transportation carbon intensity declines by 4%.

References

Abbreviations

AEO = Annual Energy Outlook
b = barrel(s)
BEV = battery-electric vehicle
b/d = barrels per day
bkWh = billion kilowatthours
Btu = British thermal unit(s)
CFL = compact fluorescent lamp
CHP = combined heat and power
CO2 = carbon dioxide
CPP = Clean Power Plan
EIA = U.S. Energy Information Administration
gal = gallon(s)
GDP = gross domestic product
GW = gigawatt(s)
HGL = hydrocarbon gas liquids
ITC = investment tax credit
kWh = kilowatthour(s)
LED = light-emitting diode
LNG = liquefied natural gas
MARPOL = marine pollution, the International Convention for the Prevention of Pollution from Ships
MMBtu = million British thermal units
MMst = million short tons
NEMS = National Energy Modeling System
NGPL = natural gas plant liquids
OPEC = Organization of the Petroleum Exporting Countries
PHEV = plug-in hybrid-electric vehicle
PTC = production tax credit
PV = photovoltaic
Tcf = trillion cubic feet
ZEV = zero-emission vehicle

Graph sources

Projected values are sourced from

Projections: EIA, AEO2020 National Energy Modeling System (runs: ref2020.d112119a, highprice.d112619a, lowprice.d112619a, highmacro.d112619a, lowmacro.d112619a, highogs.d112619a, lowogs.d112619a, hirencst.d1126a, lorencst.1201a)

EIA historical data are sourced from

- *Monthly Energy Review* (and supporting databases), September 2019
- Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*, July 2019

For source information for specific graphs published in this document, contact annualenergyoutlook@eia.gov.

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U.S. Energy Information Administration homepage | www.eia.gov

Short-Term Energy Outlook | www.eia.gov/steo

Annual Energy Outlook | www.eia.gov/aeo

International Energy Outlook | www.eia.gov/ieo

Monthly Energy Review | www.eia.gov/mer

Today in Energy | www.eia.gov/todayinenergy

Quantitative Profiles

Screening for "solidly liquid" stocks

17 March 2020

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What factors explain the sell-off best? Oil & liquidity

Who cares about growth, value or momentum? The bear market so far is most explained by oil and liquidity characteristics. Companies in the S&P 500 with the highest betas to oil prices significantly underperformed the S&P 500 since its peak, where oil betas were inversely correlated with peak to trough stock returns by ~40%. Similarly Altman Z-scores and credit ratings had ~25% correlations to stocks. Liquidity concerns loom large, and we here screen for the most solidly liquid companies by Altman Z-scores, Quick Ratios, Current Ratios and other measures of liquidity (see page 4).

Downturn regime; valuation extremes seen among factors

Our US Regime Indicator (Chart 5) was unchanged, with the largest deterioration in the underlying inputs coming from the declining 10-yr US Treasury yields (-35bps MoM) and widening High Yield bonds spreads (+103bp MoM, see p. 14 for the list of all inputs). Amid falling equities and rising volatility, Quality held up best during the sell-off whereas Risk and Value underperformed most. Quality (-7.3%) was the most resilient style, with three of the top five factors overall in that category (High Debt Adj'd 1-yr and 5-yr ROE and High ROA with -6.4% to -5.8% returns). Quality had best start of the year since the Global Financial Crisis, +3.4ppt ahead of the index. The bear market so far has resulted in a near-record number of factors trading at a 25%+ discount or premium to average (Chart 1).

Distressed stocks at distressed levels

As Risk and Value groups underperformed the index both in Feb (-11.7% and -12.1%, each) and YTD (-16.4% and -16.9%, each), factor valuations in these groups declined to below the Global Financial Crisis levels. Low Price companies (dollar stocks, typically the most distressed companies) declined by 13.5% in February, and now trade at all-time lows vs. High Priced stocks (Chart 6). Among Value factors, EV/EBITDA, Price / Cash Flow and Forward P/E trade at all-time lows and are most primed to snap back if a recovery begins to take shape.

Dividend growth beat high div yield, but still cheap

The recent emergency Fed cut to zero and the resulting equity tantrum highlight the continued scarcity of safe income. High Dividend Growth factor (safer yield, typically with lower payout ratios) beat High Dividend Yield – where some of these companies are likely to cut dividends - last month (-9.1% vs -11.1%) and YTD (-13.3% vs -14.5%). With Dividend Growth valuations touching all-time lows (Chart 8), this factor offers inexpensive exposure to safer yield.

Screens and performance data are available in Research Library in Excel format

Top 5 screens in February	Perf.
ROE (1-Yr Avg. Adj. by Debt)	-5.8%
ROE (5-Yr Avg. Adj. by Debt)	-6.0%
Relative Strength (10wk/40wk)	-6.3%
ROA	-6.4%
Relative Strength (30wk/75wk)	-7.0%
S&P 500 (Equal weighted)	-9.1%

Bottom 5 screens in February	Perf.
Low Price to Book Value	-14.4%
Earnings Yield	-13.7%
Low Price	-13.5%
High EPS Estimate Dispersion	-13.0%
Low Price to Cash Flow	-13.0%
S&P 500 (Equal weighted)	-9.1%

Disclaimer: The valuations and screens contained herein are useful in assessing comparative valuations and comparative earnings prospects and are not intended to recommend transactions relating to any specific security. These indicators should be used in investment decisions only with other factors including financial risk, investment risk, management strategies and operating and financial outlooks.

BofA Universe Sector/Industry Factor Evaluation (cont'd)

			Valuation Analysis								Expectation Analysis							
	# of	% Univ	Impl.	Reqd	DDM	Eqty.	BofA	P/E	Price/			Earnings (Decile)				PR 5yr	EPS Growth	
	Comp	BofA	Return	Return	Alpha	Duration	Adj ßeta	Ratio	Book	Yield	Surprise	Risk	Torp	Disp	Est. Rev.	Growth	2020E	2021E
CONSUMER STAPLES	50	6.75	9.8	8.3	1.5	34.8	0.74	18.9	4.64	2.9	6	6	4	2	5	7.5	5	7
FOOD & STAPLES RETAILING	11	1.41	9.1	8.7	0.4	41.4	0.78	18.4	4.18	1.8	5	4	4	3	5	6.4	4	7
BEVERAGES	8	1.91	9.1	7.9	1.2	36.8	0.69	23.4	6.01	2.7	7	7	4	2	5	7.4	6	9
FOOD PRODUCTS	16	0.97	10.0	8.6	1.4	33.8	0.77	16.7	2.55	2.7	6	6	4	3	5	8.7	3	7
TOBACCO	2	0.74	13.0	9.8	3.2	18.8	0.89	11.8	11.93	6.7	4	5	6	2	4	8.6	7	7
HOUSEHOLD PRODUCTS	8	1.56	9.3	7.4	1.9	37.1	0.65	21.5	6.22	2.6	8	6	5	1	3	7.1	7	7
PERSONAL PRODUCTS	5	0.17	9.3	8.9	0.4	40.8	0.80	24.2	6.86	1.4	7	3	5	4	7	10.2	5	12
HEALTH CARE	188	13.91	10.8	10.4	0.4	33.1	0.95	16.1	3.75	1.7	6	6	6	4	4	12.7	8	14
HEALTH CARE EQUIP	35	3.22	10.0	10.5	-0.5	38.5	0.96	22.7	4.11	1.0	6	6	6	3	4	14.5	14	12
HEALTH CARE PROV	37	2.67	11.9	9.9	2	30.0	0.90	12.4	2.51	1.4	5	4	7	2	4	11.9	8	13
HEALTH CARE TECH	6	0.21	10.5	11.1	-0.6	36.3	1.02	35.0	5.52	0.4	3	4	5	4	4	17.3	16	19
BIOTECH	64	2.49	11.3	11.8	-0.5	30.4	1.09	18.0	5.32	2.1	5	8	6	7	5	21.1	4	26
PHARMACEUTICALS	30	4.23	10.6	9.4	1.2	30.7	0.84	13.4	3.83	2.8	7	9	6	4	4	6.8	6	11
LIFE SCIENCES	16	1.09	9.6	12.0	-2.4	43.2	1.11	23.3	4.95	0.2	4	4	6	2	5	11.5	11	12
FINANCIALS	154	9.48	11.8	11.8	0	28.2	1.09	10.3	1.22	3.1	6	4	6	4	4	7.9	5	11
BANKS	38	3.87	12.7	12.8	-0.1	23.9	1.19	9.5	1.15	3.5	7	2	6	4	4	7.2	2	11
THRIFTS & MORTGAGE FINANCE	4	0.06	12.6	12.5	0.1	25.8	1.16	7.7	1.01	3.2	5	5	7	5	4	7.6	4	5
DIV FINANCIALS	2	0.06	14.3	13.7	0.6	21.7	1.28	5.6	0.76	2.1	5		9	3	5	19.4	9	16
CONSUMER FINANCE	9	0.68	11.4	12.3	-0.9	30.6	1.14	8.9	1.37	2.0	7	5	7	3	6	8.0	3	11
CAPITAL MARKETS	55	2.51	11.2	11.6	-0.4	29.3	1.07	12.2	1.68	2.8	4	5	6	5	3	8.6	12	13
MORTGAGE REITS	15	0.19		8.4			0.74	8.8	0.99	10.6	6	5	5	5	4	-1.3	3	5
INSURANCE	31	2.11	10.8	10.1	0.7	34.6	0.92	11.1	1.07	2.2	5	5	6	3	5	9.0	7	10
INFO TECH	158	24.16	11.0	12.0	-1	34.6	1.11	20.6	6.92	1.2	6	5	6	4	3	16.8	11	16
INTERNET SOFTWARE	1	0.04		7.3			0.64	nm		0.0	9		2	9	5	-43.4	nm	nm
IT SERVICES	37	5.49	10.6	11.1	-0.5	36.6	1.02	22.1	6.08	1.1	5	4	6	2	5	16.7	12	18
SOFTWARE	57	8.49	11.0	11.4	-0.4	35.8	1.05	29.2	10.14	0.8	4	6	6	4	3	22.1	17	15
COMMUNICA. EQUIP	9	0.79	11.6	12.3	-0.7	29.2	1.14	12.6	4.20	3.0	7	9	5	3	5	12.2	5	6
COMPUTERS & PERIPH	10	4.58	10.3	13.0	-2.7	36.7	1.21	16.8	10.36	1.3	9	2	7	4	2	10.6	11	17
ELECTR EQUIP & INSTR	16	0.54	10.8	12.3	-1.5	34.8	1.13	14.8	2.68	1.4	4	6	5	4	5	7.9	4	13
SEMICONDUCTORS	28	4.23	12.3	13.4	-1.1	28.7	1.25	16.1	4.71	2.0	7	6	6	6	3	15.8	6	16
COMMUNICATION SERVICES	57	12.44	11.0	10.5	0.5	33.8	0.96	14.6	3.34	1.1	3	6	6	6	5	14.6	15	15
DIVERSIFIED TELECOM SVS	8	1.84	11.4	8.0	3.4	24.9	0.71	10.3	1.93	5.2	6	8	5	3	4	4.7	18	7
WIRELESS TELECOM SVS	2	0.24		0.3			-0.06	65.5	1.82	0.0		8	4	9	5	7.8	19	-3
MEDIA	20	1.52	13.0	11.3	1.7	28.6	1.04	13.9	2.09	1.5	5	6	6	6	6	22.5	10	11
ENTERTAINMENT	13	1.91	9.6	11.6	-2	41.0	1.07	28.9	3.88	0.7	4	5	5	7	5	17.5	11	19
INTERACTIVE MEDIA & SVCS	14	6.94	10.9	11.0	-0.1	35.5	1.01	14.0	4.79	0.0	1	5	7	6	5	15.0	16	18
UTILITIES	57	3.61	9.3	6.8	2.5	35.0	0.59	18.0	2.14	3.3	5	5	4	2	4	5.4	6	4
ELECTRIC UTILITIES	23	2.15	9.1	6.6	2.5	35.3	0.57	17.6	2.15	3.2	5	5	4	2	4	4.6	5	2
GAS UTILITIES	8	0.14	9.2	7.5	1.7	36.5	0.66	17.9	1.93	3.0	5	4	5	2	5	6.4	10	8
MULTI-UTILITIES	15	1.06	9.2	6.9	2.3	34.7	0.60	19.1	2.10	3.7	5	5	4	2	5	4.2	2	11
WATER UTILITIES	2	0.11	8.4	6.3	2.1	42.5	0.54	29.2	3.16	1.8	5	3	4	1	6	7.6	10	13
INDEP POWER PROD & ENERGY TRAD	9	0.14	13.6	9.3	4.3	25.7	0.84	13.4	1.94	3.7	2	10	8	8	6	22.6	61	-7
REAL ESTATE	109	3.94	10.0	8.6	1.4	32.4	0.77	18.7	2.65	3.6	5	5	4	2	8	7.9	5	15
REITS	101	3.80	10.0	8.4	1.6	32.2	0.74	18.9	2.66	3.7	5	5	4	2	8	7.9	5	15
REAL ESTATE MGMT & DEV	8	0.14	10.5	14.8	-4.3	38.9	1.39	13.2	2.34	0.7		4				10.1	3	10
BofA UNIVERSE	1245	100.0	10.9	11.0	-0.1	33.2	1.01	16.9	3.12	2.0						12.7	9	14
S&P 500	505	90.79	10.9	11.0	-0.1	32.8	1.01	16.8	3.09	2.0						11.0	7	12

Source: BofA US Equity and Quant Strategy, FactSet

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Quantitative Profiles

A series of record-breaking charts

14 April 2020

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Extremes in factor valuations, volatility and dispersion

Following a significant style reversal (more below), factor volatility spiked to record levels (Chart 1). Factor valuations are also stretched — a record 80% of factors trade 25%+ away from average (Chart 4), and valuation dispersion is at an all-time high. See Chart 4 to Chart 13 for a series of record-breaking charts.

Downturn regime favors Low Risk, Quality & the Nifty 50

Our US Regime Indicator (Chart 14) is in its "Downturn" phase, with all inputs except Capacity Utilization (which has a 1-mth lag) deteriorating in March (p.10). A "Downturn" favors Quality, Low Risk and Large Caps, March's best performers: Low Beta, High Debt-Adjusted 1y ROE, and the Nifty 50 were the top 3 factors for most of last month.

Style reversal: hardest hit Risk & Value led the rebound

From the start of March to its lows on 3/23, the Equal Weighted S&P 500 index declined 30.8% and Value and Risk factors suffered their deepest losses ever with 43% and 45% declines, respectively. Once equities started bouncing back, the laggards led with strong gains from Risk (31.4%) and Value (32.1%) as of 4/13. Similarly, resilient factors on the way down, such as Momentum (24.3%) and Quality (24.0%), lagged in the bounce back.

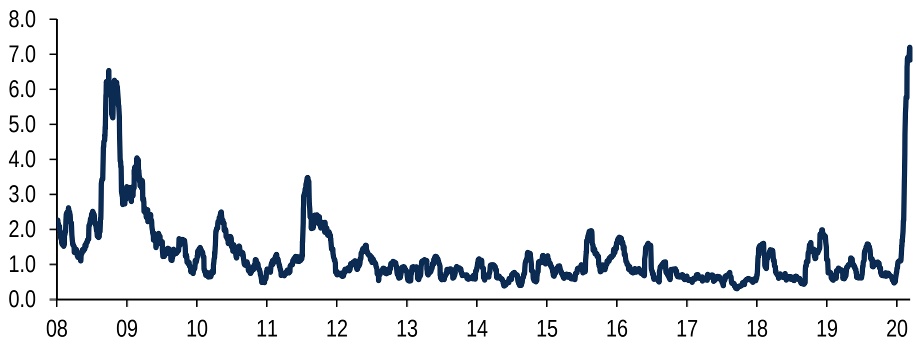
What worked during Japan's "lost decade"? Value & yield

With low rates, a US economy shifting from global (open) to local (closed), threats of deflation and what feels like a range-bound market, "Japanification of the US" concerns have resurfaced. We don't think the US will become Japan for a host of reasons (culture of immigrants, higher nominal GDP, more active shareholders, etc.). But Japan factor performance during the 90s - as rates plummeted and, after a precipitous ~60% drop in 90-92, the Nikkei-225 index remained range bound for the remainder of the decade - may be of interest. Against a stagnant backdrop, Value (Low P/E) led until 1999, when the Tech Bubble started to impact performance. Dividend Yield also outperformed amid low rates for most of the decade. And momentum lagged until late in the decade, likely hurt by a range-bound market with frequent reversals (Chart 2).

Screens and performance data are available in Research Library in Excel format

Chart 1: Extreme investing: record factor volatility

Average rolling 30-day standard deviation of returns across factors (12/2007-4/10/2020)



Source: BofA US Equity and Quant Strategy, FactSet

Top 5 screens in 1Q20	Perf.
ROE (1-Yr Avg. Adj. by Debt)	-15.7%
ROE (5-Yr Avg. Adj. by Debt)	-16.2%
ROA	-16.9%
ROC	-18.2%
Price Returns (9-Month)	-18.6%
S&P 500 (Equal weighted)	-28.1%

Bottom 5 screens in 1Q20	Perf.
High EPS Estimate Dispersion	-50.2%
Low Price to Book Value	-48.3%
Low Price to Cash Flow	-47.7%
Forward Earnings Yield	-47.3%
Earnings Yield	-47.1%
S&P 500 (Equal weighted)	-28.1%

Refer to important disclosures on page 25 to 27.

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BofA Universe Sector/Industry Factor Evaluation (cont'd)

			Valuation Analysis									Expectation Analysis						
	# of	% Univ	Impl.	Reqd	DDM	Eqty.	BofA	P/E	Price/			Earnings (Decile)				PR 5yr	EPS Growth	
	Comp	BofA	Return	Return	Alpha	Duration	Adj ßeta	Ratio	Book	Yield	Surprise	Risk	Torp	Disp	Est. Rev.	Growth	2020E	2021E
CONSUMER STAPLES	50	7.32	9.7	8.0	1.7	34.9	0.71	17.9	4.32	3.1	5	6	5	2	3	6.4	3	7
FOOD & STAPLES RETAILING	11	1.62	9.1	7.8	1.3	41.6	0.70	18.3	4.11	1.8	4	4	4	2	3	6.2	4	7
BEVERAGES	8	1.90	8.8	8.5	0.3	37.1	0.76	20.9	5.16	3.1	5	7	5	3	4	4.5	2	5
FOOD PRODUCTS	16	1.09	9.7	7.8	1.9	34.7	0.70	16.6	2.43	2.8	7	6	5	2	4	7.3	0	6
TOBACCO	2	0.78	13.6	9.4	4.2	17.2	0.85	10.9	11.55	7.3	4	5	6	2	4	8.4	5	8
HOUSEHOLD PRODUCTS	8	1.76	9.3	6.9	2.4	36.8	0.62	21.0	6.05	2.7	6	6	5	1	2	6.9	6	6
PERSONAL PRODUCTS	5	0.17	9.0	9.4	-0.4	42.2	0.85	23.6	5.82	1.6	5	3	4	5	8	7.6	-3	16
HEALTH CARE	186	15.41	10.9	9.7	1.2	32.3	0.88	15.4	3.62	1.8	5	6	7	3	3	11.4	6	15
HEALTH CARE EQUIP	35	3.46	9.9	10.2	-0.3	38.7	0.92	22.3	3.73	1.0	5	6	6	3	4	11.8	6	14
HEALTH CARE PROV	37	2.90	12.1	9.4	2.7	29.1	0.85	11.6	2.38	1.5	5	4	8	2	2	11.5	7	13
HEALTH CARE TECH	7	0.25	9.9	9.4	0.5	39.5	0.85	36.3	5.58	0.4	4	3	6	4	2	11.3	11	18
BIOTECH	60	2.82	11.5	10.8	0.7	29.1	0.98	17.3	5.33	2.1	3	8	6	5	4	17.3	3	25
PHARMACEUTICALS	30	4.78	10.6	8.6	2	30.4	0.77	13.0	3.84	2.9	5	9	7	2	3	7.0	5	12
LIFE SCIENCES	17	1.22	12.7	11.1	1.6	31.9	1.01	21.7	4.64	0.2	4	4	6	3	4	14.1	10	13
FINANCIALS	144	8.17	12.5	12.8	-0.3	25.7	1.16	8.6	0.95	3.9	5	4	5	5	5	6.7	-6	7
BANKS	38	3.24	12.4	14.1	-1.7	23.7	1.29	8.9	0.83	5.0	7	2	4	6	6	2.9	-19	0
THRIFTS & MORTGAGE FINANCE	4	0.05	14.3	14.1	0.2	20.2	1.29	5.1	0.67	4.8	5	5	7	3	3	8.0	3	5
DIV FINANCIALS	2	0.05	16.7	14.7	2	17.2	1.35	3.9	0.55	3.0	3		9	4	5	20.5	9	16
CONSUMER FINANCE	7	0.48	12.5	14.1	-1.6	26.3	1.29	6.2	0.91	3.1	2	5	6	7	8	7.9	-4	14
CAPITAL MARKETS	49	2.34	12.6	12.0	0.6	26.9	1.09	10.2	1.44	3.3	3	5	6	5	4	10.3	10	12
MORTGAGE REITS	13	0.10		12.1			1.10	4.3	0.49	11.0	5	5	7	3	2	-1.6	2	5
INSURANCE	31	1.91	12.5	11.0	1.5	27.1	1.00	8.3	0.89	2.8	4	5	7	2	3	8.7	6	10
INFO TECH	160	25.49	11.0	11.8	-0.8	34.5	1.07	19.7	6.25	1.4	6	5	6	4	3	15.6	4	20
INTERNET SOFTWARE	1	0.03		10.4			0.94	nm		0.0	6		2	10	7	0.0	nm	nm
IT SERVICES	39	5.43	10.4	11.4	-1	37.5	1.04	19.5	5.02	1.3	6	3	6	4	5	14.0	5	22
SOFTWARE	57	9.30	10.9	11.0	-0.1	35.8	1.00	27.0	9.64	0.8	3	6	6	3	2	20.5	18	14
COMMUNICA. EQUIP	9	0.90	11.7	11.1	0.6	29.0	1.01	12.3	4.09	3.0	4	9	5	3	4	11.4	4	7
COMPUTERS & PERIPH	10	4.91	10.6	12.4	-1.8	35.6	1.13	17.2	9.57	1.4	10	2	8	3	3	10.7	1	26
ELECTR EQUIP & INSTR	16	0.51	11.4	12.8	-1.4	31.8	1.17	12.8	2.16	1.7	2	6	5	5	7	7.5	-4	19
SEMICONDUCTORS	28	4.42	12.3	12.9	-0.6	28.3	1.18	15.9	4.23	2.2	8	6	6	5	3	14.6	-5	24
COMMUNICATION SERVICES	54	12.57	11.3	10.6	0.7	32.4	0.96	14.1	2.91	1.2	3	6	6	5	5	13.3	1	25
DIVERSIFIED TELECOM SVS	6	1.89	12.0	8.1	3.9	23.3	0.72	9.2	1.72	5.9	4	8	5	3	3	5.0	17	7
WIRELESS TELECOM SVS	2	0.26	12.5	1.2	11.3	29.6	0.08	58.2	1.71	0.0	1	8	5	8	4	7.6	19	-3
MEDIA	19	1.44	11.6	11.6	0	28.1	1.06	12.1	1.72	1.8	6	6	6	5	5	23.8	0	20
ENTERTAINMENT	13	2.03	10.6	11.1	-0.5	38.7	1.00	30.9	3.55	0.7	4	6	5	6	5	16.9	-5	47
INTERACTIVE MEDIA & SVCS	14	6.95	11.1	11.4	-0.3	34.5	1.03	14.0	4.14	0.0	2	5	7	5	6	12.5	-4	32
UTILITIES	56	3.72	9.6	7.2	2.4	32.9	0.64	16.0	1.87	3.7	4	5	5	2	3	5.2	0	8
ELECTRIC UTILITIES	23	2.22	9.4	7.0	2.4	33.0	0.63	15.7	1.85	3.7	4	5	5	1	2	4.1	-4	6
GAS UTILITIES	8	0.16	9.5	7.3	2.2	35.0	0.65	16.8	1.75	3.2	4	4	6	1	3	6.7	9	8
MULTI-UTILITIES	15	1.09	9.6	7.2	2.4	32.4	0.65	16.9	1.88	4.1	4	5	5	1	3	4.9	3	12
WATER UTILITIES	2	0.13	8.6	6.3	2.3	41.3	0.56	28.5	3.06	1.9	4	3	5	1	3	7.5	7	10
INDEP POWER PROD & ENERGY TRAD	8	0.13	13.5	10.8	2.7	23.9	0.98	9.8	1.50	4.3	3	10	9	7	4	22.2	65	5
REAL ESTATE	106	3.73	10.8	9.1	1.7	29.5	0.82	16.9	2.16	4.0	8	5	5	2	6	7.8	-7	9
REITS	98	3.62	10.7	8.9	1.8	29.3	0.80	17.3	2.18	4.1	8	5	5	2	6	7.7	-7	9
REAL ESTATE MGMT & DEV	8	0.11	11.5	16.8	-5.3	34.8	1.54	8.6	1.58	1.0		4			2	9.8	-4	10
BofA UNIVERSE	1222	100.0	11.0	11.0	0	32.7	1.00	17.3	2.66	2.2						11.4	-7	20
S&P 500	505	92.11	11.0	10.8	0.2	32.3	0.99	17.2	2.68	2.2						9.8	-7	17

Source: BofA US Equity and Quant Strategy, FactSet

Quantitative Profiles

Quant work says bear market rally, not a real bull

08 May 2020

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Risk-on performance, but slowing fundamentals

Economic inputs into our Regime Indicator trended lower: 2020 GDP expectation declined from 1% a month ago to -3.9% now, PMI dropped to its lowest levels since May 2009, and the earnings revision ratio hit its March 2009 lows. This might interpreted as perversely encouraging, given the last time signals were this low, the market started bottoming out. But our Regime indicator declined from -0.8 a month ago to -1.4, the bottom decile of observations (Chart 13) and still would argue for a bias toward Quality and anti-Risk. Yet, the magnitude of April's rally (the equal-wtd S&P 500 index jumped 14.6%, second best monthly performance in our history since '86 after April 2009), and Risk (+26.2%), Value (+21/0%), and Small Size (+27.7%) outperforming as Quality (+13.5%) lagged, favors further upside. The decoupling of fundamentals and markets is evident, but year-to-date (YTD), Quality (-8.0%) and Momentum (-12.8%) remain the best performing factor groups, while Value (-29.1%) and Risk (-26.1%) are lagging.

Some moderation in factor valuation extremes

Last month valuation extremes abounded, indicating that a value rally was imminent. This month we have seen these extremes subside, but Value factors remain inexpensive and neglected versus Quality and Momentum (Charts 4, 11). Quality factor valuations remain near all-time highs, and secular growth stocks (our High Projected L-T Growth factor) actually grew pricier. Low Beta stocks still trade at 2009-like premia.

No real bull until distressed equities rally

In determining whether March marked the beginning of a real bull market (like March of 2009, March of 2003 and Jan of 1991) or a bear market rally (Nov 1989, June 2000 and Dec 2008), factors can help. During the early stages of each of the prior real bull markets, our Low Price factor – read "dollar stocks", or "distressed equities" was the best performing factor, but did not lead in bear market rallies. In fact, prior bear market rallies saw mixed leadership. Since 23 March lows, Value (Price/Book and Fwd P/E) and Risk (Estimate Dispersion and Beta) have led. But the mediocre performance of Low Price stocks, i.e. distressed equities from the bottom, suggests we may want to watch this factor for signs of confirmation that this is a real bull rather than a bear rally (Table 1).

Screens and performance data are available in Research Library in Excel format

Table 1: Factor performance in prior bear market rallies and early bull markets vs today (sorted by performance)

Bear Mkt Rally 10/89-12/89	Bear Mkt Rally 05/00-08/00	Bear Mkt Rally 11/08-12/08	New Bull Mkt 12/90-02/91	New Bull Mkt 02/03-04/03	New Bull Mkt 02/09-04/09	Now 3/23 – 5/6/20
Growth	Momentum	Value	Low Price	Low Price	Low Price	Value
Neglect	Growth	Low Price	Risk	Risk	Risk	Risk
Cash Return	Risk	Risk	Quality	Value	Value	Cash Return
Risk	Quality	Cash Return	Value	Neglect	Neglect	Grth
Low Price	Cash Return	Growth	Neglect	Quality	Cash Return	Low Price
Momentum	Low Price	Quality	Growth	Growth	Growth	Quality
Quality	Value	Neglect	Cash Return	Momentum	Quality	Momentum
Value	Neglect	Momentum	Momentum	Cash Return	Momentum	Neglect

Source: FactSet, BofA US Equity & Quant Strategy

Top 5 screens in April	Perf.
High EPS Estimate Dispersion	36.3%
High Beta	30.9%
Low Price to Book Value	29.7%
Small Size	27.7%
Low Price	26.0%
S&P 500 (Equal weighted)	14.6%

Bottom 5 screens in April	Perf.
Relative Strength (5wk/30wk)	8.1%
Price Returns (3-Month)	8.5%
Price Returns (12-m + 1-m)	9.4%
Relative Strength (Price/200d MA)	9.5%
Price Returns (9-Month)	9.8%
S&P 500 (Equal weighted)	14.6%

Refer to important disclosures on page 70 to 72.

BofA Universe Sector/Industry Factor Evaluation (cont'd)

			Valuation Analysis								Expectation Analysis							
	# of	% Univ	Impl.	Reqd	DDM	Eqty.	BofA	P/E	Price/			Earnings (Decile)				PR 5yr	EPS Growth	
	Comp	BofA	Return	Return	Alpha	Duration	Adj ßeta	Ratio	Book	Yield	Surprise	Risk	Torp	Disp	Est. Rev.	Growth	2020E	2021E
CONSUMER STAPLES	51	6.90	9.5	7.5	2	36.2	0.71	20.2	4.70	2.9	6	6	6	2	3	5.1	-2	8
FOOD & STAPLES RETAILING	11	1.52	8.9	7.3	1.6	42.5	0.70	20.3	4.37	1.7	5	4	6	2	2	6.2	0	8
BEVERAGES	8	1.80	8.4	8.0	0.4	40.7	0.76	25.4	5.74	2.9	9	7	6	2	4	1.2	-12	10
FOOD PRODUCTS	17	1.05	9.5	7.5	2	36.0	0.71	18.7	2.71	2.5	7	6	6	2	3	7.0	-3	6
TOBACCO	2	0.70	12.7	8.2	4.5	18.8	0.78	11.6	10.99	7.2	2	5	7	2	4	6.3	0	8
HOUSEHOLD PRODUCTS	8	1.66	9.0	6.7	2.3	37.9	0.63	22.6	6.53	2.6	6	6	7	1	2	6.6	6	6
PERSONAL PRODUCTS	5	0.17	8.8	9.0	-0.2	40.4	0.86	26.4	6.48	0.5	3	3	5	6	6	7.0	-4	13
HEALTH CARE	188	15.45	10.3	9.4	0.9	35.0	0.90	18.2	3.62	1.6	5	6	7	3	4	11.2	0	17
HEALTH CARE EQUIP	36	3.51	9.5	9.8	-0.3	41.1	0.94	27.4	4.08	0.9	4	6	6	4	5	13.3	-2	16
HEALTH CARE PROV	37	2.92	11.3	9.3	2	32.1	0.89	13.6	2.64	1.2	7	4	9	2	3	10.6	1	17
HEALTH CARE TECH	7	0.26	9.1	9.1	0	43.5	0.87	47.9	6.70	0.3	6	3	7	4	3	28.2	0	20
BIOTECH	63	2.83	10.8	10.4	0.4	31.7	1.00	19.4	6.07	1.9	4	8	7	5	3	15.2	3	25
PHARMACEUTICALS	28	4.69	10.1	8.3	1.8	32.9	0.80	15.0	2.25	2.6	6	9	7	2	3	6.4	0	13
LIFE SCIENCES	17	1.25	11.9	10.7	1.2	35.4	1.03	28.1	5.57	0.2	6	4	7	3	4	12.4	-3	16
FINANCIALS	144	7.95	11.3	11.8	-0.5	29.8	1.14	13.1	1.01	3.5	5	4	4	4	6	-0.6	-36	23
BANKS	38	3.13	11.7	12.8	-1.1	26.5	1.24	14.7	0.91	4.5	4	2	3	6	8	-3.0	-52	36
THRIFTS & MORTGAGE FINANCE	4	0.05	13.6	12.9	0.7	21.9	1.25	7.6	0.76	4.2	7	5	5	5	5	7.9	-32	53
DIV FINANCIALS	2	0.05		13.3			1.29	5.3	0.66	2.5	5		7	2	4	13.0	-4	16
CONSUMER FINANCE	7	0.48	8.5	13.3	-4.8	48.5	1.29	16.5	1.11	2.7	3	5	3	7	9	-4.9	-73	78
CAPITAL MARKETS	49	2.33	10.2	11.3	-1.1	36.2	1.09	15.7	1.50	2.9	7	5	5	4	5	-2.0	-22	12
MORTGAGE REITS	13	0.11		12.2			1.18	10.5	0.68	10.3	8	5	3	7	5	-2.2	-57	65
INSURANCE	31	1.79	11.4	10.0	1.4	30.2	0.96	9.5	0.89	2.7	5	5	7	2	4	6.3	-2	10
INFO TECH	158	25.58	10.5	11.0	-0.5	36.9	1.06	22.9	7.30	1.2	5	5	7	3	3	15.1	1	22
INTERNET SOFTWARE	1	0.03		11.0			1.06	nm		0.0	6		4	10	5	0.0	nm	nm
IT SERVICES	38	5.54	9.7	11.0	-1.3	40.5	1.06	24.6	5.88	1.1	6	4	7	4	5	12.2	-6	23
SOFTWARE	58	9.32	10.4	10.4	0	38.2	1.00	31.0	10.68	0.7	2	6	8	2	2	20.1	16	14
COMMUNICA. EQUIP	9	0.86	11.3	10.2	1.1	30.8	0.98	13.8	4.48	2.8	4	9	5	3	3	11.3	3	7
COMPUTERS & PERIPH	10	4.95	10.1	11.5	-1.4	37.7	1.11	19.5	13.03	1.2	10	2	8	3	3	10.5	-2	31
ELECTR EQUIP & INSTR	16	0.52	10.5	12.1	-1.6	37.3	1.17	16.8	2.62	1.4	4	6	5	4	6	6.3	-20	33
SEMICONDUCTORS	26	4.36	11.8	12.0	-0.2	29.8	1.16	17.9	4.87	1.9	7	6	7	4	3	15.0	-5	22
COMMUNICATION SERVICES	53	12.52	10.6	10.4	0.2	36.2	1.00	17.0	3.38	1.1	3	6	6	4	5	11.7	-7	29
DIVERSIFIED TELECOM SVS	6	1.76	11.5	7.5	4	25.1	0.71	10.4	1.87	5.6	4	7	5	2	3	4.3	8	6
WIRELESS TELECOM SVS	1	0.12	12.3	5.5	6.8	30.4	0.51	16.9	2.61	0.0	1	8	3	9	8	17.5	20	21
MEDIA	19	1.42	12.6	10.9	1.7	28.7	1.05	16.0	1.93	1.6	7	6	6	4	6	21.2	-20	36
ENTERTAINMENT	13	2.00	10.4	10.5	-0.1	39.8	1.01	37.9	3.97	0.7	5	5	6	6	5	14.9	-17	59
INTERACTIVE MEDIA & SVCS	14	7.21	10.0	11.0	-1	39.8	1.06	17.2	4.79	0.0	1	5	7	4	6	10.7	-9	34
UTILITIES	56	3.39	9.5	6.6	2.9	33.4	0.63	16.7	1.98	3.6	5	5	7	1	2	5.1	-1	7
ELECTRIC UTILITIES	23	2.00	9.4	6.4	3	33.2	0.60	16.2	1.95	3.6	5	5	7	1	2	3.9	-5	5
GAS UTILITIES	8	0.14	9.5	6.8	2.7	34.5	0.64	17.5	1.82	3.1	4	4	8	1	3	6.3	8	9
MULTI-UTILITIES	15	1.02	9.4	6.8	2.6	33.5	0.65	18.0	2.01	3.8	6	5	7	1	2	4.6	1	10
WATER UTILITIES	2	0.12	8.6	5.7	2.9	41.1	0.53	28.9	3.12	1.9	4	3	7	1	2	7.5	6	12
INDEP POWER PROD & ENERGY TRAD	8	0.12	13.3	10.1	3.2	25.1	0.97	10.8	1.68	3.9	3	10	9	7	5	23.9	80	9
REAL ESTATE	106	3.57	10.0	8.6	1.4	33.2	0.82	20.0	2.30	3.9	8	5	6	2	4	6.5	-17	13
REITS	98	3.46	10.0	8.5	1.5	33.2	0.81	20.0	2.32	4.0	8	5	6	2	4	6.5	-15	11
REAL ESTATE MGMT & DEV	8	0.10	11.2	15.1	-3.9	35.7	1.47	19.0	1.76	0.9		4			2	7.1	-60	69
BofA UNIVERSE	1218	100.0	10.4	10.5	-0.1	35.8	1.01	22.8	3.00	1.9						10.4	-20	28
S&P 500	505	91.46	10.4	10.3	0.1	35.3	0.99	22.2	2.98	2.0						8.8	-19	25

Source: BofA US Equity and Quant Strategy, FactSet

Movements in S&P 500, DJU, & VIX

	Percentage Change		
Time Period (Year 2020)	CBOE Volatility Index (VIX)	S&P 500 (S&P500)	Dow Jones Utility Average (DJU)
Jan 2 - May 29	54.7%	-7.0%	-7.4%
Feb 3 - May 29	34.7%	-6.7%	-16.6%
Feb 3 - Apr 30	47.4%	-11.6%	-20.9%
Feb 19 - June 8	44.3%	-4.8%	-12.1%

Stock Prices/Index			
Date	CBOE Volatility Index (VIX)	S&P 500 (S&P500)	Dow Jones Utility Average (DJU)
1/2/2020	12.47	3,257.85	866.82
1/3/2020	14.02	3,234.85	867.44
1/6/2020	13.85	3,246.28	870.03
1/7/2020	13.79	3,237.18	868.60
1/8/2020	13.45	3,253.05	868.91
1/9/2020	12.54	3,274.70	872.65
1/10/2020	12.56	3,265.35	874.10
1/13/2020	12.32	3,288.13	879.69
1/14/2020	12.39	3,283.15	882.07
1/15/2020	12.42	3,289.29	895.82
1/16/2020	12.32	3,316.81	900.42
1/17/2020	12.10	3,329.62	908.30
1/21/2020	12.85	3,320.79	917.10
1/22/2020	12.91	3,321.75	919.96
1/23/2020	12.98	3,325.54	928.57
1/24/2020	14.56	3,295.47	931.94
1/27/2020	18.23	3,243.63	929.65
1/28/2020	16.28	3,276.24	933.09
1/29/2020	16.39	3,273.40	935.10
1/30/2020	15.49	3,283.66	943.03
1/31/2020	18.84	3,225.52	938.57

Movements in S&P 500, DJU, & VIX

2/3/2020	17.97	3,248.92	940.67
2/4/2020	16.05	3,297.59	930.34
2/5/2020	15.15	3,334.69	934.85
2/6/2020	14.96	3,345.78	935.16
2/7/2020	15.47	3,327.71	931.83
2/10/2020	15.04	3,352.09	934.97
2/11/2020	15.18	3,357.75	938.48
2/12/2020	13.74	3,379.45	938.12
2/13/2020	14.15	3,373.94	947.38
2/14/2020	13.68	3,380.16	955.35
2/18/2020	14.83	3,370.29	960.89
2/19/2020	14.38	3,386.15	950.01
2/20/2020	15.56	3,373.23	952.40
2/21/2020	17.08	3,337.75	948.74
2/24/2020	25.03	3,225.89	935.91
2/25/2020	27.85	3,128.21	915.77
2/26/2020	27.56	3,116.39	906.97
2/27/2020	39.16	2,978.76	865.47
2/28/2020	40.11	2,954.22	839.96
3/2/2020	33.42	3,090.23	886.52
3/3/2020	36.82	3,003.37	877.25
3/4/2020	31.99	3,130.12	926.14
3/5/2020	39.62	3,023.94	908.14
3/6/2020	41.94	2,972.37	901.70
3/9/2020	54.46	2,746.56	852.80
3/10/2020	47.30	2,882.23	860.03
3/11/2020	53.90	2,741.38	812.44
3/12/2020	75.47	2,480.64	723.88
3/13/2020	57.83	2,711.02	762.60
3/16/2020	82.69	2,386.13	678.03
3/17/2020	75.91	2,529.19	769.69
3/18/2020	76.45	2,398.10	737.25
3/19/2020	72.00	2,409.39	695.92
3/20/2020	66.04	2,304.92	646.13

Movements in S&P 500, DJU, & VIX

3/23/2020	61.59	2,237.40	610.89
3/24/2020	61.67	2,447.33	673.89
3/25/2020	63.95	2,475.56	697.76
3/26/2020	61.00	2,630.07	757.92
3/27/2020	65.54	2,541.47	758.93
3/30/2020	57.08	2,626.65	785.14
3/31/2020	53.54	2,584.59	756.16
4/1/2020	57.06	2,470.50	708.04
4/2/2020	50.91	2,526.90	729.36
4/3/2020	46.80	2,607.22	706.01
4/6/2020	45.24	2,663.68	758.06
4/7/2020	46.70	2,659.41	750.81
4/8/2020	43.35	2,749.98	789.15
4/9/2020	41.67	2,789.82	827.83
4/13/2020	41.17	2,761.63	801.39
4/14/2020	37.76	2,846.06	825.10
4/15/2020	40.84	2,783.36	796.95
4/16/2020	40.11	2,799.55	797.54
4/17/2020	38.15	2,874.56	823.98
4/20/2020	42.83	2,823.16	794.85
4/21/2020	45.41	2,736.56	780.99
4/22/2020	41.98	2,799.31	804.41
4/23/2020	41.38	2,797.80	790.75
4/24/2020	35.93	2,836.74	795.09
4/27/2020	33.29	2,852.89	805.80
4/28/2020	33.57	2,863.39	804.93
4/29/2020	31.23	2,939.51	798.48
4/30/2020	34.15	2,912.43	778.29

Movements in S&P 500, DJU, & VIX

5/1/2020	37.19	2,830.17	759.08
5/4/2020	35.97	2,842.74	767.37
5/5/2020	33.61	2,868.44	773.21
5/6/2020	34.12	2,848.42	746.35
5/7/2020	31.44	2,881.19	751.97
5/8/2020	27.98	2,902.88	764.11
5/11/2020	27.57	2,930.19	761.83
5/12/2020	33.04	2,870.12	753.30
5/13/2020	35.28	2,820.00	747.54
5/14/2020	32.61	2,852.50	754.78
5/15/2020	31.89	2,863.70	744.49
5/18/2020	29.30	2,953.91	773.18
5/19/2020	30.53	2,922.94	761.40
5/20/2020	27.99	2,971.61	761.59
5/21/2020	29.53	2,948.51	754.02
5/22/2020	28.16	2,955.45	763.93
5/26/2020	28.01	2,991.77	769.03
5/27/2020	27.62	3,036.13	777.69
5/28/2020	28.59	3,029.73	800.80
5/29/2020	27.51	3,044.31	806.92
6/1/2020	28.23	3,055.73	815.33
6/2/2020	26.84	3,080.82	820.40
6/3/2020	25.66	3,122.87	831.27
6/4/2020	25.81	3,112.35	814.06
6/5/2020	24.52	3,193.93	826.52
6/8/2020	25.81	3,232.39	847.26

VALUE LINE

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CAPITAL STRUCTURE AND CORPORATE FINANCING DECISIONS

Theory, Evidence, and Practice

H. Kent Baker and Gerald S. Martin

The Robert W. Kolb Series in Finance

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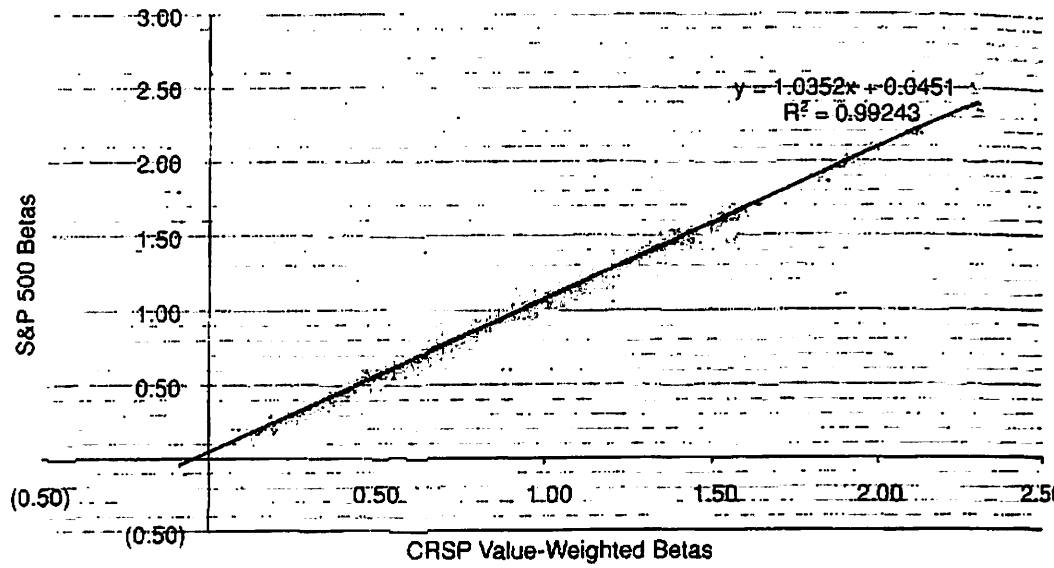

Exhibit 11.4 Plot of Historical Betas Using Two Different Value Weighted Market Indices
Note: This exhibit plots the relationship between two sets of beta estimates for S&P 500 companies using five years of historic data. Betas using the S&P 500 Index as a proxy for the market are plotted on the vertical axis. Betas using the CRSP Value Weighted Index as a proxy for the market are plotted on the horizontal axis. The exhibit also reports the results of regression analysis of the two sets of betas where y represents the vertical axis and x the horizontal axis.

On the other hand, as illustrated in Exhibit 11.4 both the value-weighted CRSP index and the S&P 500 (also value weighted) yield very similar beta estimates. These sample results illustrate the importance of choosing a value-weighted index (theory's suggestion) in estimating historic betas. The choice among broadly diversified value weighted indices is less critical. We adopt historic betas using the S&P 500 to estimate capital costs.

Historic betas do not, however, mirror those from Value Line. Exhibit 11.3 shows that Value Line betas have much less cross-sectional variation than the historic figures. This comes as no surprise given that historic estimates, unlike Value Line's approach, involve no input from analysts. Value Line's adjustments also appear informed by more than the type of simple smoothing done by Bloomberg, which uses the following formula: adjusted beta = historic beta (0.67) + 0.33. Exhibit 11.5 plots the distribution for historic, Value Line, and adjusted betas using Bloomberg's formula applied to the historic betas. Exhibit 11.5 conveys a key message for analysts: be wary of blindly using historic betas from individual company data. The tails of the distribution for historic betas contain significant measurement error. A clear advantage of Value Line betas (or those from other providers who do more than just historical regressions) is that they reflect professional judgment and attention to statistical detail. Moreover, they are data directly available to and used by investors. The objective is to capture investors' views of future risk. As various estimates of WACC are presented, the difference that the choice of beta makes, including using industry averages to reduce measurement error, is examined.

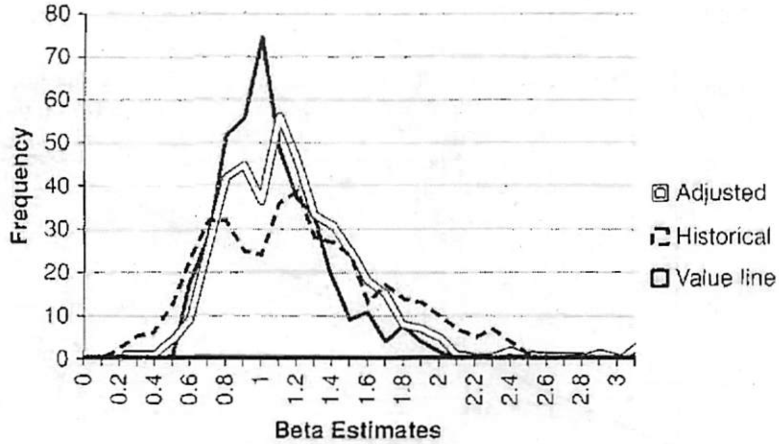

Exhibit 11.5 Frequency Distribution of Value Line, Historic, and Adjusted Historic Betas
Note: The exhibit plots the frequency of betas across the sample firms using different estimation methods. Historical betas use five years of data with the S&P 500 index as a proxy for the market. Adjusted betas are historical betas converted using the Bloomberg adjustment discussed in the text. Value Line betas come from Value Line.

THREE APPROACHES TO USING DATA FROM COMPARABLE FIRMS

Recognizing that measurement error is a fact of life, good practice in cost of capital estimation calls for gathering data on comparable firms. A recommended approach is to match firm on business risk and to look at capital structure and size. An in-depth treatment would arm the analyst with details of each company's businesses. This chapter uses all firms in an industry. The analysis focuses on three methods of estimating a company's WACC, two of which take advantage of data from other firms comparable in risk to the company.

"Single" Company Estimates of WACC

An initial step is to calculate a "single company" WACC based solely on data for the company. This may be the analyst's only resort if no good comparables can be found. As always, the most difficult ingredient to estimate is the cost of equity even if adopting the CAPM. Using Equations 11.1 and 11.2, a single company WACC is estimated for each firm in the sample. As a point of reference, the calculations for FMG earlier in the chapter roughly parallel the average characteristics of the sample firms. For instance, the average debt weight across companies was 0.27.

Industry Average WACC

Many analysts stop with a standalone calculation, but this is not advisable. Much can be learned from the other companies. One straightforward step is to calculate a single company WACC for each firm and then average across the industry. This average helps mollify the impacts of measurement error. Moreover,

FEDERAL RESERVE press release

For release at 10 a.m. EST   March 3, 2020

The fundamentals of the U.S. economy remain strong. However, the coronavirus poses evolving risks to economic activity. In light of these risks and in support of achieving its maximum employment and price stability goals, the Federal Open Market Committee decided today to lower the target range for the federal funds rate by 1/2 percentage point, to 1 to 1-1/4 percent. The Committee is closely monitoring developments and their implications for the economic outlook and will use its tools and act as appropriate to support the economy.

Voting for the monetary policy action were Jerome H. Powell, Chair; John C. Williams, Vice Chair; Michelle W. Bowman; Lael Brainard; Richard H. Clarida; Patrick Harker; Robert S. Kaplan; Neel Kashkari; Loretta J. Mester; and Randal K. Quarles.

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For media inquiries, call 202-452-2955.

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 3, 2020:

- The Board of Governors of the Federal Reserve System voted unanimously to set the interest rate paid on required and excess reserve balances at 1.10 percent, effective March 4, 2020.

- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

> "Effective March 4, 2020, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 1 to 1-1/4 percent. In light of recent and expected increases in the Federal Reserve's non-reserve liabilities, the Committee directs the Desk to continue purchasing Treasury bills at least into the second quarter of 2020 to maintain over time ample reserve balances at or above the level that prevailed in early September 2019. The Committee also directs the Desk to continue conducting term and overnight repurchase agreement operations at least through April 2020 to ensure that the supply of reserves remains ample even during periods of sharp increases in non-reserve liabilities, and to mitigate the risk of money market pressures that could adversely affect policy implementation. In addition, the Committee directs the Desk to conduct overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 1.00 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.
>
> The Committee directs the Desk to continue rolling over at auction all principal payments from the Federal Reserve's holdings of Treasury securities and to continue reinvesting all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month. Principal payments from agency debt and agency mortgage-backed securities up to $20 billion per month will continue to be reinvested in Treasury securities to roughly match the maturity composition of Treasury securities outstanding; principal payments in excess of $20 billion per month will continue to be reinvested in agency mortgage-backed securities. Small deviations from these amounts for operational reasons are acceptable.

> The Committee also directs the Desk to engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/2 percentage point decrease in the primary credit rate to 1.75 percent, effective March 4, 2020. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Minneapolis and New York.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

FEDERAL RESERVE press release

For release at 5 p.m. EDT March 15, 2020

The coronavirus outbreak has harmed communities and disrupted economic activity in many countries, including the United States. Global financial conditions have also been significantly affected. Available economic data show that the U.S. economy came into this challenging period on a strong footing. Information received since the Federal Open Market Committee met in January indicates that the labor market remained strong through February and economic activity rose at a moderate rate. Job gains have been solid, on average, in recent months, and the unemployment rate has remained low. Although household spending rose at a moderate pace, business fixed investment and exports remained weak. More recently, the energy sector has come under stress. On a 12-month basis, overall inflation and inflation for items other than food and energy are running below 2 percent. Market-based measures of inflation compensation have declined; survey-based measures of longer-term inflation expectations are little changed.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The effects of the coronavirus will weigh on economic activity in the near term and pose risks to the economic outlook. In light of these developments, the Committee decided to lower the target range for the federal funds rate to 0 to 1/4 percent. The Committee expects to maintain this target range until it is confident that the economy has weathered recent events and is on track to achieve its maximum employment and price stability goals. This action will help support economic activity, strong labor market conditions, and inflation returning to the Committee’s symmetric 2 percent objective.

The Committee will continue to monitor the implications of incoming information for the economic outlook, including information related to public health, as well as global developments and muted inflation pressures, and will use its tools and act as appropriate to support the economy. In determining the timing and size of future adjustments to the stance of monetary policy, the Committee will assess realized and expected economic conditions relative to its maximum employment objective and its symmetric 2 percent inflation objective. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments.

The Federal Reserve is prepared to use its full range of tools to support the flow of credit to households and businesses and thereby promote its maximum employment and price stability goals. To support the smooth functioning of markets for Treasury securities and agency mortgage-backed securities that are central to the flow of credit to households and businesses, over coming months the Committee will increase its holdings of Treasury securities by at least $500 billion and its holdings of agency mortgage-backed securities by at least $200 billion. The Committee will also reinvest all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities. In addition, the Open Market Desk has recently expanded its overnight and term repurchase agreement operations. The Committee will continue to closely monitor market conditions and is prepared to adjust its plans as appropriate.

Voting for the monetary policy action were Jerome H. Powell, Chair; John C. Williams, Vice Chair; Michelle W. Bowman; Lael Brainard; Richard H. Clarida; Patrick Harker; Robert S. Kaplan; Neel Kashkari; and Randal K. Quarles. Voting against this action was Loretta J. Mester, who was fully supportive of all of the actions taken to promote the smooth functioning of markets and the flow of credit to households and businesses but preferred to reduce the target range for the federal funds rate to 1/2 to 3/4 percent at this meeting.

In a related set of actions to support the credit needs of households and businesses, the Federal Reserve announced measures related to the discount window, intraday credit, bank capital and liquidity buffers, reserve requirements, and—in coordination with other central banks—the U.S. dollar liquidity swap line arrangements. More information can be found on the Federal Reserve Board's website.

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For media inquiries, call 202-452-2955.

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 15, 2020**:**

- The Board of Governors of the Federal Reserve System voted unanimously to set the interest rate paid on required and excess reserve balances at 0.10 percent, effective March 16, 2020.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective March 16, 2020, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 0 to 1/4 percent. The Committee directs the Desk to increase over coming months the System Open Market Account holdings of Treasury securities and agency mortgage-backed securities (MBS) by at least $500 billion and by at least $200 billion, respectively. The Committee instructs the Desk to conduct these purchases at a pace appropriate to support the smooth functioning of markets for Treasury securities and agency MBS.

  The Committee also directs the Desk to continue conducting term and overnight repurchase agreement operations to ensure that the supply of reserves remains ample and to support the smooth functioning of short-term U.S. dollar funding markets. In addition, the Committee directs the Desk to conduct overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 0.00 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.

  The Committee directs the Desk to continue rolling over at auction all principal payments from the Federal Reserve's holdings of Treasury securities and to reinvest all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month in agency mortgage-backed securities. Small deviations from these amounts for operational reasons are acceptable.

  The Committee also directs the Desk to engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions.

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1-1/2 percentage point decrease in the primary credit rate to 0.25 percent, effective March 16, 2020. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Minneapolis and New York.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

UTILITY STOCKS AND THE SIZE EFFECT: AN EMPIRICAL ANALYSIS

Annie Wong*

I. Introduction

The objective of this study is to examine whether the firm size effect exists in the public utility industry. Public utilities are regulated by federal, municipal, and state authorities. Every state has a public service commission with board and varying powers. Often their task is to estimate a fair rate of return to a utility's stockholders in order to determine the rates charged by the utility. The legal principles underlying rate regulation are that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks," and that the return to a utility should be sufficient to "attract capital and maintain credit worthiness." However, difficulties arise from the ambiguous interpretation of the legal definition of *fair and reasonable rate of return* to an equity owner.

Some finance researchers have suggested that the Capital Asset Pricing Model (CAPM) should be used in rate regulation because the CAPM beta can serve as a risk measure, thus making risk comparisons possible. This approach is consistent with the spirit of a Supreme Court ruling that equity owners sharing similar level of risk should be compensated by similar rate of return.

The empirical studies of Banz (1981) and Reinganum (1981) showed that small firms tend to earn higher returns than large firms after adjusting for beta. This phenomenon leads to the proposition that firm size is a proxy for omitted risk factors in determining stock returns. Barry and Brown (1984) and Brauer (1986) suggested that the omitted risk factor could be the differential information environment between small and large firms. Their argument is based on the fact that investors often have less publicly available information to assess the future cash flows of small firms than that of large firms. Therefore, an additional risk premium should be included to determine the appropriate rate of return to shareholders of small firms.

The samples used in prior studies are dominated by industrial firms, no one has examined the size effect in public utilities. The objective of this study is to extend the empirical findings of the existing studies by investigating whether the size effect is also present in the utility industry. The findings of this study have important implications for investors, public utility firms, and state regulatory agencies. If the size effect does exist in the utility industry, this would suggest that the size factor should be considered when the CAPM is being used to determine the fair rate of return for public utilities in regulatory proceedings.

II. Information Environment of Public Utilities

In general, utilities differ from industriales in that utilities are heavily regulated and they follow similar accounting procedures. A public utility's financial reporting is mainly regulated by the Securities and Exchange Commission (SEC) and the Federal Energy Regulatory Commission (FERC). Under the Public Utility Holding Company Act of 1935, the SEC is empowered to regulate the holding company systems of electric and gas utilities. The Act requires registration of public utility holding companies with the SEC. Only under strict conditions would the purchase, sale or issuance of securities by these holding companies be permitted. The purpose of the Act is to keep the SEC and investors informed of the financial conditions of these firms. Moreover, the FERC is in charge of the interstate operations of electric and gas companies. It requires utilities to follow the accounting procedures set forth in its Uniform Systems of Accounts. In particular, electric and gas utilities must request their Certified Public Accountants to certify that certain schedules in the financial reports are in conformity with the Commission's accounting requirements. These detailed reports are submitted annually and are open to the public.

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The FERC requires public utilities to keep accurate records of revenues, operating costs, depreciation expenses, and investment in plant and equipment. Specific financial accounting standards for these purposes are also issued by the Financial Accounting Standards Board (FASB). Uniformity is required so that utilities are not subject to different accounting regulations in each of the states in which they operate. The ultimate objective is to achieve comparability in financial reporting so that factual matters are not hidden from the public view by accounting flexibility.

Other regulatory reports tend to provide additional financial information about utilities. For example, utilities are required to file the FERC Form No. 1 with the state commission. This form is designed for state commissions to collect financial and operational information about utilities, and serves as a source for statistical reports published by state commissions.

Unlike industriales, a utility's earnings are predetermined to a certain extent. Before allowed earnings requests are approved, a utility's performance is analyzed in depth by the state commission, interest groups, and other witnesses. This process leads to the disclosure of substantial amount of information.

III. Hypothesis and Objective

Due to the Act of 1935, the Uniform Systems of Accounts, the uniform disclosure requirements, and the predetermined earnings, all utilities are reasonably homogeneous with respect to the information available to the public. Barry and Brown (1984) and Brauer (1986) suggested that the difference of risk-adjusted returns between small and large firms is due to their differential information environment. Assuming that the differential information hypothesis is true, then uniformity of information availability among utility firms would suggest that the size effect should not be observed in the public utility industry. The objective of this paper is to provide a test of the size effect in public utilities.

IV. Methodology

1. Sample and Data

To test for the size effect, a sample of public utilities and a sample of industriales matched by equity value are formed so that their results can be compared. Companies in both samples are listed on the Center for Research in Security Prices (CRSP) Daily and Monthly Returns files. The utility sample includes 152 electric and gas companies. For each utility in the sample, two industrial firms with similar firm size (one is slightly larger and the other is slightly smaller than the utility) are selected. Thus, the industrial sample includes 304 non-regulated firms.

The size variable is defined as the natural logarithm of market value of equity at the beginning of each year. Both the equally-weighted and value-weighted CRSP indices are employed as proxies for the market returns. Daily, weekly and monthly returns are used. The Fama-MacBeth (1973) procedure is utilized to examine the relation between risk-adjusted returns and firm size.

2. Research Design

All utilities in the sample are ranked according to the equity size at the beginning of the year, and the distribution is broken down into deciles. Decile one contains the stocks with the lowest market values while decile ten contains those with the highest market values. These portfolios are denoted by MV_1, MV_2, …, and MV_{10}, respectively.

The combinations of the ten portfolios are updated annually. In the year after a portfolio is formed, equally-weighted portfolio returns are computed by combining the returns of the component stocks within the portfolio. The betas for each portfolio at year t, $\hat{\beta}_{pt}$'s, are estimated by regressing the previous five years of portfolio returns on market returns:

$$\tilde{R}_{pt} = \alpha_p + \hat{\beta}_{pt}\tilde{R}_{mt} + \tilde{U}_{pt} \qquad (1)$$

where

R_{pt} = periodic return in year t on portfolio p

R_{mt} = periodic market return in year t

U_{pt} = disturbance term.

Banz (1981) applied both the ordinary and generalized least squares regressions to estimate β; and concluded that the results are essentially identical (p.8). Since adjusting for heteroscedasticity does not necessarily lead to more efficient estimators, the ordinary least squares procedures are used in this study to estimate β in equation (1).

The following cross-sectional regression is then run for the portfolios to estimate γ_{it}, i = 0, 1, and 2:

$$R_{pt} = \gamma_{0t} + \gamma_{1t}\hat{\beta}_{pt} + \gamma_{2t}\hat{S}_{pt} + U_{pt} \qquad (2)$$

where

$\hat{\beta}_{pt}$ = estimated beta for portfolio p at year t, t=1968, ..., 1987

$\hat{S}_{pt}$ = mean of the logarithm of firm size in portfolio p at the beginning of year t

U_{pt} = disturbance term.

Depending on whether daily, weekly or monthly returns are used, a portfolio's average return changes periodically while its beta and size only change once a year. The γ_1 and γ_2 coefficients are estimated over the following four subperiods: 1968-72, 1973-77, 1978-82 and 1983-1987. If portfolio betas can fully account for the differences in returns, one would expect the average coefficient for the beta variable to be positive and for the size variable to be zero. A t-statistic will be used to test the hypothesis. The coefficients of a matched sample are also examined so that the results between industrial and utility firms can be compared.

V. Analysis of Results

1. Equity Value of the Utility Portfolios

The mean equity values of the ten size-based utility portfolios are reported in Table 1. Panels A and B present the average firm size of these portfolios at the beginning and end of the test period, 1968-1987. The first interesting observation from Table 1 is that the difference in magnitude between the smallest and the largest market value utility portfolios is tremendous. In Panel A, the average size of MV_1 is about \$31 million while that of MV_{10} is over \$1.4 billion. In Panel B, that is twenty years later, they are \$62 million and \$5.2 billion, respectively. Another interesting finding is that there is a substantial increase in average firm size from MV_9 to MV_{10}. Since these two findings are consistent over the entire test period, the average portfolio market values for interim years are not reported. These results are similar to the empirical evidence provided by Reinganum (1981).

The utility sample in this study contains 152 firms whereas Reinganum's sample contains 535 firms that are mainly industrial companies. Two conclusions may be drawn from the results of the Reinganum study and this one. First, utilities and industriales are similar in the sense that their market values vary over a wide spectrum. Second, the fact that there is a huge jump in firm size from MV_9 to MV_{10} indicates that the distribution of firm size is positively skewed. To correct for the skewness problem, the natural logarithm of the mean equity value of each portfolio is calculated. This variable is then used in later regressions instead of the actual mean equity value.

2. Betas of the Utility and Industrial Samples

The betas based on monthly, weekly and daily returns are reported for the utility and industrial samples. For simplicity, they will be referred to as monthly, weekly, and daily betas. In all cases, five years of returns are used to estimate the systematic risk. The betas estimated over the 1963-67 time period are used to proxy for the betas in 1968, which is the beginning of the test period. By the same token, the betas obtained from the time period 1982-86 are used as proxies for the betas in 1987, which is the end of the test period.

The betas from using the equally-weighted and value-weighted indices are calculated in order to check whether the results are affected by the choice of market index. Since the results are similar, only those obtained from the equally-weighted index are reported and analyzed.

Table 2 reports the monthly, weekly and daily betas of the two samples at the beginning and end of the test period. Panel A shows the various betas of the industrial portfolios. Two conclusions may be drawn. First, in the 1960's, smaller market value portfolios tend to have relatively larger betas. This is consistent with the empirical findings by Banz (1981) and Reinganum (1981). Second, this trend seems to vanish in the 1980's, especially when weekly and daily returns are used.

The betas of the utility portfolios are presented in Panel B. The table shows that none of the utility betas are greater than 0.71. A comparison between Panels A and B reveals that utility portfolios are relatively less risky than industrial portfolios after controlling for firm size. The comparison also reveals that, unlike industrial stocks, betas of the utility portfolios are not related to the market values of equity.

The negative correlation between firm size and beta in the industrial sample may introduce a multicolinearity problem in estimating equation (2). Banz (p.11) had addressed this issue and concluded that the test results are not sensitive to the multicolinearity problem. For the utility sample, this problem does not exist.

3. Tests on the Coefficients of Beta and Size

The beta and firm size are used to estimate γ_1 and γ_2 in equation (2). A t-statistic is used to test if the mean values of the gammas are significantly different from zero. The tests were performed for four 5-year periods which are reported in Table 3. The mean of the gammas and their t-statistic are presented in Panel A for the utilities and in Panel B for the industrial firms.

The empirical results for the utility sample are reported in Panel A of Table 3. When monthly returns are used, 60 regressions were run to obtain 60 pairs of gammas for each of the 5-year periods. When daily returns are used, over 1200 regressions were run for each period to obtain the gammas. The results are similar: in all of the time periods tested, none of the average coefficients for beta and size are significantly different from zero. When weekly returns are used, 260 pairs of gammas were obtained. The average coefficients for beta are not significant in any test period, and the average coefficients for size are not significant in three of the test periods. For the test period of 1978-82, the average coefficient for size is significantly negative at a 5% level.

The test results for the industrial sample are reported in Panel B of Table 3. When monthly returns are used, the average coefficient estimates for size and beta are significant and have the expected sign only in the 1983-87 test period. When weekly returns are used, only the size variable is significantly negative in the 1978-82 period. When daily returns are used, the coefficient estimates for betas and size are not significant at any conventional level.

According to the CAPM, beta is the sole determinant of stock returns. It is expected that the coefficient for beta is significantly positive. However, the empirical findings reported in this study and in Fama and French (1992) only provide weak support for beta in explaining stock returns. The empirical findings in this study also suggest that the size effect varies over time. It is not unusual to document the firm size effect at certain time periods but not at others. Banz (1981) found that the size effect is not stable over time with substantial differences in the magnitude of the coefficient of the size factor (p.9, Table 1). Brown, Kleidon and Marsh (1983) not only have shown that size effect is not constant over time but also have reported a reversal of the size anomaly for certain years.

The research design of this study allows us to keep the sample, test period, and methodology the same with the holding-period being the only variable. The size effect is documented for the industrial sample in one of the four test periods when monthly returns are used and in another when weekly returns are used. When daily returns are used, no size effect is observed. For the utility sample, the size effect is significant in only one test period when weekly returns are used. When monthly and daily returns are used, no size effect is found. Therefore, this study concludes that the size effect is not only time-period specific but also holding-period specific.

VI. Concluding Remarks

The fact that the two samples show different, though weak, results indicates that utility and industrial stocks do not share the same characteristics. First, given firm size, utility stocks are consistently less risky than industrial stocks. Second, industrial betas tend to decrease with firm size but utility betas do not. These findings may be attributed to the fact that all public utilities operate in an environment with regional monopolistic power and regulated financial structure. As a result, the business and financial risks are very similar among the utilities regardless of their sizes. Therefore, utility betas would not necessarily be expected to be related to firm size.

The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for the utility stocks. This implies that although the size phenomenon has been strongly documented for the industriales, the findings suggest that there is no need to adjust for the firm size in utility rate regulations.

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Table 1

Average Equity Size of the Utility Portfolios at the Beginning and End of the Test Period
(Dollar figures in millions)

	A: Beginning (1968)	B: End (1987)
MV_1	$31	$62
MV_2	$77	$177
MV_3	$113	$334
MV_4	$161	$475
MV_5	$220	$715
MV_6	$334	$957
MV_7	$437	$1,279
MV_8	$505	$1,805
MV_9	$791	$2,665
MV_{10}	$1,447	$5,399

Table 2

Betas of the Two Samples at the Beginning and End of the Test Period

	Monthly Betas		Weekly Betas		Daily Betas	
	1963-67	1982-86	1963-67	1982-86	1963-67	1982-86
Panel A: Industrial Firms						
MV_1	0.89	1.00	1.15	0.95	1.11	0.92
MV_2	0.94	0.87	1.07	1.01	1.14	1.01
MV_3	0.88	0.82	1.12	0.86	1.14	1.04
MV_4	0.69	0.74	1.00	0.83	1.03	0.86
MV_5	0.73	0.80	1.05	0.96	1.13	1.01
MV_6	0.66	0.82	1.03	1.01	1.05	1.04
MV_7	0.64	0.81	0.97	1.04	0.98	1.09
MV_8	0.62	0.75	0.97	1.11	1.00	1.20
MV_9	0.52	0.78	0.84	1.06	0.94	1.16
MV_{10}	0.43	0.65	0.78	1.01	0.86	1.22
Panel B: Public Utilities						
MV_1	0.30	0.37	0.31	0.43	0.30	0.40
MV_2	0.28	0.38	0.37	0.47	0.36	0.44
MV_3	0.22	0.42	0.33	0.42	0.31	0.49
MV_4	0.27	0.35	0.36	0.52	0.34	0.54
MV_5	0.25	0.45	0.37	0.61	0.35	0.62
MV_6	0.25	0.41	0.39	0.54	0.40	0.65
MV_7	0.20	0.35	0.34	0.54	0.37	0.63
MV_8	0.17	0.38	0.34	0.65	0.33	0.68
MV_9	0.19	0.34	0.35	0.60	0.34	0.71
MV_{10}	0.18	0.29	0.38	0.59	0.39	0.71

Table 3

Tests on the Mean Coefficients of Beta (γ_1) and Size (γ_2)

$$R_{pt} = \gamma_{ot} + \gamma_{1t}\hat{\beta}_{pt} + \gamma_{2t}\hat{S}_{pt} + U_{pt}$$

Returns Used:		Monthly (t-value)	Weekly (t-value)	Daily (t-value)
Panel A: Utility Sample				
1968-72	γ_1	-0.46% (-0.26)	-0.32% (-0.42)	-0.02% (-0.18)
	γ_2	-0.07% (-0.78)	-0.01% (-0.51)	-0.00% (-0.46)
1973-77	γ_1	-0.28% (-0.13)	0.14% (0.14)	-0.03% (-0.21)
	γ_2	-0.11% (-0.70)	-0.03% (-0.67)	-0.00% (-0.53)
1978-82	γ_1	0.55% (0.36)	0.54% (1.00)	0.05% (0.43)
	γ_2	-0.10% (-0.75)	-0.05% (-1.71)*	-0.01% (-1.60)
1983-87	γ_1	1.74% (1.28)	-0.24% (-0.51)	-0.02% (-0.18)
	γ_2	-0.16% (-1.54)	-0.03% (-0.86)	-0.01% (-0.63)
Panel B: Industrial Sample				
1968-72	γ_1	-0.36% (-0.27)	-0.28% (-0.55)	-0.02% (-0.32)
	γ_2	0.07% (0.43)	-0.01% (-0.19)	0.00% (0.51)
1973-77	γ_1	1.34% (0.64)	-0.23% (-0.31)	0.14% (1.45)
	γ_2	-0.01% (-0.06)	-0.04% (-0.85)	-0.00% (-0.64)
1978-82	γ_1	-0.84% (-0.28)	-0.56% (-0.91)	-0.09% (-0.81)
	γ_2	-0.29% (-0.75)	-0.01% (-1.72)*	-0.00% (-1.33)
1983-87	γ_1	2.51% (1.83)*	0.34% (0.64)	0.11% (1.40)
	γ_2	-0.25% (-1.90)*	-0.01% (-0.43)	0.00% (0.14)

* Significant at the 5% level based on a one-tailed test.

Corning Implied Credit Metrics

	Per Company	Ratings Category	Per Staff	Ratings Category
	RY22		**RY22**	
Net Income	$3,733,586		$2,773,938	
Depreciation and Amortization	$5,158,266		$2,808,017	
Deferred Income Taxes	$579,119		$579,119	
Funds From Operation (FFO)	$8,891,852		$5,581,955	
Cash Flow From Operation (CFO)	$9,470,971		$6,161,074	
Free Operating Cash Flow (FOCF)	$4,268,428		$958,531	
Discretionary Cash Flow (DCF)	$2,058,640		($1,251,257)	
Net Income	$3,733,586		$2,773,938	
Interest Expense	$1,515,310		$1,488,924	
Income Tax expense	$1,321,104		$981,478	
Depreciation and Amortization	$5,158,266		$2,808,017	
EBIT	$6,570,000		$5,244,341	
EBIT/Interest	4.34x		3.52x	
EBITDA	$11,728,266		$8,052,358	
EBITDA/Interest	7.74x		5.41x	
Capital Expenditures	$5,202,543		$5,202,543	
Dividend Payments	$2,209,788		$2,209,788	
Accumulated Deferred Income Taxes	$10,192,739		$10,192,739	
Total Average Debt	$34,252,919		$37,268,938	
Total Average Capitalization	$69,581,783		$69,016,552	
Standard & Poor's Credit Metrics				
Funds from Operation/Debt	25.96%	Intermediate	14.98%	Significant
Debt/EBITDA (x)	2.92x	Intermediate	4.63x	Aggressive
(FFO +Interest)/interest	6.87x	Intermediate	4.75x	Significant
EBITDA/Interest	7.74x	Intermediate	5.41x	Intermediate
CFO/Debt	27.65%	Modest	16.53%	Significant
FOCF/Debt	12.46%	Intermediate	2.57%	Aggressive
DCF/Debt	6.01%	Significant	-3.36%	Aggressive
Business Risk Profile		Excellent		Excellent
Implied Rating		A+/A		#N/A
Moody's Credit Metrics				
(CFO pre-WC + Interest)/Interest	7.25x	Aa2	5.14x	A2
CFO pre-WC / Debt	27.65%	Aa3	16.53%	Baa2
(CFO pre-WC-Dividends)/Debt	21.20%	A1	10.60%	Baa2
Debt/Capitalization	42.94%	A1	47.05%	A3
Implied Rating		A2		A3

Detailed Moody's Credit Metrics Analysis: Per Company

Qualitative Factors	Weight[1]	Rating[2]	Score	W'ted Score
Regulatory Framework	**25%**			
Legislative and Judicial Underpinnings of the Regulatory Frame work	12.5%	A	6	0.75
Consistency and Predictability of Regulation	12.5%	A	6	0.75
Ability to Recover Cost and Earn Returns	**25%**			
Timeliness of Recovery of Operating and Capital Costs	12.5%	Aa	3	0.38
Sufficiency of Rates and Returns	12.5%	Baa	9	1.13
Diversity	**10%**	Baa	9	0.90
Financial Strength	**40%**			
Cash Flow Interest Coverage	7.5%	Aa2	3	0.23
Cash Flow/Debt	15.0%	Aa3	4	0.60
Retained Cash Flow/Debt	10.0%	A1	5	0.50
Debt/Capital	7.5%	A1	5	0.38
Total	**100%**		4.25	**5.60**
Implied Rating				**A2**

Detailed Moody's Credit Metrics Analysis: Per Staff

Qualitative Factors	Weight	Rating	Score	W'ted Score
Regulatory Framework	**25%**			
Legislative and Judicial Underpinnings of the Regulatory Frame work	12.5%	A	6	0.75
Consistency and Predictability of Regulation	12.5%	A	6	0.75
Ability to Recover Cost and Earn Returns	**25%**			
Timeliness of Recovery of Operating and Capital Costs	12.5%	Aa	3	0.38
Sufficiency of Rates and Returns	12.5%	Baa	9	1.13
Diversity	**10%**	Baa	9	0.90
Financial Strength	**40%**			
Cash Flow Interest Coverage	7.5%	A2	6	0.45
Cash Flow/Debt	15.0%	Baa2	9	1.35
Retained Cash Flow/Debt	10.0%	Baa2	9	0.90
Debt/Capital	7.5%	A3	7	0.53
Total	**100%**			**7.13**
				A3

CORNING NATURAL GAS CORPORATION
Fixed Interest True-Up Deferred Debit
Forecast - Rate Year Ended January 31, 2022

Eligible Amount of Deferable Interest

	June	July	August	September	October	November	December	January	February	March	April	May	Total
Rate Year 1 (5/31/2018)	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,906.98	$ 15,906.98	$ 15,906.98	$ 15,906.98	$ 15,906.98	$ 15,906.98	95,441.87
Rate Year 2 (5/31/2019)	$ 15,906.98	$ 15,906.98	$ 15,906.98	$ 15,906.98	$ 15,906.98	$ 15,906.98	$ 17,191.16	$ 17,189.79	$ 17,188.38	$ 17,186.94	$ 17,185.46	$ 17,183.94	198,567.54
Rate Year 3 (5/31/2020)	$ 17,182.39	$ 17,180.79	$ 17,179.16	$ 17,177.48	$ 17,175.76	$ 15,931.44	$ 15,991.18	$ 15,986.49	$ 15,981.69	$ 15,976.77	$ 15,971.73	$ 14,201.90	195,936.77
Stub Period (1/31/2021)	$ 14,179.48	$ 14,156.57	$ 14,133.15	$ 14,109.20	$ 14,084.70	$ 14,059.63	$ 11,535.76	$ 11,598.57					107,857.06
													597,803.24

Authorized Interest Rate * Eligible Amount of Debt

	June	July	August	September	October	November	December	January	February	March	April	May	Total
Rate Year 1 (5/31/2018)	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	681,727.63
Rate Year 2 (5/31/2019)	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	681,727.63
Rate Year 3 (5/31/2020)	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	681,727.63
Stub Period (1/31/2021)	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64					454,485.09
													2,499,667.97

Actual Embedded Long Term Interest Rate * Eligible Amount of Debt

	June	July	August	September	October	November	December	January	February	March	April	May	Total
Rate Year 1 (5/31/2018)	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 56,810.64	$ 72,717.61	$ 72,717.61	$ 72,717.61	$ 72,717.61	$ 72,717.61	$ 72,717.61	777,169.50
Rate Year 2 (5/31/2019)	$ 72,717.61	$ 72,717.61	$ 72,717.61	$ 72,717.61	$ 72,717.61	$ 72,717.61	$ 74,001.80	$ 74,000.42	$ 73,999.02	$ 73,997.57	$ 73,996.09	$ 73,994.58	880,295.17
Rate Year 3 (5/31/2020)	$ 73,993.02	$ 73,991.43	$ 73,989.79	$ 73,988.12	$ 73,986.40	$ 72,742.08	$ 72,801.81	$ 72,797.13	$ 72,792.32	$ 72,787.41	$ 72,782.37	$ 71,012.53	877,664.40
Stub Period (1/31/2021)	$ 70,990.12	$ 70,967.21	$ 70,943.79	$ 70,919.83	$ 70,895.34	$ 70,870.27	$ 68,346.39	$ 68,409.20					562,342.15
													3,097,471.22

Actual Embedded Long Term Interest Rate

	June	July	August	September	October	November	December	January	February	March	April	May	Average
Rate Year 1 (5/31/2018)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	4.16%	4.16%	4.16%	4.16%	4.16%	4.16%	3.71%
Rate Year 2 (5/31/2019)	4.16%	4.16%	4.16%	4.16%	4.16%	4.16%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.20%
Rate Year 3 (5/31/2020)	4.23%	4.23%	4.23%	4.23%	4.23%	4.16%	4.16%	4.16%	4.16%	4.16%	4.16%	4.06%	4.18%
Stub Period (1/31/2021)	4.06%	4.06%	4.06%	4.06%	4.06%	4.05%	3.91%	3.91%					4.02%
													4.03%

Calculation of Debt Financed Portion of Rate Base

	Average Rate Base	Debt-Fin. Portion
Rate Year 1 (5/31/2018)	$ 57,630,832.00	$ 29,426,302.82
Rate Year 2 (5/31/2019)	$ 61,083,022.00	$ 31,188,991.03
Rate Year 3 (5/31/2020)	$ 64,112,131.00	$ 32,735,654.09
Stub Period (1/31/2021)	$ 64,112,131.00	$ 32,735,654.09

Basic Parameters

Debt Ratio	51.06%
Auth. Int. Rate	3.25%
Debt Per Last JP	27,968,313.00
75% of JP Debt	20,976,234.75

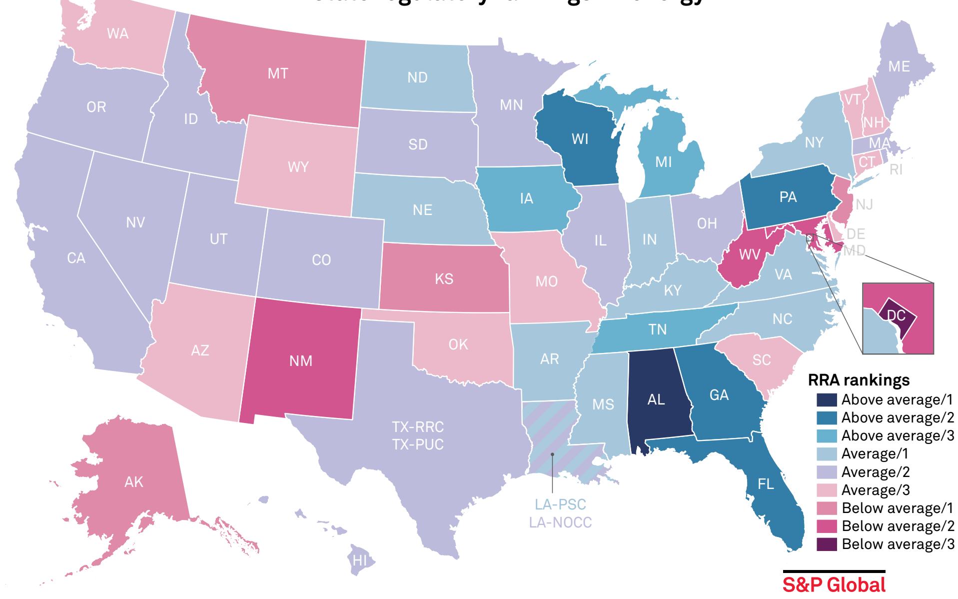
S&P Global
Market Intelligence

May 19, 2020
spglobal.com/marketintelligence

RRA Regulatory Focus
State Regulatory Evaluations
Assessments of regulatory climates for energy utilities

Regulatory Research Associates, a group within S&P Global Market Intelligence, evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia, a total of 53 jurisdictions, on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's energy utilities.

RRA state regulatory rankings — energy



As of May 19, 2020.
RRC = Railroad Commission; PUC = Public Utility Commission; PSC = Public Service Commission; NOCC = New Orleans City Council
Map credit: Ciaralou Agpalo Palicpic
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Each evaluation is based upon consideration of the numerous factors affecting the regulatory process including gubernatorial involvement, legislation and court activity and may be adjusted as events occur that cause RRA to modify its view of the regulatory risk for a given jurisdiction.

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RRA State Regulatory Evaluations *
Energy

Above Average 1	Average 1	Below Average 1
Alabama	Arkansas	Alaska
	Indiana	Kansas
	Kentucky	Montana
	Louisiana — PSC	New Jersey
	Mississippi	
	Nebraska	
	New York	
	North Carolina	
	North Dakota	
	Virginia	
Above Average 2	**Average 2**	**Below Average 2**
Georgia	California	Maryland
Florida	Colorado	New Mexico
Pennsylvania	Hawaii	West Virginia
Wisconsin	Idaho	
	Illinois	
	Louisiana—NOCC	
	Massachusetts	
	Minnesota	
	Nevada	
	Ohio	
	Oregon	
	Rhode Island	
	South Dakota	
	Texas—PUC	
	Texas—RRC	
	Utah	
Above Average 3	**Average 3**	**Below Average 3**
Iowa	Arizona	Dist, of Columbia
Michigan	Connecticut	
Tennessee	Delaware	
	Maine	
	Missouri	
	New Hampshire	
	Oklahoma	
	South Carolina	
	Vermont	
	Washington	
	Wyoming	

As of May 19, 2020.
NOCC = New Orleans City Counsil; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
*Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA also reviews evaluations as key rate case and other regulatory decisions are issued, when updating Commission Profiles and when publishing this quarterly comparative report. The issues considered are discussed in RRA Research Notes, Commission Profiles, Rate Case Final Reports and Topical Special Reports. RRA also considers information obtained from contacts with commission, company and government personnel in the course of its research. The final evaluation is an assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative and court actions.

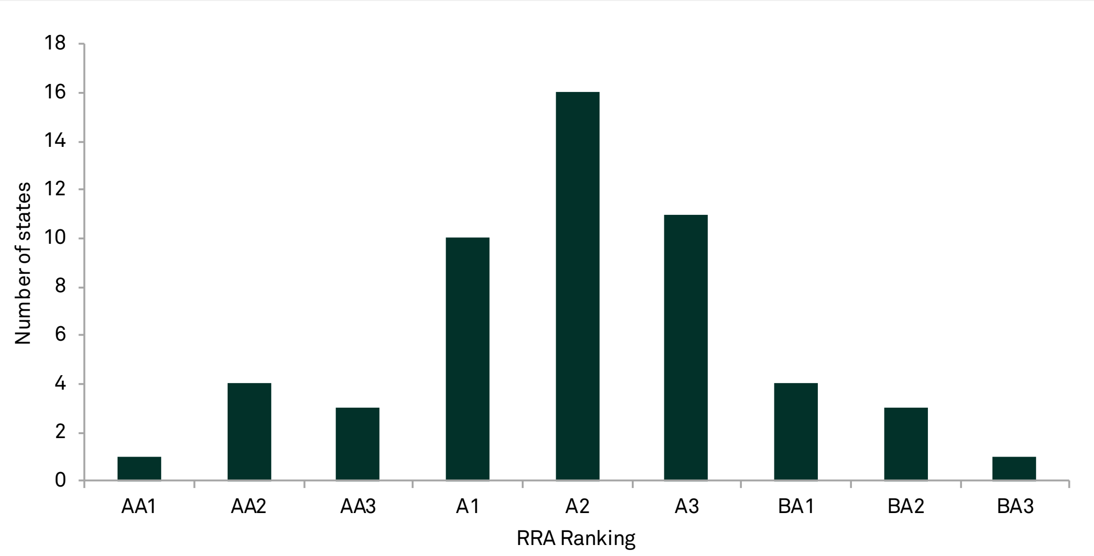
An Above Average designation indicates that, in RRA's view, the regulatory climate in the jurisdiction is relatively more constructive than average, representing lower risk for investors that hold or are considering acquiring the securities issued by the utilities operating in that jurisdiction.

At the opposite end of the spectrum, a Below Average ranking would indicate a less constructive, or higher-risk, regulatory climate from an investor viewpoint.

A rating in the Average category would imply a relatively balanced approach on the part of the governor, the legislature, the courts and the commission when it comes to adopting policies that impact investor and consumer interests.

Within the three principal rating categories, the designations 1, 2 and 3 indicate relative position, with a 1 implying a more constructive relative ranking within the category, a 2 indicating a midrange ranking within the category and a 3 indicating a less constructive ranking within the category.

State regulatory rankings distribution*



As of May 19, 2020.
* Graph is based on rankings of regulatory climate for energy utilities only.
AA = Above Average; A = Average; BA = Below Average
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA attempts to maintain a "normal distribution" of the rankings, with the majority of the states classified in one of the three Average categories. The remaining states are then split relatively evenly between the Above Average and Below Average classifications, as seen in the accompanying chart that depicts the current ranking distribution.

For a more in-depth discussion of the factors RRA reviews as part of its ratings process, see the Overview of RRA rankings process section that begins on page 8.

Rankings changes

Since the publication of the previous “State Regulatory Evaluations” report, which was released on March 25, 2020, RRA has made no rankings changes.

However, in conjunction with the release of the March review RRA made six rankings changes.

RRA raised the ranking of Connecticut regulation to Average/3 from Below Average/1. The ranking shift reflects modestly constructive ratemaking actions the Connecticut Public Utilities Regulatory Authority, or PURA, has taken in recent years, including a focus on grid modernization.

RRA also raised the ranking of Iowa regulation to Above Average/3 from Average/1, as constructive measures stemming from the state’s omnibus energy legislation enacted in 2018 have materialized in recent months.

In addition, RRA raised the ranking of Louisiana regulation to Average/1 from Average/2, recognizing the impact of the state’s use of alternative regulation plans many of which contain earnings-sharing provisions and include other constructive provisions that address various utility costs and investments in a timely manner.

On the other hand, RRA lowered the ranking of Maine regulation to Average/3 from Average/2 due to recent restrictive developments related to mergers and rate case activity.

RRA also lowered the ranking of Utah regulation to Average/2 from Average/1. This was driven primarily by a recent restrictive Public Service Commission of Utah decision for Dominion Energy Inc. subsidiary Questar Gas Co., and in light of constructive developments in certain other jurisdictions that caused a shift in Utah’s relative position within the RRA rankings framework.

RRA state regulatory evaluations

State-by-state listing — energy

State	Ranking	State	Ranking	State	Ranking
Alabama	Above Average/1	Louisiana—NOCC	Average/2	Ohio	Average/2
Alaska	Below Average/1	Louisiana—PSC	Average/1	Oklahoma	Average/3
Arizona	Average/3	Maine	Average/3	Oregon	Average/2
Arkansas	Average/1	Maryland	Below Average/2	Pennsylvania	Above Average/2
California	Average/2	Massachusetts	Average/2	Rhode Island	Average/2
Colorado	Average/2	Michigan	Above Average/3	South Carolina	Average/3
Connecticut	Average/3	Minnesota	Average/2	South Dakota	Average/2
Delaware	Average/3	Mississippi	Average/1	Tennessee	Above Average/3
District of Columbia	Below Average/2	Missouri	Average/3	Texas—PUC	Average/2
Florida	Above Average/2	Montana	Below Average/1	Texas—RRC	Average/2
Georgia	Above Average/2	Nebraska	Average/1	Utah	Average/2
Hawaii	Average/2	Nevada	Average/2	Vermont	Average/3
Idaho	Average/2	New Hampshire	Average/3	Virginia	Average/1
Illinois	Average/2	New Jersey	Below Average/1	Washington	Average/3
Indiana	Average/1	New Mexico	Below Average/2	West Virginia	Below Average/2
Iowa	Abive Average/3	New York	Average/1	Wisconsin	Above Average/2
Kansas	Below Average/1	North Carolina	Average/1	Wyoming	Average/3
Kentucky	Average/1	North Dakota	Average/1		

As of May 19, 2020.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission;
RRC = Railroad Commission
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Finally, RRA lowered the ranking of Virginia regulation to Average/1 from Above Average/3. This was the second ranking reduction RRA made for Virginia in the prior 12 months. While RRA perceives an increase in the level of regulatory risk for the utilities operating in the state, the Virginia regulatory climate still remains somewhat more constructive than average from an investor viewpoint.

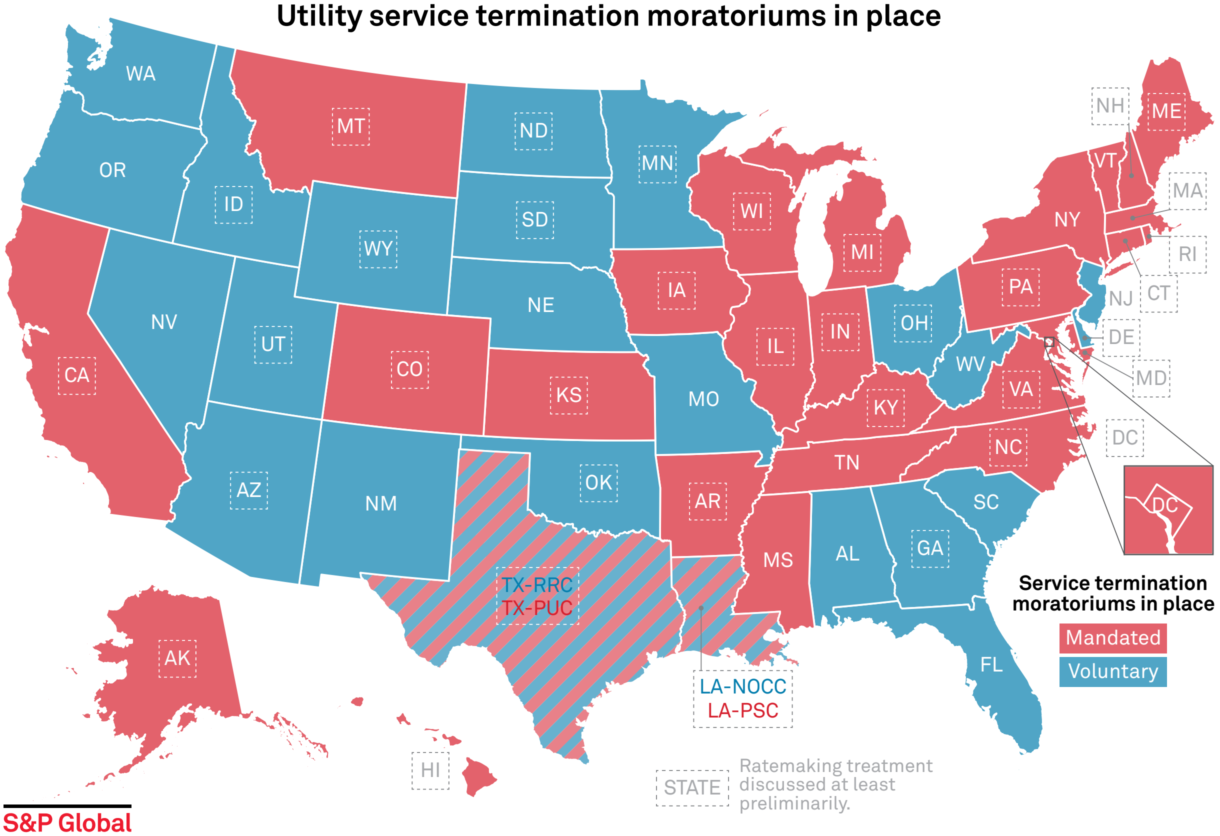
Issues to watch

Coronavirus/COVID 19

The coronavirus outbreak presents challenges for U.S. utilities on several fronts, including but not limited to, expected reductions in usage as businesses, schools and government buildings remain shuttered, lower revenues due to a higher anticipated occurrence of bad-debt/uncollectibles and increased operating costs associated with enhanced biohazard safety measures and maintaining sufficient staffing to ensure safety and reliability of utility service.

These challenges have the potential to significantly impact the financial performance of the investor-owned utilities, increasing the overall level of investor risk. Mechanisms are in place in several states that, all else being equal, could blunt the impact or allow the impacts to be addressed on a more expedited basis, and these mechanisms are already baked into RRA's rankings of those states.

Utility service termination moratoriums in place



S&P Global
Market Intelligence

Data gathered as of May 11, 2020.
RRC = Railroad Commission; PUC = Public Utility Commission; NOCC = New Orleans City Council; PSC = Public Service Commission
Map credit: Ciaralou Agpalo Palicpic
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

While maintaining essential utility circumstances in these difficult times has been the primary focus for policymakers, as the crisis has dragged on, regulators have begun to consider methodologies to address COVID-19 related costs. As of May 11, regulators in 17 jurisdictions had authorized the utilities to track and defer COVID-19 related costs. Since then two other states, Virginia and Pennsylvania have approved deferrals on a limited basis. In 13 other states, proceedings are pending to discuss a workable framework to address COVID-19 costs and five states have indicated that the service suspension do not relieve customers of the obligation to pay for the service they have used.

RRA has posited that securitization may ultimately be a viable option for recovery of the deferred balances.

COVID-19 cost recovery provisions

Deferral		Customer payment plan	Pending	
Alaska	Maryland	Colorado	Arizona	Missouri
Arkansas	Michigan	New Hampshire	Delaware	Montana
California	Minnesota	North Carolina	Indiana	North Dakota
Connecticut	Oklahoma	Ohio	Kansas	South Dakota
Dist. of Columbia	Pennsylvania	Rhode Island	Kentucky	Utah
Georgia[1]	Texas-PUC[2]		Maine	Wisconsin
Hawaii	Texas-RRC		Masschusetts	
Idaho	Virginia			
Illinois	Wyoming			
Iowa				

As of May 11, 2020.
PUC=Public Utility (ies) Commission; RRC=Railroad Commission
Deferral=Costs and/or lost revenues may be deferred for future recovery.
Customer payment plan=Lost revenue associated with suspension moratorium to be recovered on a customer-specific basis over time.
Pending=Proceeding under way/legislation pending to determine cost recovery
[1] Deferral approved for one utiity for another the lost revenue associated with suspension moratorium would be recovered through existing rate plan.
[2]Costs and/or lost revenues may be deferred for future recovery for utilities; interim funding mechanism in place for retail electric providers.
Source: Regulatory Research Associates, a group withinn S&P Global Market Intelligence.

RRA has also observed that fewer companies are filing rate cases and the schedules in others have been delayed. Similarly, concerns regarding the spread of the virus and the need to address the broader economic impacts have disrupted legislative sessions across the U.S., slowing the process and creating additional uncertainty for the sector as a whole and in some states primaries and/or elections have also been delayed/postponed.

Elections

In addition to the U.S. Presidential election, the 2020 general elections will feature 19 utility commissioner and 11 gubernatorial elections. Changes in regulatory personnel that result from these elections could lead to policy shifts in the affected jurisdictions.

A total of four commissioners in three states where regulators are elected, are ineligible to run for reelection in November due to term limits — Arizona, Montana, where there are two, and New Mexico. Notably one Arizona commissioner who was seeking re-election has been removed from the ballot after issues with the authenticity of the signatures required to appear on the ballot were raised.

In Texas, Commissioner Ryan Sitton failed to win the Republican primary to retain his seat on the Railroad Commission of Texas. The winner, James Wright, will face the victor in a Democratic primary run off that is scheduled for July 20 between Chrysta Castaneda and Roberto Alonzo.

The chief executive of the jurisdiction appoints the utility commission members in nine of the 11 states where gubernatorial elections will be held. Nineteen commissioner terms in eight of those states will expire during the governor-elects' new terms and eight terms will expire within the first 12 months following the election.

States to watch

In addition to the changes discussed above, there are several states where ongoing issues bear close scrutiny.

In Arizona, a proceeding is ongoing in which the commission is considering an overhaul of the regulatory framework including the implementation of retail competition for generation and adoption of a 100% renewable portfolio standard, or RPS. While RRA does not take a view on whether the introduction of retail competition or the RPS is in and of itself positive or negative, experience shows that the transition process can be fraught with risk, and so developments in this proceeding bear watching.

In addition, a commission-mandated rate case is underway for Pinnacle West Capital Corp. subsidiary Arizona Public Service Co., while proceedings are also pending for Southwest Gas Corp. and Fortis Inc. subsidiary Tucson Electric Power Co.

In California, the team is continuing to monitor developments with respect to the bankruptcy proceedings involving Pacific Gas & Electric and its parent PG&E Corp., including the prospects for a state takeover or break up of the company. Meanwhile, issues with respect to the treatment of wildfire costs continue to await a final resolution.

Other jurisdictions that bear watching include the District of Columbia, where Exelon Corp. subsidiary Potomac Electric Power, or Pepco, filed its first ever multiyear rate plan. Intervenors to the case have called for the commission to reject the proposal and instead issue a decision based on a traditional test year filing. A final order is expected in late-2020.

RRA continues to monitor the ongoing proceedings in Georgia with respect to Southern Company subsidiary Georgia Power Co.'s Vogtle nuclear plant expansion project. The company filed its 22nd periodic monitoring report on the construction earlier this year, but as the commission's review has proceeded, the company has announced that it has reduced its workforce at the facility by 20% due to the COVID-19 outbreak.

In Maryland, RRA is monitoring the Maryland Public Service Commission's progress as it implements its new policy allowing the use of multiyear rate plans to mitigate regulatory lag. Energy storage pilot program proceedings are also ongoing, as is the commission' review of the proposed acquisition of Elkton Gas by Chesapeake Utilities Corp. Elkton Gas is currently owned by South Jersey Industries.

Montana also bears watching, as recent rate case decisions have produced authorized returns on equity that have trended toward nationwide averages; however, it is too soon to say whether this heralds the beginning of a sustained improvement in the regulatory climate. It is also noteworthy that three of the five commissioner seats will be up for election during the 2020 general election.

RRA continues to monitor the situation in New York with respect to the heightened politicization of certain energy regulatory matters in the state. During the summer of 2019, a political backlash ensued surrounding power outages in Consolidated Edison Inc. subsidiary Consolidated Edison Co. of New York's, or CECONY's, service area. Both Gov. Andrew Cuomo and local politicians ratcheted up the criticism of CECONY's reliability. The utility reached a deal, which New York Public Service Commission adopted in January 2020, specifying a well-below-industry-average 8.8% ROE as part of a three-year electric and gas rate plan.

Political fallout surrounding the utilities' self-imposed moratorium on new natural gas service is apparently creating some overhang for National Grid USA subsidiaries Brooklyn Union Gas Co. and KeySpan Gas East Corp Even though a settlement was reached in November 2019 that lifted the moratorium and called for the utilities to pay $36 million to compensate customers hurt by the moratorium. In testimony filed in April 2020, the PSC staff recommended an 8.2% ROE for both companies, substantially below those adopted in the CECONY cases. Rate cases are also pending for Iberdrola's four New York utility operating companies, and the staff has also proposed an 8.2% ROE for these companies. A settlement in those cases is expected to be filed in the near future.

Two recently completed rates cases before the Public Utility Commission of Texas, one for CenterPoint Energy Inc. subsidiary CenterPoint Energy Houston Electric LLC and the other for American Electric Power Co. Inc. subsidiary AEP Texas Inc., were particularly contentious, even though settlements were reached, due to the commission's request for testimony on and ultimate adoption of enhanced ring-fencing requirements. A proceeding is pending for Xcel subsidiary Southwestern Public Service where similar issues are being considered.

Recent State Regulatory Reviews

In recent months, RRA has issued State Regulatory Reviews affirming the rankings of several jurisdictions.

In a review released on April 29, 2020, RRA maintained the Above Average/3 ranking of Michigan regulation, finding that Michigan regulatory climate is generally constructive from an investor perspective and continues to support significant capital investments and timely recovery of these costs.

In a review of Idaho published on April 20, 2020, RRA noted that the regulatory climate remains relatively balanced from an investor viewpoint and maintained the Average/2 ranking of that jurisdiction.

In a review issued on March 10, 2020, RRA affirmed the Average/1 ranking of the North Carolina regulatory climate. In RRA's view, North Carolina is also generally balanced from an investor viewpoint, but is a bit more constructive than average.

In a review released on Jan. 6, 2020, RRA affirmed its Average/3 ranking of South Carolina regulation indicating that while generally balanced, the environment in the state is somewhat more restrictive than average from an investor viewpoint.

For a complete listing of RRA's in-depth reports, see the Energy Research Library.

RRA state regulatory evaluations — energy*

Above average/1	Above average/2	Above average/3	Average/1	Average/2	Average/3	Below average/1	Below average/2	Below average/3
Alabama	Florida	Iowa	Arkansas	California	Arizona	Alaska	Maryland	Dist. of Columbia
	Georgia	Michigan	Indiana	Colorado	Connecticut	Kansas	New Mexico	
	Pennsylvania	Tennessee	Kentucky	Hawaii	Delaware	Montana	West Virginia	
	Wisconsin		Louisiana — PSC	Idaho	Maine	New Jersey		
			Mississippi	Illinois	Missouri			
			Nebraska	Louisiana — NOCC	New Hampshire			
			New York	Massachusetts	Oklahoma			
			North Carolina	Minnesota	South Carolina			
			North Dakota	Nevada	Vermont			
			Virginia	Ohio	Washington			
				Oregon	Wyoming			
				Rhode Island				
				South Dakota				
				Texas—PUC				
				Texas—RRC				
				Utah				

As of May 19, 2020.
NOCC = New Orleans City Council; PUC = Public Utility Commission; RRC = Railroad Commission
*Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Please note that the State Regulatory Reviews are static versions of RRA's Commission Profiles, which are updated on an ongoing basis.

Overview of RRA rankings process

RRA maintains three principal rating categories, Above Average, Average and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint and Below Average indicating a less constructive, higher-risk regulatory climate. Within each principal rating categories, the numbers 1, 2 and 3 indicate relative position. The designation 1 indicates a stronger or more constructive rating from an investor viewpoint; 2, a midrange rating; and 3, a less constructive rating. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

Methodology

While numerical scores employed, the rankings are subjective and are intended to be comparative in nature. RRA endeavors to maintain an approximate normal distribution with an approximately equal number of rankings above and below the average.

The rankings are designed to reflect the interest of both equity and fixed-income investors across more than 30 individual metrics. The individual scores are assigned based on the covering analysts' subjective judgement. The scores are then aggregated to create a single score for each state, with certain categories weighted more heavily than others.

The states are then ranked from lowest to highest and distributed among the nine categories to create an approximate normal distribution. This distribution is then reviewed by the team as a whole, and individual state rankings may be adjusted based on the covering analysts' recommendations, subject to review by a designated panel of senior analysts.

The variables that RRA considers in determining each state's ranking are largely the broad issues addressed in our State Regulatory Reviews/Commission Profiles and those that arise in the context of rate cases and are discussed in RRA Rate Case Final Reports.

The rankings not only reflect the decisions rendered by the state regulatory commission, but also take into account the impact of the actions taken by the governor, the legislature, the courts and the consumer advocacy groups. The policies examined pertain largely to rate cases and the ratemaking process, but issues such as industry restructuring, corporate governance, treatment of proposed mergers and the ongoing energy transition are also considered.

Please note: In the charts within this report that show the rankings by category, the jurisdictions in each category are listed in alphabetical order rather than by relative position within the category.

The summaries below provide an overview of the variables RRA looks at, including a brief discussion of how each can impact the ranking of a given regulatory environment.

Governor/Mayor

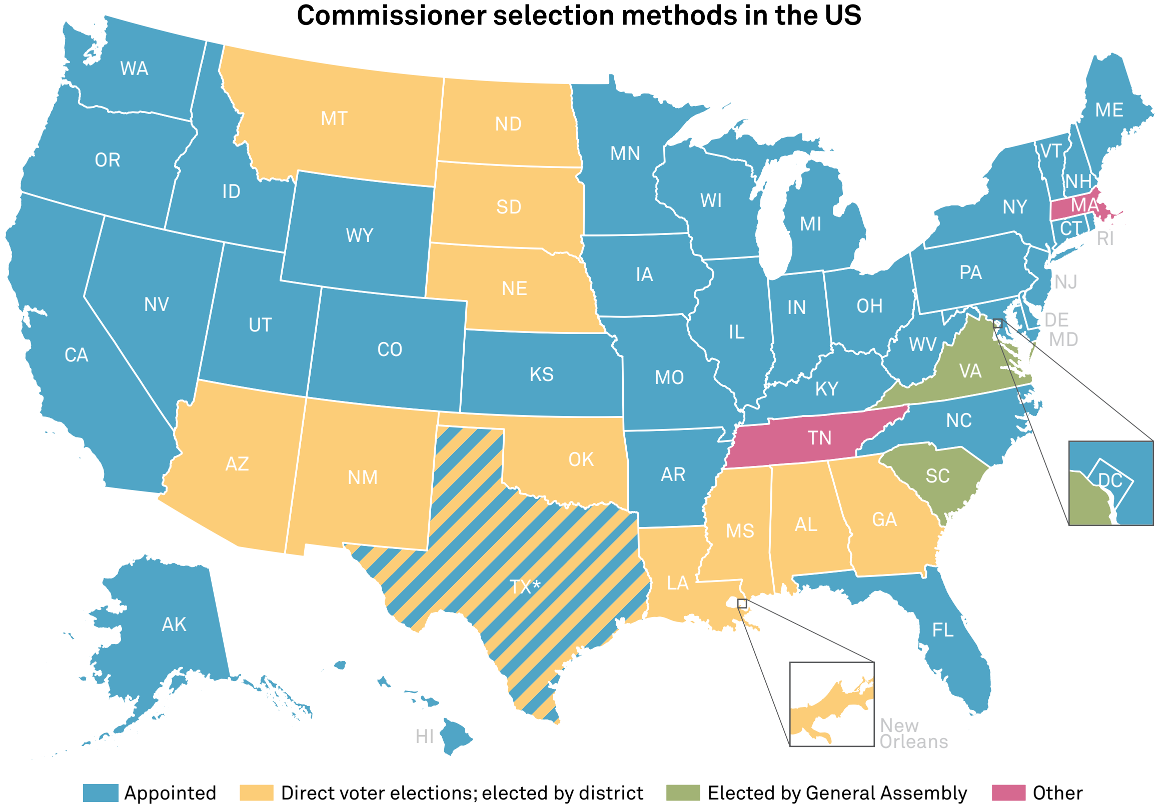
The impact the governor, or in the District of Columbia the mayor, may have depends largely on the individual; the issue of elected versus appointed commissioners is evaluated separately.

RRA takes no view on whether Republican governors or Democratic governors are more or less constructive. However, attributes of the governor or the gubernatorial election process that can move the needle here are: whether energy issues were a topic of debate in recent elections and what the tone/topic of the debate was, whether the governor seeks to involve himself or herself in the regulatory process, and what type of influence the governor is seeking to exert.

Commissioner selection process/membership

RRA looks at how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states in which commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election.

Commissioner selection methods in the US



Data as of May 19, 2020.
* The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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Realistically, a commissioner candidate who indicates support for the utilities and their shareholders, or appears to be amenable to rate increases is not likely to be popular with the voting public. In addition, there might not be specific experience requirements to run for commissioner; so, a newly elected candidate may have a steeper learning curve with respect to utility regulatory and financial issues, which could make discerning what decisions that individual might make more difficult and could increase uncertainty.

However, there have been some notable instances in which energy issues played a key role in gubernatorial/senatorial elections in states where commissioners are appointed, with detrimental consequences for the utilities, e.g., Illinois, Florida and Maryland, all of which were downgraded by RRA at the time in order to reflect the increase risk associated with increased political scrutiny of the regulatory process and policies within the jurisdiction.

In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator. In some instances, new commissioners have very little experience or exposure to utility issues, and in some respects, these individuals represent the highest level of risk, simply because there is no way to foresee what they will do or how long it will take them to "get up to speed." Controversy or "scandal" surrounding an individual and/or the potential for a conflict of interest are also red flags.

Similarly, a high rate of turn-over or the tendency to allow vacancies to stand unfilled for a long period of time add to the level of regulatory risk in RRA's view.

For additional information concerning the selection process in each state and the make-up of the commissions, refer to the RRA Regulatory Focus Topical Special Report entitled The Commissions .

Commission staff/consumer interest

Most commissions have a staff that participates in rate proceedings. In some jurisdictions the staff has a responsibility to represent the consumer interest, and in others the staff's statutory role is less defined. In addition, there may or may not be: additional state-level organizations that are charged with representing the interests of a certain class or classes of customers, such as the Attorney General or the Consumer Advocate; private consortia or lobbying groups that represent certain customer groups; and/or large-volume commercial and industrial customers that intervene directly in rate cases.

Generally speaking, the greater the number of consumer intervenors, the greater the level of uncertainty for investors. The level of risk for investors also depends on the caliber and influence of the intervening parties and the level of contentiousness in the rate case process. Even though a commission may not adopt an extreme position taken by an intervenor, the inclusion of an extreme position in the record for the case widens the range of possible outcomes, reducing certainty and increasing the risk of a negative outcome for investors. RRA's opinion on these issues is largely based on past experience and observations.

Settlements

In most instances, the ability of the parties to reach agreement without having to go through a fully litigated proceeding is considered constructive, particularly since it reduces the likelihood of court review after the fact. However, RRA also endeavors to ascertain whether the settlements arise because of a truly collaborative approach among the parties, or if they result from concern by the companies that the commissioners' views may be more extreme than the intervenors', or that the intervenors will take a much more extreme position in a litigated framework than in a closed-door settlement negotiation resulting in a less constructive outcome.

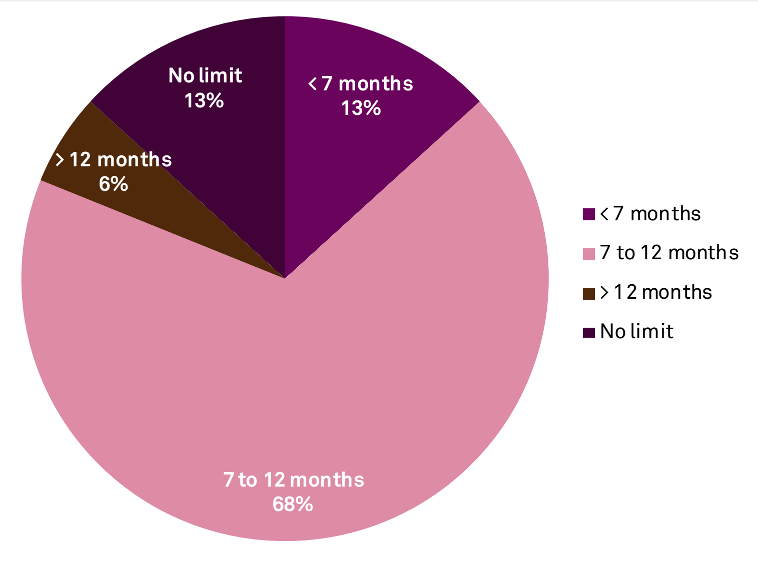
Rate case timing

For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame and the degree to which the commission adheres to that time frame.

Generally speaking, RRA views a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected.

About two-thirds of state commissions nationwide have a rule or statute that requires a rate case to be decided within seven to 12 months of filing.

Rate case time frame



Data gathered as of May 19, 2020.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Shorter time frames may apply for limited-issue proceedings, but there are very few states where a rate case will take less than seven months to be decided.

In addition, a shorter time frame for a decision generally reduces the likelihood that the actual conditions during the first year the new rates will be in effect will vary markedly from the test period utilized to set new rates, thus keeping regulatory lag to a minimum.

Interim procedures

The ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision in a rate case is viewed as constructive. However, should the commission approve a rate change that is markedly below the rates implemented on an interim basis, the utility would be required to refund any related over-collections, generally with interest.

In some instances, commission approval is required prior to the implementation of an interim increase and may or may not be easy to obtain, while in others, state law or commission rules permit the companies to implement interim rate increases as a matter of course. In some instances, the commission may establish a date prior to the final decision in the case that will be the effective date of the new rates. In these instances, the company may be permitted to recoup any revenue that was not collected between the effective date and the decision date.

Rate base

A commission's policies regarding rate base can also impact the ability of a utility to earn its authorized ROE. These policies are often outlined in state statutes, and the commission usually does not have much latitude with respect to these overall policies.

With regard to rate base, commissions are about evenly split between those that employ a year-end, or terminal valuation and those that utilize an average valuation, with one using a "date certain." In some instances, the commission may employ a different rate base valuation method depending on the utility type or the type of case — general rate case or limited-issue proceeding — or based on the test year selected by the company.

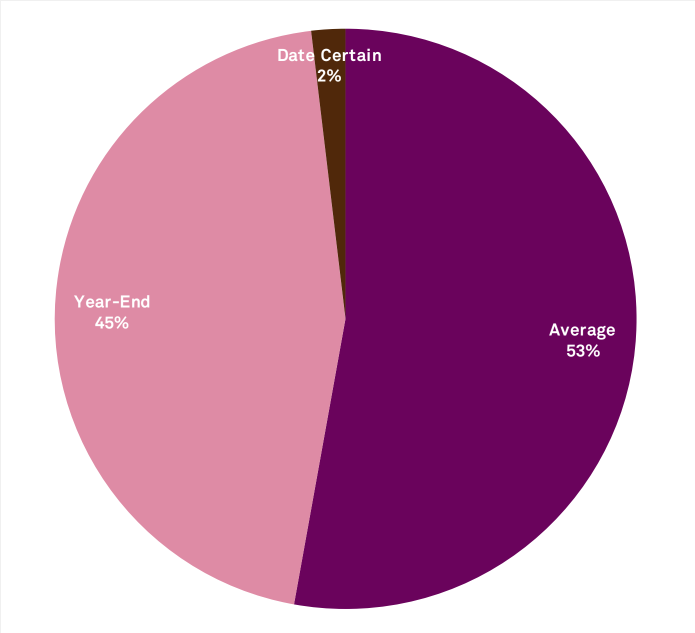
In general, assuming rate bases are rising, i.e., new investment is outpacing depreciation, a year-end valuation is preferable from an investor viewpoint.

Again, this relates to how well the parameters used to set rates reflect actual conditions that will exist during the rate-effective period; hence, the more recent the valuation, the more likely it is to approximate the actual level of rate base being employed to serve customers once the new rates are placed into effect.

Some commissions permit post-test year adjustments to rate base for "known and measurable" items, and, in general, this practice is beneficial to the utilities.

However, the rules with respect to what constitutes a known and measurable adjustment are not always specific, and there can be a good deal of controversy about what does and does not pass muster.

Rate Base Valuation Method



Data gathered as of May 19, 2020.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Another key consideration is whether state law and/or the commission generally permit the inclusion in rate base of construction work in progress, or CWIP, for a cash return. CWIP represents assets that are not yet, but ultimately will be, operational in serving customers.

Generally, investors view inclusion of CWIP in rate base for a cash return as constructive, since it helps to maintain cash flow metrics during a large construction cycle. Alternatively, the utilities accrue allowance for funds used during construction, which is essentially booking a return on the construction investment as a regulatory asset that is recoverable from ratepayers once the project in question becomes operational.

While this method bolsters earnings, it does not augment cash flow and does not support credit metrics. For a more in-depth look at rate base issues, refer to the RRA report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

Test period

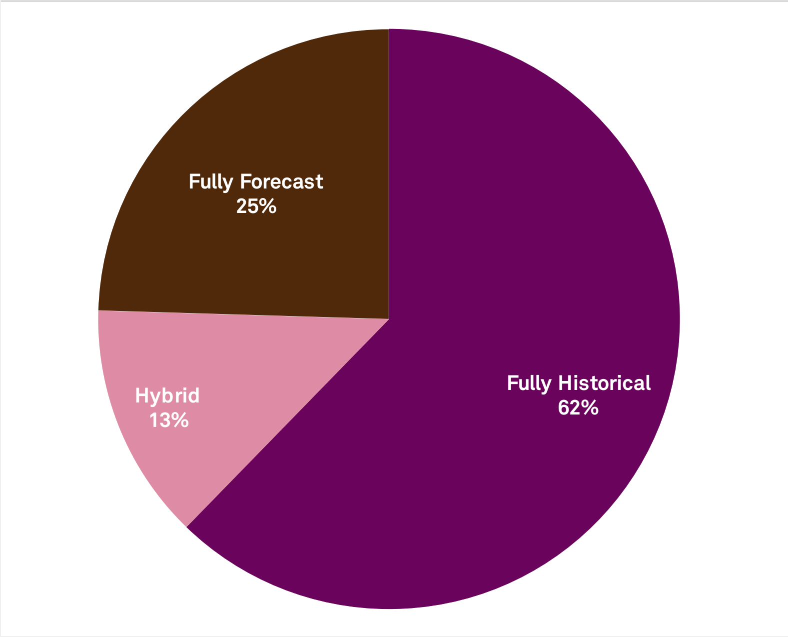
With regard to test periods, there are a number of different practices employed, with the extremes being fully forecast at the time of filing, which is considered to be most constructive, on the one hand, and fully historical at the time of filing, considered to be least constructive, on the other.

Some states utilize a combination of the two, in which a utility is permitted to file a rate case that is based on data that is fully or partially forecast at the time of filing and is later updated to reflect actual data that becomes known during the course of the proceeding.

In these cases, the test year is historical by the time a decision is ultimately rendered, and so regulatory lag remains something of a problem.

Almost two-thirds of the 53 jurisdictions covered by RRA utilize a test year that is historical at the time of filing. As with rate base valuation, in some states, commissions use different test period types for different types of proceedings or for different utility types. The accompanying map shows the predominant treatment in each state.

Rate case test year



Data gathered as of May 19, 2020.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Many of the jurisdictions allow for known and measurable adjustments to the test year, but the statutes governing the definition of known and measurable can be ambiguous, and there can be wide disagreement among the rate case parties as to which adjustments qualify.

Return on equity

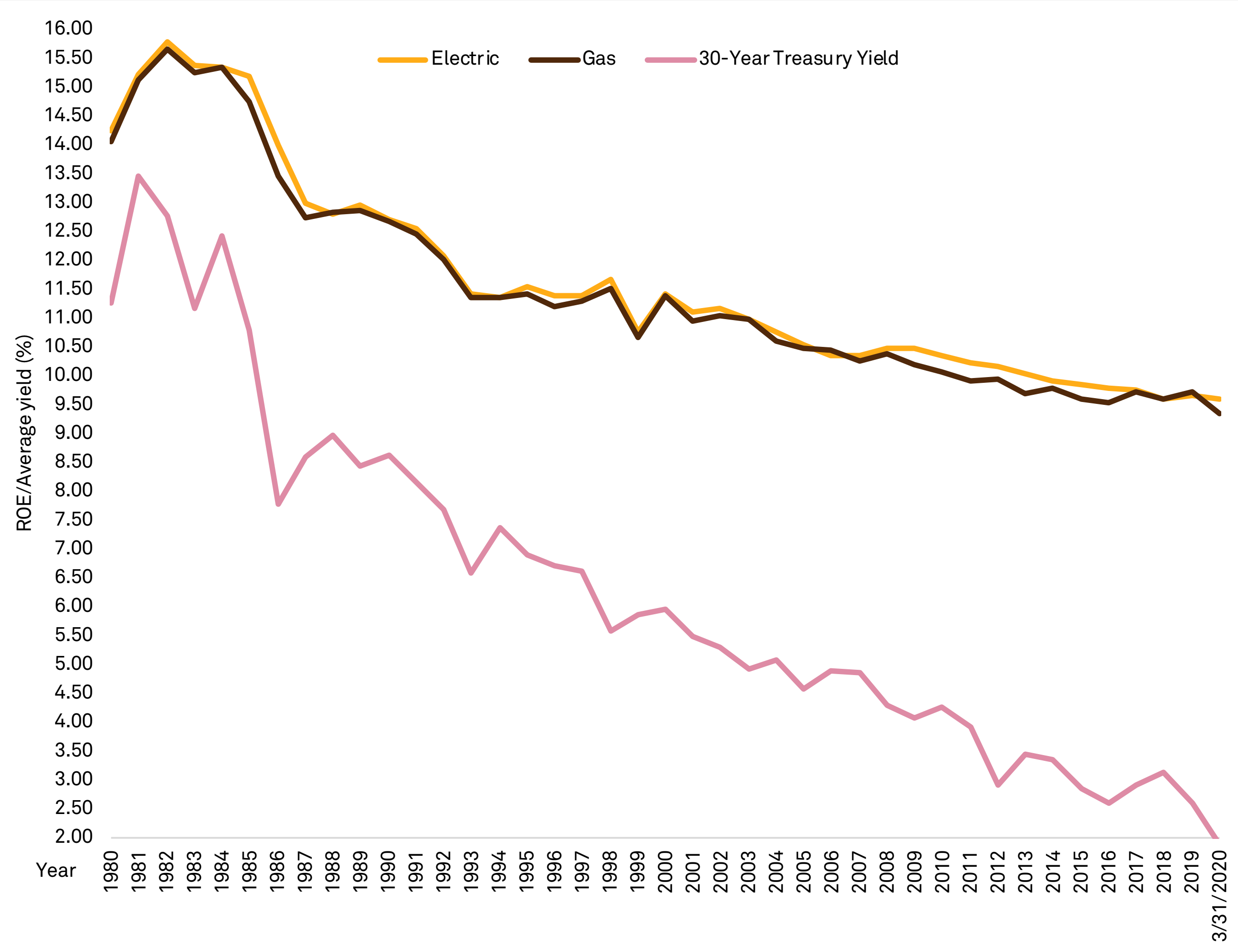
ROE is perhaps the single most litigated issue in any rate case. There are two ROE related issued that RRA considers when evaluating an individual rate case and the overall regulatory environment: (1) how the authorized ROE(s) compares to the average of returns authorized for energy utilities nationwide over the 12 months or so immediately preceding the decision; and (2) whether the company has been accorded a reasonable opportunity to earn the authorized return in the first year of the new rates.

With regard to the first criterion, RRA looks at the ROEs historically authorized utilities in a given state and compares them to utility industry averages, as calculated in RRA's Major Rate Case Decisions Quarterly Updates . When referring to these "averages," RRA means the average ROE approved in cases decided in a particular year; returns carried over from prior years are not included in the averages.

Intuitively, authorized ROEs that meet or exceed the prevailing averages at the time established are viewed as more constructive than those that fall short of these averages. However, ROEs overall have been declining steadily since 1980, falling below 10% in for the first time in 2011 for gas utilities and 2014 for electric utilities, and remaining below that benchmark since.

Interest rates have been a key factor driving authorized ROEs downward, but commission determinations that various alternative or innovative ratemaking mechanisms have reduced risk for the companies and their investors across the board have played a role as well.

Average authorized ROE in the US/30-year treasury bond yields
Calendar years 1980-2019,Q1'20



Data compiled as of May 19, 2020.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Consumer advocacy organizations continue to argue that lower returns on equity are warranted because of risk-reducing factors, such as limited-issue riders, decoupling mechanisms, alternative regulation constructs and changes to basic rate design.

This presents a stark contrast to views held by both fixed-income and equity investors that utilities are becoming more risky because of large capital spending plans, limited sales growth potential, changes in the structure of the industry and the regulatory framework occasioned by new technologies and the public policy shift favoring renewable resources, federal tax reform impacts, interest rate volatility and now the challenges being posed by overall market volatility as the coronavirus pandemic drags on.

With regard to the second consideration, in the context of a rate case, a utility may be authorized a relatively high ROE, but factors such as capital structure changes, the age or "staleness" of the test period, rate base and expense disallowances, the manner in which the commission chooses to calculate test year revenue, and other adjustments may render it unlikely that the company will earn the authorized return on a financial basis.

With respect to capital structure, most commissions utilize the company's actual capital structure at a given point in time, but in some instances the commission may rely on a hypothetical capital structure that represents a mix of debt and equity that the commission views as more reasonable or economically efficient. If the commission uses a capital structure that is more highly leveraged that the company's actual structure, this will lower the overall return authorized and the revenue requirement ultimately approved, and may render it more difficult for the company to earn the authorized return on its actual equity.

Even if a utility is accorded a "reasonable opportunity" to earn its authorized ROE, there is no guarantee that the utility will do so. The revenue requirement and ROE established in a rate case are targets that the commission believes the established rates will allow the utility to attain.

Various factors such as weather, management efficiency, unexpected events, demographic shifts, fluctuations in economic activity and customer participation in energy conservation programs may cause revenue and earnings to vary from the targets set.

Hence, the overall decision may be restrictive from an investor viewpoint even though the authorized ROE is equal to or above the average. For a more detailed discussion of the rate case process, refer to the RRA report entitled The Rate Case Process: A Conduit to Enlightenment.

Accounting

RRA looks at whether a state commission has permitted unique or innovative accounting practices designed to bolster earnings. Such treatment may be approved in response to extraordinary events such as storms or for volatile expenses such as pension costs. Generally, such treatment involves deferral of expenditures that exceed the level of such costs reflected in base rates. In some instances the commission may approve an accounting adjustment to temporarily bolster certain financial metrics during the construction of new generation capacity.

From time to time, commissions have approved frameworks under which companies were permitted to, at their own discretion, adjust depreciation in order to mitigate underearnings or eliminate an overearnings situation without reducing rates. These types of practices are generally considered to be constructive from an investor viewpoint.

Federal tax law changes enacted in 2017 and effective in 2018, particularly the reduction in the corporate federal income tax rate to 21% from 35%, had sweeping impacts on utilities, with a flurry of ratemaking activity during 2018 and 2019. While the issues have been addressed for most of the RRA-covered companies, there are still some that have not.

For most of the companies that have already addressed the implications with regulators, rates have been reduced to reflect the ongoing impact of the lower tax rate, refunds to return to ratepayers related deferred over-collections are occurring over a relatively short time period and amortization of the related excess accumulated deferred income tax liabilities is occurring over varying time periods — generally over the lives of the companies' assets for protected amounts and most often five to 10 years for unprotected amounts. RRA has been monitoring these developments and their impact on credit ratings and investor risk.

The ongoing COVID-19 pandemic and how the related costs are categorized and recovered will be something RRA will be focusing on in the coming months.

Alternative regulation

Generally, RRA views as constructive the adoption of alternative regulation plans that are designed to streamline the regulatory process and cost recovery or allow utilities to augment earnings in some way. These plans can be broadly or narrowly focused. Narrowly focused plans may: allow a company or companies to retain a portion of cost savings relative to a base level of some expense type, e.g., fuel, purchased power, pension cost, etc.; permit a company to retain for shareholders a portion of off-system sales revenues; or provide a company an enhanced ROE for achieving operational performance and/or customer service metrics or for investing in certain types of projects, e.g., demand-side management programs, renewable resources, new traditional plant investment.

Select alternative regulation plans in the US[1]

Formula-based ratemaking	Multi-year rate plans	Earnings sharing	Incentive ROEs	Electric fuel/ Gas costs	Capacity release/ Off-system sales
Alabama	California	Alabama	Colorado	Indiana	Colorado
Arkansas	Connecticut	Arkansas	Iowa	Idaho	Delaware
Georgia	Dist. of Columbia[2]	Connecticut	Kansas[2]	Iowa	Florida
Hawaii	Florida	Florida	Mississippi	Illinois	Indiana
Illinois	Georgia	Georgia	Montana[2]	Kansas	Iowa
Louisiana—NOCC	Hawaii	Hawaii	Nevada	Kentucky	Kentucky
Louisiana—PSC	Louisiana—NOCC	Idaho	Ohio	Maryland	Louisiana
Maine	Maine	Iowa	Virginia	Missouri	Massachusetts
Massachusetts	Maryland[2]	Kansas	Washington[2]	Montana	Missouri
Minnesota	Massachusetts	Louisiana—NOCC	Wisconsin	New Jersey	New Jersey
Mississippi	Minnesota	Louisiana—PSC		Oregon	New York
Pennsylvania[2]	New Hampshire	Maine		Tennessee	North Dakota
Tennessee	New York	Massachusetts		Rhode Island	New Jersey
Texas—RRC	Ohio	Mississippi		Utah	Oklahoma
Vermont	Pennsylvania[2]	Nevada		Vermont	Pennsylvania
	Rhode Island	New Mexico		Virginia	Rhode Island
	South Carolina	New York		Wyoming	South Dakota
	Utah	Oklahoma			Tennessee
	Vermont	Oregon			Texas—PUC
	Washington[2]	Rhode Island			Texas—RRC
	Wisconsin	South Dakota			Utah
		Vermont			
		Virginia			
		Washington			
		Wisconsin			

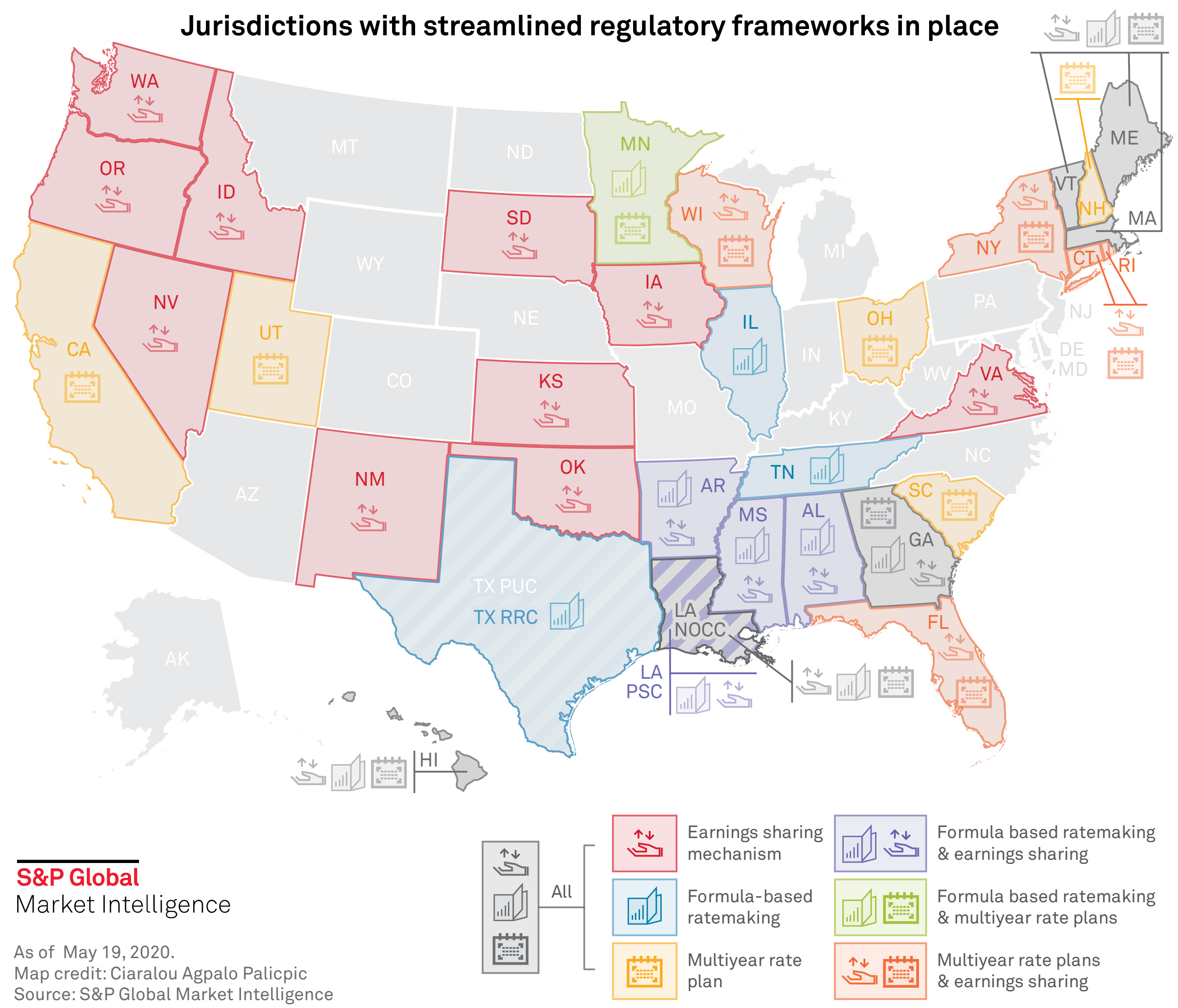
As of May 19, 2020.
NOCC=New Orleans City Council; PSC=Public Service Commission; PUC=Public Utility (ies) Commission; RRC=Railroad Commission.
[1]Mechanism in place for at least on utility in the state, unless otherwise noted.
[2] Specifically permitted by rule, law or commission order; no mechanism currently in place.
Source: Regulatory Research Associates, a group withinn S&P Global Market Intelligence.

The use of plans with somewhat broader scopes, such as ROE-based earnings sharing plans, is, for the most part, considered to be constructive, but it depends upon the level of the ROE benchmarks specified in the plan and whether there is symmetrical sharing of earnings outside the specified range.

Some states employ even more broad-based plans, known as formula-based ratemaking. Formula-based ratemaking plans generally refer to frameworks where the commission established a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost or service base rate proceeding. Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or period of years.

Others use multiyear rate plans, under which the commission approves a succession of rate changes that are designed to take into account anticipated changes in revenues, expenses and rate base. The commission may approve a static authorized ROE or the plan may provide for adjustments to the ROE during the plan's term. These plans often include true-up mechanisms to ensure that the company makes the investments it has committed to make at the inception of the plan. The plans often include earnings sharing mechanisms and may also include performance-based ratemaking provisions.

Jurisdictions with streamlined regulatory frameworks in place



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As of May 19, 2020.
Map credit: Ciaralou Agpalo Palicpic
Source: S&P Global Market Intelligence

Court actions

This aspect of state regulation is particularly difficult to evaluate. Common sense would dictate that a court action that overturns restrictive commission rulings is a positive. However, the tendency for commission rulings to come before the courts and for extensive litigation as appeals go through several layers of court review may add an untenable degree of uncertainty to the regulatory process. Also, similar to commissioners, RRA looks at whether judges are appointed or elected, as political considerations are more likely to influence elected jurists.

Legislation

While RRA's Commission Profiles provide statistics regarding the make-up of each state legislature, RRA has not found a specific correlation between the quality of energy legislation enacted and which political party controls the legislature. Of course, in a situation where the governor and legislature are of the same political party, generally speaking, it is easier for the governor to implement key policy initiatives, which may or may not be focused on energy issues.

Key considerations with respect to legislation include: how proscriptive newly enacted laws are; whether the bill is clear or ambiguous and open to varied interpretations; whether it balances ratepayer and shareholder interests rather than merely "protecting" the consumer; and whether the legislation takes a long-term view or is a "knee-jerk" reaction to a specific set of circumstances.

Legislative activity impacting utility regulatory issues has been robust in recent years, as state policymakers, utilities and industry stakeholders seek to address "disruptors" that challenge the traditional regulatory framework. RRA follows these developments closely with an eye toward assessing whether the states are taking a balanced, sustainable approach and how legacy utility providers will be affected by the policies being adopted.

Corporate governance

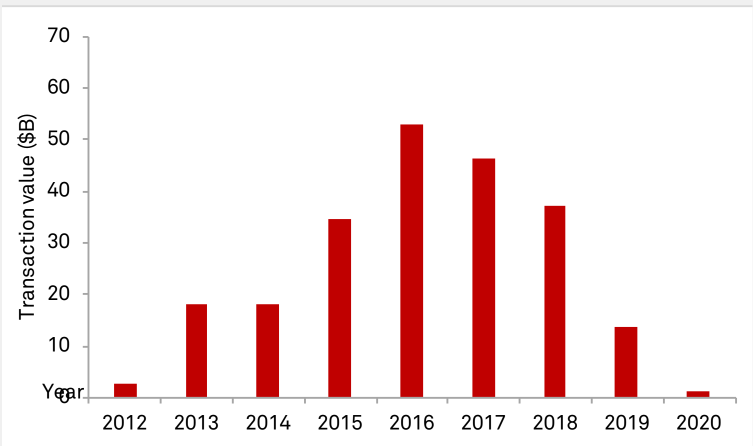
The term corporate governance generally refers to a commission's ability to intervene in a utility's financial decision-making process through required preapproval of all securities issuances, limitations on leverage in utility capital structures, dividend payout limitations, ring fencing and authority over mergers. Corporate governance may also include oversight of affiliate transactions.

In general, RRA views a modest level of corporate governance provisions to be the norm, and in some circumstances, these provisions, such as ring fencing, have protected utility investors as well as ratepayers. However, a degree of oversight that would allow the commission to "micromanage" the utility's operations and limit the company's financial flexibility would be viewed as restrictive.

Merger and acquisition activity

Though merger and acquisition activity has slowed in 2019 and 2020, it was fairly robust in prior years, with more than 40 transactions aggregating to $207 billion in transaction value announced between 2013 and 2018. Eight transactions with a total value of $14 billion were announced in 2019 and thus far in 2020, two transactions aggregating to $1 billion have been announced.

Utility mergers announced 2012-2020



Data gathered as of May 19, 2020.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

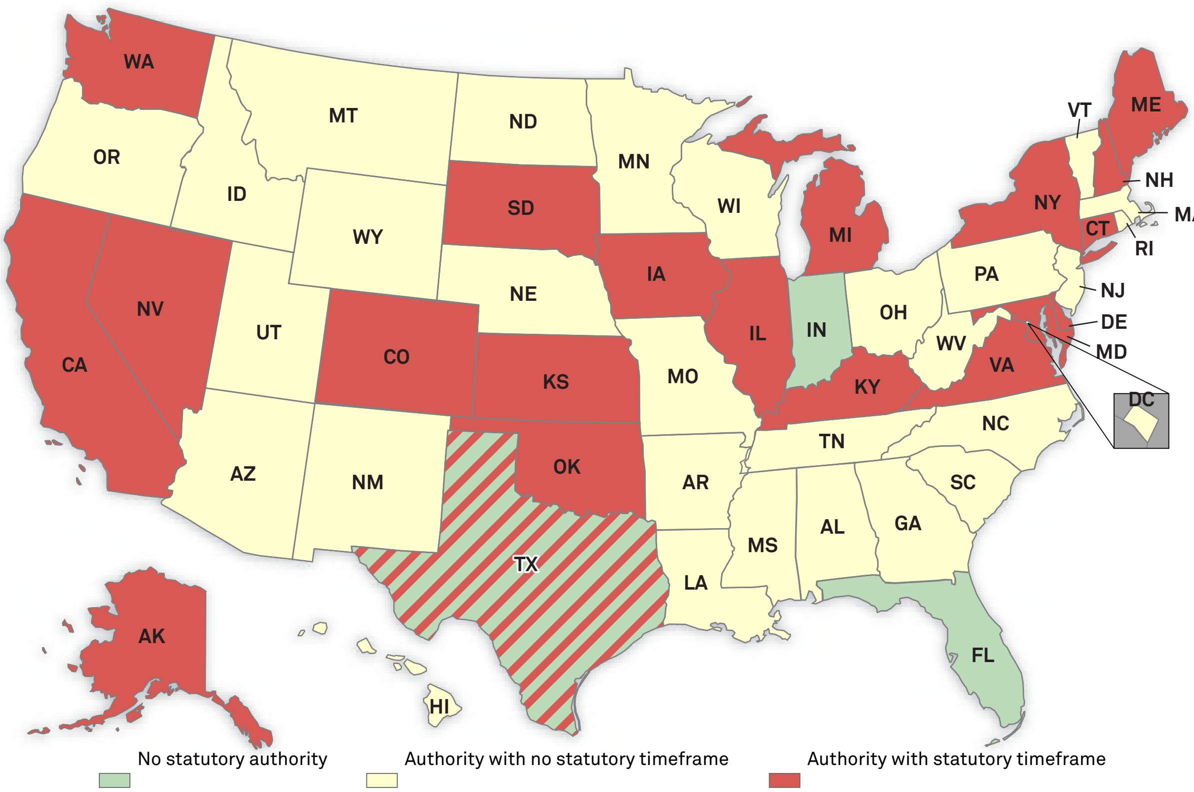
Aside from the involved entities' boards of directors and shareholders, deals involving regulated utilities must pass muster with some or all of a variety of federal and state regulatory bodies. The states generally look at the day-to-day issues such as the impact on rates, safety and reliability.

Looking more closely at the role of [state regulators], 50 of the 53 non-federal jurisdictions RRA follows have some type of review authority over proposed mergers. In Indiana and Florida, preapproval by state regulators is not required before a transaction can proceed. In Texas, prior approval by the Public Utility Commission of Texas is required before a transaction involving an electric utility can take place, but Railroad Commission of Texas approval is not required for a transaction involving a local gas distribution company.

In evaluating a commission's stance on mergers, RRA looks at several broad issues such as whether there is a statutory time frame for consideration of a transaction and how long the process actually took.

For the 50 jurisdictions where commission preapproval is required, the review process and standards vary widely. In 20 of the jurisdictions, the commission must complete a merger review within a prescribed period of time, but in the remaining jurisdictions there is no timeline for their merger reviews, which means a commission could effectively "pocket veto" a transaction by delaying a decision until the merger agreement between the applicants expires or until pursuing the transaction is no longer feasible.

Utility mergers — statutory authority



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As of May 19, 2020.
In Texas, mergers involving electric utilities are subject to commission review; mergers involving local gas distribution companies are not.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.
Map credit: Arleigh Andes

In addition, RRA considers whether a settlement was reached among the parties and, if so, whether the commission honored that settlement or required additional commitments. RRA also examines how politicized the process was: Did the governor, or in the District of Columbia the mayor, play a role? Did the transaction garner a lot of local media attention in the affected jurisdiction?

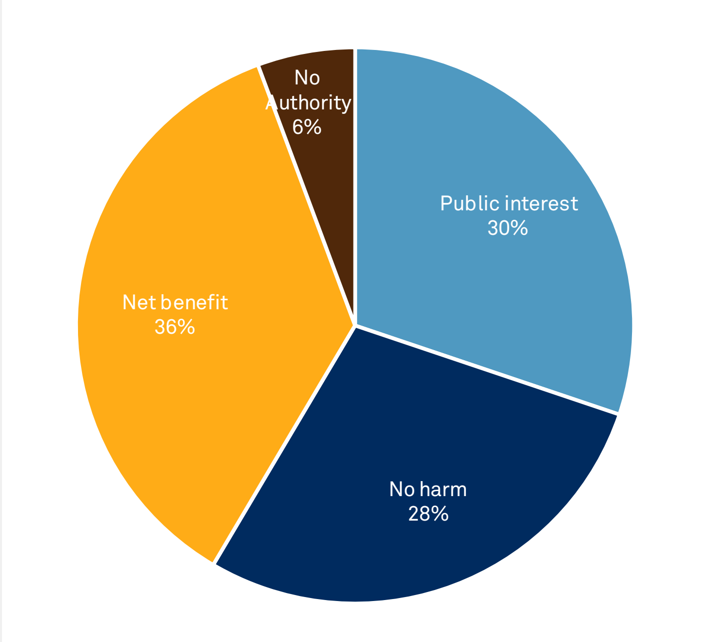
The definition of what constitutes a transaction that is subject to review can vary widely and may include sales of individual assets or a marginal minority interest as well as larger transactions where a controlling interest or the whole company is changing hands. State law often lacks specificity with respect to what constitutes a transaction that is subject to regulatory review.

In cases where the state commission has authority over mergers, RRA reviews the type of approval standard that is contained in state law and/or has been applied by the commission in specific situations.

For discussion purposes, RRA groups the statutory standards into three general buckets: public interest, which is generally thought to be the least restrictive, no net ratepayer harm, which is somewhat more restrictive, and net ratepayer benefit, which is the most restrictive.

In many instances, regulators have broad discretion to interpret what the statutes may mean by these terms. So, the standard of review is often more readily apparent by looking at how prior transactions were addressed than by reading the statutory language — one commission's public interest might be another's net ratepayer benefit.

Merger review standards



As of May 19, 2020.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

More narrowly, RRA reviews the conditions placed on the commission's approval of these transactions, including: whether the company will be permitted to retain a portion of any merger-related cost savings; if guaranteed rate reductions or credits are required that are or are not directly related to merger savings; whether certain assets were required to be divested; what type of local control and work force commitments are required; whether there are requirements for certain types of investment to further the state's public policy goals that may or may not be consistent with the companies' business models and whether the related costs will be recoverable from ratepayers; and whether the commission placed stringent limitations on capital structure and/or dividend policy or composition of the board of directors.

See the Merger Activity section of each Commission Profile for additional detail on statutory guidelines for merger reviews and detail concerning approved/rejected mergers and the associated conditions imposed.

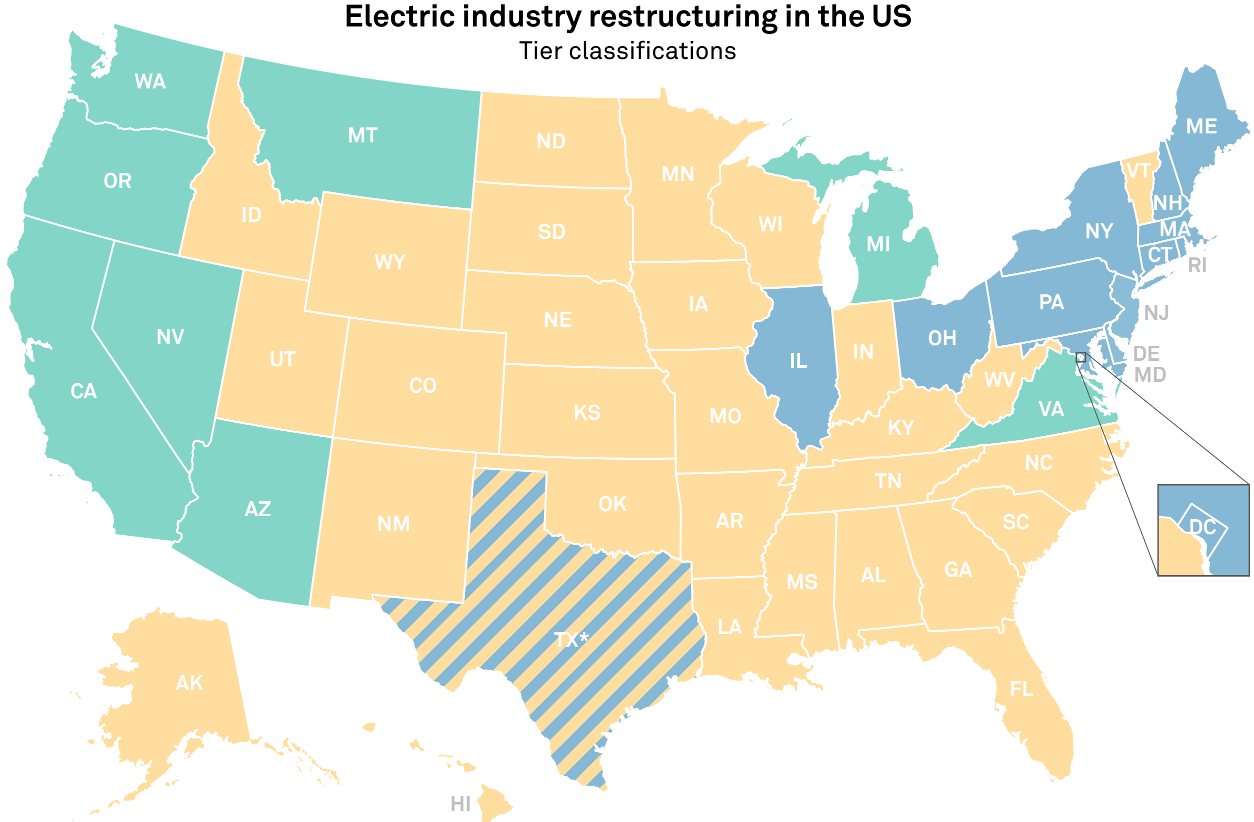
Electric regulatory reform/industry restructuring

By electric industry restructuring, RRA means implementing a framework under which some or all retail customers have the opportunity to obtain their generation service from a competitive supplier. In a movement that began in the mid-1990s, about 20 jurisdictions have implemented retail competition for all or a portion of the customers in the utilities' service territories. The last of the transition periods ended as recently as 2011, when restructuring-related rate freezes concluded for certain Pennsylvania utilities.

RRA classifies each of the regulatory jurisdictions into one of three tiers based on their relative electric industry restructuring status.

Electric industry restructuring in the US

Tier classifications



Tier 1 Power prices are competitively determined for all retail customers within the jurisdiction; both standard-offer-service and retail-access customers. Retail access is permitted for all customers. For the most part, the utilities in these jurisdictions do not own generation.

Tier 2 Retail access is permitted to at least some customers/customer classes. Competitively priced power is limited to retail access customers. Power prices for standard-offer-service customers remain regulated. For the most part, utilities remain vertically integrated.

Tier 3 Power prices are fully regulated for all retail customers. All retail customers must purchase their power from the franchised utility. Utiities are vertically integrated.

Data gathered as of May 19, 2020.
* In Texas, retail competition was implemented only within the ERCOT footprint, but within that footprint, power is competitively priced for all customers. Outside of ERCOT, power prices are regulated and the utilities are vertically integrated.
ERCOT = Electric Reliability Council of Texas Inc.
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intellgence.

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Now that transition periods are completed, RRA has focused more on how standard-offer or default service is procured for customers who do not select an alternative provider and how much, if any, market-price risk the utility must absorb.

However, initiatives are underway in Arizona and Virginia that could lead to an expansion of retail competition in those jurisdictions.

RRA is also monitoring states where initiatives are underway to revamp the way the transmission and distribution system is configured. These efforts have arisen from expansion of renewables and a focus on grid reliability/resiliency. RRA refers to this trend as electric industry restructuring phase two.

Similar to phase one, the recovery of stranded costs and ways to ensure universal service are real concerns. In phase two, the conversation is further complicated by the need to ensure not just the physical, but also the cybersecurity of the grid. Several states got out in front of these issues and are addressing them in a broad-based way, while others are taking a more piecemeal approach dealing with deployment of advanced metering, distributed generation and net metering, time-of-use rates, cybersecurity and other issues on an individual basis.

The pressure to resolve these issues is increasing, as customers and policymakers want the changes in place yesterday. As these issues unfold, the same issues that were of concern in the first phase of restructuring will warrant close attention.

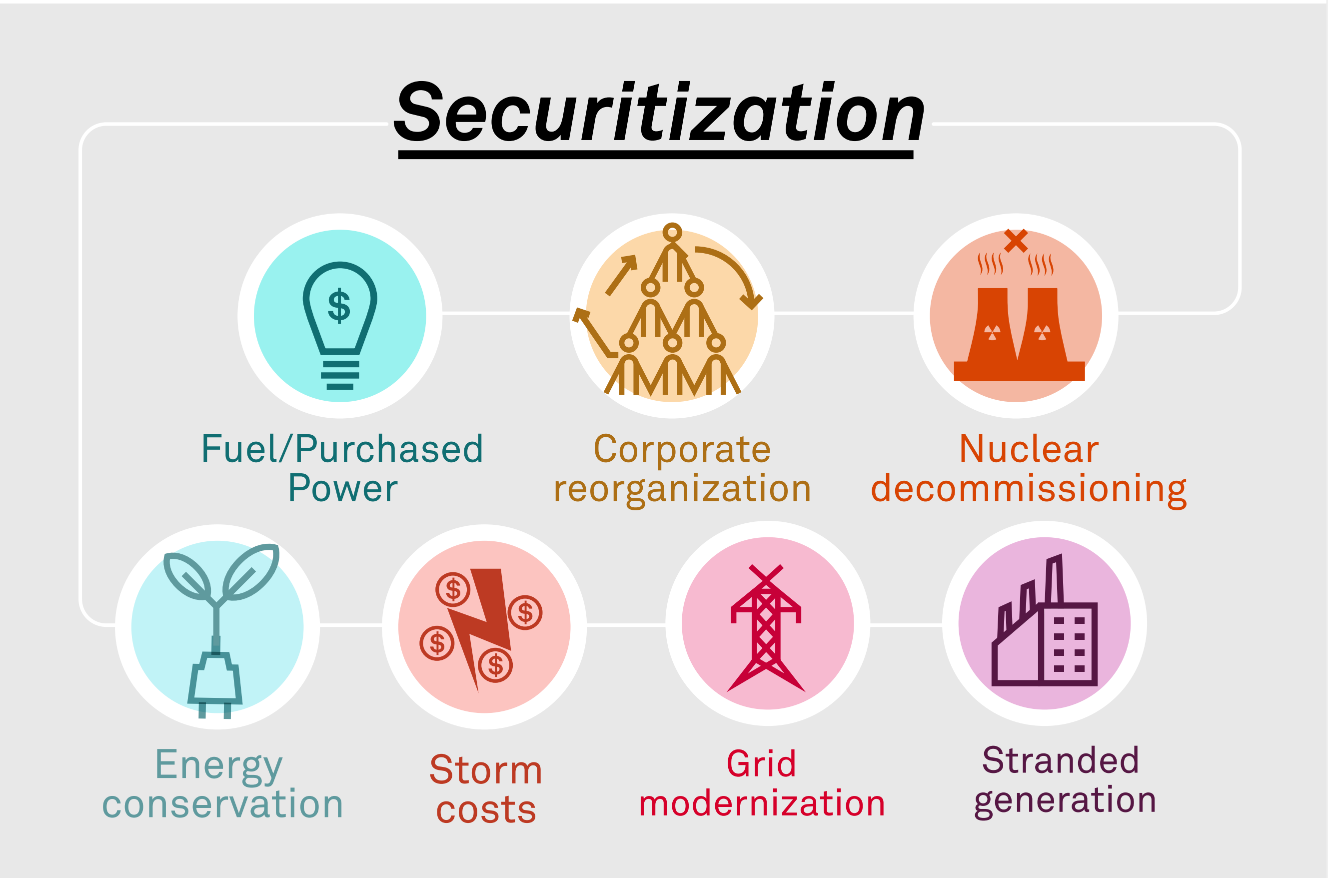
Gas regulatory reform/industry restructuring

Retail competition for gas supply is more widespread than is electric retail competition, and the transition was far less contentious as the magnitude of potential stranded asset costs was much smaller. Similar to electric retail competition, RRA generally does not view a state's decision to implement retail competition for gas service as either positive or negative from an investor viewpoint. RRA primarily considers the manner in which stranded costs were addressed and how default-service obligation-related costs are recovered.

Securitization

As it pertains to utilities, securitization refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators and/or state legislators.

Use of securitization by US utilities



Data as of May 19, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

Securitization generally requires a utility to assign the designated revenue stream to a "bankruptcy remote" special purpose entity, or SPE, or trust, which in turn issues bonds that will be serviced by the transferred revenue stream. The funds raised by the bond issuance flow to the utility, and in many cases are used to retire outstanding higher-cost debt and/or buy back common equity, thus lowering the company's weighted average cost of capital.

While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded the securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a state commission. In RRA's experience, no state commission has authorized securitization in the absence of enabling legislation.

Securitization is viewed as an attractive option because it allows regulators to minimize the customer rate impacts related to recovery of a particular utility asset. The carrying charge on the asset would be the lower interest rate applied to a highly rated, usually AAA, corporate bond rather than the utility's weighted average cost of capital or even the interest rate on typical utility bonds, which are generally rated BBB and carry higher interest rates.

At the same time, securitization simultaneously reduces the investment risk for the utility by providing the utility up front recovery of its investment in what are usually non-revenue-producing assets. The company can then redeploy those investment dollars elsewhere.

The energy industry's introduction to asset securitization occurred in the mid-1990s, when legislation was enacted in certain states enabling utilities to securitize mandated conservation investments.

In the late 1990s and early 2000s, several states that implemented retail competition for electric generation enacted legislation allowing securitization to be used for recovery of uneconomic generating or other physical assets, above-market-priced purchased power contracts, regulatory assets, nuclear decommissioning costs, etc., that had the potential to become unrecoverable, or stranded, in a fully competitive market for generation supply.

In recent years, changing industry dynamics have once again begun to raise concerns about the prospects of stranded costs and securitization is being used to address generation facilities that are retired prematurely.

Securitization has also been used as part of reorganization plans, to finance fuel/purchased power balances, distribution system improvements and extraordinary storm costs.

Adjustment clauses

Since the 1970s, adjustment clauses have been widely utilized to allow utilities to recover fuel and purchased power costs outside a general rate case, as these costs are generally subject to a high degree of variability. In some instances, a base amount is reflected in base rates, with the clause used to reflect variations from the base level, and in others, the entire annual fuel/purchased power cost amount is reflected in the clause.

Over time, the types of costs recovered through these mechanisms were expanded in some jurisdictions to include such items as pension and healthcare costs, demand-side management program costs, Federal Energy Regulatory Commission-approved regional transmission organization costs, new generation plant investment, and transmission and distribution infrastructure spending.

RRA generally views the use of these types of mechanisms as constructive but also looks at the frequency at which the adjustments occur, whether there is a true-up mechanism, whether adjustments are forward-looking in nature where applicable, whether a cash return on construction work in progress is permitted and whether there may be some ROE incentive for certain types of investment.

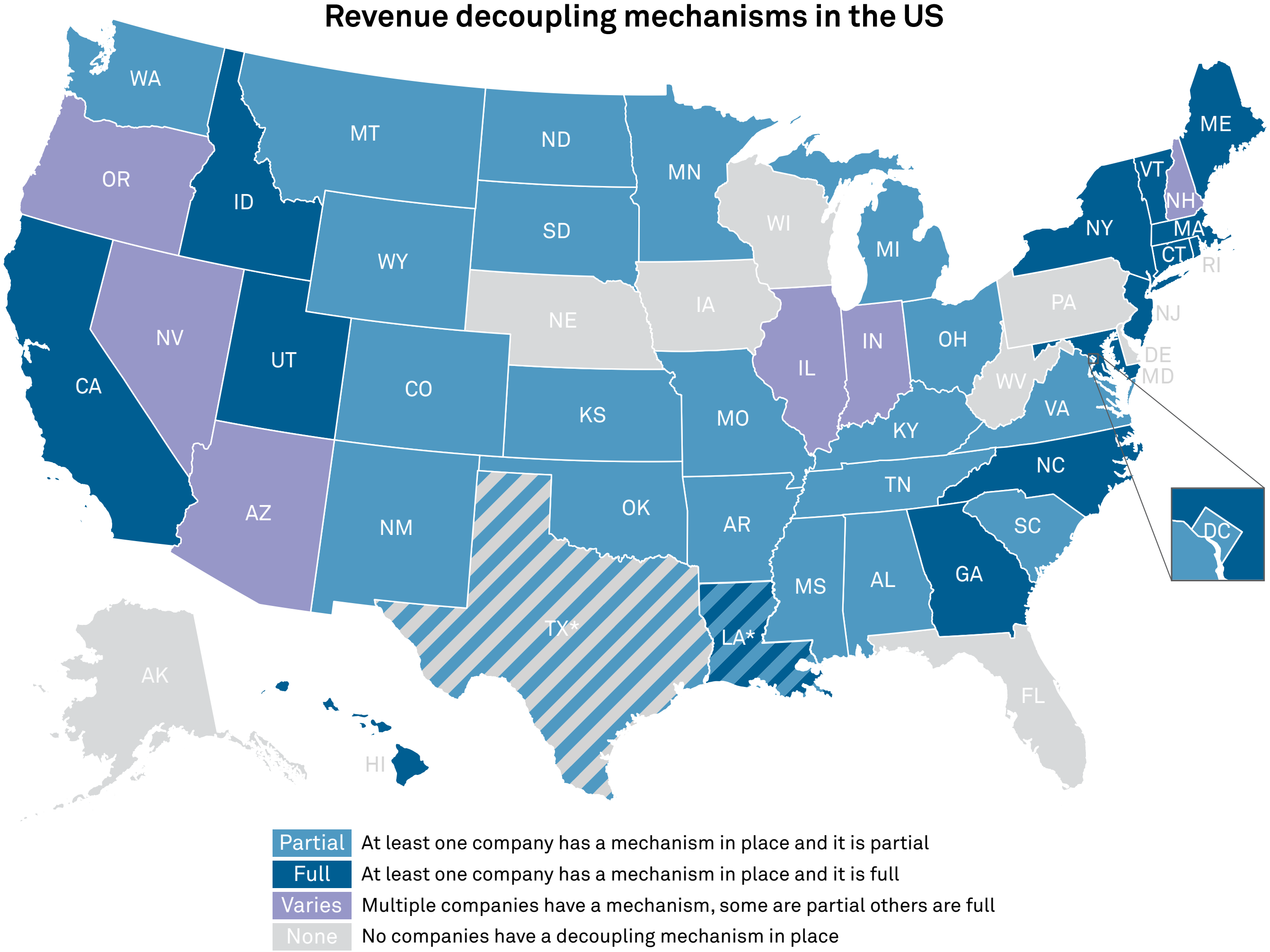
Another class of adjustment clauses, revenue decoupling mechanisms, allow utilities to adjust rates between rate cases to reflect fluctuations in revenues versus the level approved in the most recent base rate case that are caused by a variety of factors.

Some of these factors, such as weather are beyond a utility's control and the mechanism can work both ways — in other words it can allow the company to raise rates to recoup revenue losses associated with weather trends that reduce customer usage and can also require the company to reduce rates when weather trends cause usage to be higher than normal.

As energy efficiency initiatives have expanded, decoupling mechanisms have also been implemented to reduce the disincentive for utilities in pursuing energy conservation programs by making the utilities whole for reductions in sales volumes and revenues associated with customer participation in these programs.

Some of these mechanisms also allow the utility to adjust rates to reflect fluctuations in customer usage that are brought about by broader economic issues, such as demographic shifts, the migration of large commercial/industrial customers to other service areas, the shutdown of such businesses due to changes in their respective industries, recessions and theoretically, crises such as the current COVID-19 pandemic.

Revenue decoupling mechanisms in the US



As of May 19, 2020.
* In Louisiana and Texas, there are two different regulatory commissions, with differing policies.
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

RRA considers a decoupling mechanism that adjusts for all three of these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms.

Generally, an adjustment mechanism would be viewed as less constructive if there are provisions that limit the utility's ability to fully implement revenue requirement changes under certain circumstances, e.g., if the utility is earning in excess of its authorized return.

Integrated resource planning

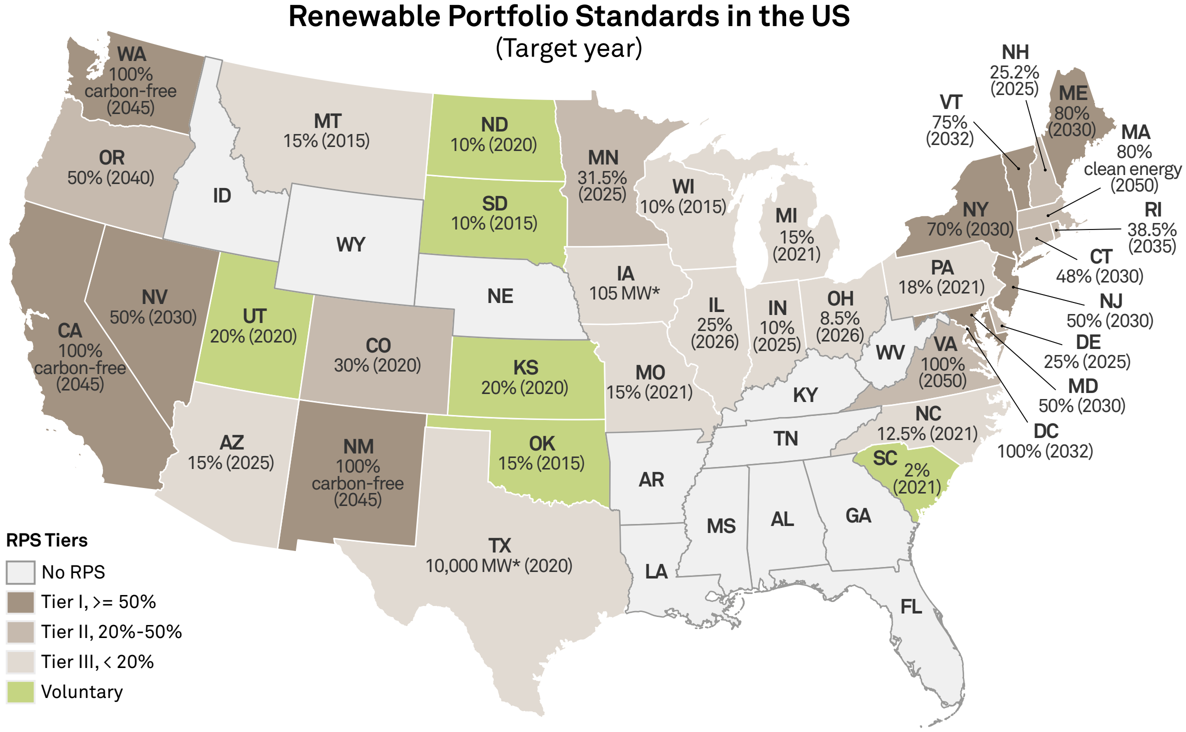
RRA generally considers the existence of a resource-planning process to be constructive from an investor viewpoint as it may provide the utility at least some measure of protection from hindsight prudence reviews of its resource acquisition decisions. In some cases, the process may also provide for preapproval of the ratemaking parameters and/or a specific cost for the new facility. RRA views these types of provisions as constructive, as the utility can make more informed decisions as to whether it will proceed with a proposed project.

Renewable energy/emissions requirements

As with retail competition, RRA does not take a stand as to whether the implementation of renewable portfolio standards, or RPS, or an emissions reduction mandate is positive or negative from an investor viewpoint. However, RRA considers whether there is a defined preapproval and/or cost-recovery mechanism for investments in projects designed to comply with these standards.

RRA also reviews whether there is a mechanism such as a rate increase cap that ensures that meeting the standards does not impede the utility's ability to pursue other investments and/or recover increased costs related to other facets of its business. RRA also looks at whether incentives, such as an enhanced ROE, are available for these types of projects.

Renewable Portfolio Standards in the US
(Target year)



As of May 19, 2020.
* Already reached.
Map credit: Jose Miguel Fidel C. Javier
Source: S&P Global Market Intelligence

In recent years, the focus on renewables has surged across the United States, with all but 12 jurisdictions developing some type of RPS. The proliferation of renewables, particularly those that are customer-sited or distributed resources, and the related rise of battery storage and electric vehicles have raised questions regarding the traditional centralized industry framework and whether that framework needs to change, perhaps ushering in a second phase of electric industry restructuring. How these changes are implemented is something RRA will be watching closely.

With respect to emissions, the threat of a federal carbon emissions standard for utilities and the spread of state-level initiatives have caused many companies to rethink legacy coal-fired generation, causing plants to be shut down earlier than anticipated. How the commissions address these “stranded costs” also poses a risk for investors and bears monitoring.

The zero-carbon movement has also caused utilities/states to re-examine investments in nuclear facilities and, in some cases, to develop programs designed to support the continued operation of those facilities even though they may not be economic from a competitive-markets standpoint. How these issues are addressed is something that RRA is also monitoring.

Rate structure

RRA looks at whether there are economic development or load-retention rate structures in place and, if so, how any associated revenue shortfall is recovered.

RRA also looks at whether there have been steps taken over recent years to reduce/eliminate interclass rate subsidies, i.e., to equalize rates of return across customer classes.

In addition, RRA considers whether the commission has adopted or moved toward a straight-fixed-variable rate design, under which a greater portion of a company’s fixed costs are recovered through the fixed monthly customer charge, thus according the utility greater certainty of recovering its fixed costs.

This is increasingly important in an environment where weather patterns are more volatile, organic growth is limited due to the economy and the proliferation of energy efficiency/conservation programs, and large amounts of non-revenue-producing capital spending is required to upgrade and strengthen the grid.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

As of May 19, 2020.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence.

In conjunction with the influx of renewables and distributed generation, the issue of how to compensate customer-owners for excess power they put back into the grid has become increasingly important and in some instances controversial. How these pricing arrangements, known as net metering, are structured can impact the ability of the utilities to recover their fixed distribution system costs and by extension their ability to earn their authorized returns.

Contributors: *Charlotte Cox, Jim Davis, Russell Ernst, Lisa Fontanella, Monica Hlinka, Jason Lehman, Dan Lowrey and Amy Poszywak*

New York Public Service Commission

General Information

Contact Information	Empire State Plaza, Agency Bldg. 3 Albany, NY 12223-1350 (518) 474-7080
	http://www.dps.ny.gov
Number of Commissioners	5 of 5
Selection Method	Commissioners: Gubernatorial appointment, Senate confirmation Chairperson: Appointed by and serves at the pleasure of the Governor
Term of Office	Commissioners: 6 years Chairperson: Indefinite
Chairperson of Commission	John B. Rhodes
Deputy Chairperson of Commission	NA
Governor	Andrew M. Cuomo (D)
Service Regulated	Cable television companies, Electric utilities, Gas utilities, Radio common carriers, Securities companies, Steam utilities, Telecommunications utilities, Water utilities
Commission Ranking	Average/1 (5/11/2017)
Commission Budget	$90 million
Commissioner Salaries	Commissioners: $109,800 Chairperson: $127,000
Size of Commission Staff	520
Company Name, Abbreviated	New York Public Service Commission's Rate Case History
Research Notes	RRA Articles
RRA Contact	Lisa Fontanella

Commissioners

PERSON'S NAME	PARTY ABBREVIATION	DATE ROLE BEGAN	TERM ENDS
John B. Rhodes Chairman	D	06/2017	02/2021
Diane Burman	R	07/2013	02/2024
James Alesi	R	06/2017	02/2021
John Howard	D	06/2019	02/2024
Tracey Edwards	D	06/2019	02/2024

RRA Ranking History

DATE OF RANKING CHANGE	COMMISSION RANKING
5/11/2017	Average / 1

DATE OF RANKING CHANGE	COMMISSION RANKING
4/16/2013	Average / 2
10/24/2007	Average / 3
10/1/2002	Average / 2
7/10/1996	Average / 3
10/19/1994	Average / 2
3/24/1987	Average / 1
7/2/1982	Average / 3

RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction’s utilities. The evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state’s utilities as a result of regulatory, legislative, and court actions.

Miscellaneous Issues

Gubernatorial election – Incumbent Gov. Andrew Cuomo, a Democrat, was re-elected on Nov. 6, 2018, to a third term commencing January 2019.

Commission membership — No more than three commissioners may be from the same party. Under state law, PSC membership may be expanded to seven.

Commission budget — Fiscal year April 2018-March 2019 — $89.7 million for FY 2019, including $5.5 million in federal funding

Services regulated — Investor- and municipally-owned electric and gas utilities; investor-owned water companies; local telephone service providers; steam utilities; cable television providers; and, radio-common carriers. In addition, the PSC has oversight of securities issuances by regulated operating utilities.

Staff Contacts

James Denn, Director, Public Affairs (518) 474-7080

(Section updated 6/17/2019)

RRA Evaluation

The New York regulatory environment is somewhat constructive from an investor viewpoint. While the PSC, in rate cases decided in recent years, has authorized electric and gas ROEs that are lower than the nationwide industry averages, for the most part, these decisions were based on multi-year settlements that incorporated increasing rate bases over the term of the plans, revenue decoupling mechanisms and deferral accounting for increases in such items as net plant, pension expense, and labor costs. Additionally, other factors in the rate-setting process, including the incorporation of fully forecasted test periods improve the utilities' opportunity to earn the authorized ROE. Regarding industry restructuring, the electric utilities, for the most part, divested their generation assets, and the companies are protected from commodity price risk, given their use of automatic mechanisms that allow timely recovery of power procurement costs from provider-of-last-resort customers. While the electric market has been restructured, the PSC, in an effort to preserve the environmental attributes of zero-emission nuclear-powered generating facilities operating within the state, has implemented a program that supports in-state nuclear power by creating a zero-emissions credit framework, to provide financial support for the units. The PSC has embarked upon an investigation, "Reforming the Energy Vision", or REV, addressing how the current regulatory paradigm is to be modified to enable electric utilities to coordinate and manage distributed energy resources. We note that implementation of paradigm changes is expected to result in new longer-term rate plans and incentive metrics for the achievement of operational and performance goals. With regard to mergers, the PSC was critical of certain merger proposals (National Grid/KeySpan and Iberdrola/Energy East); although the commission ultimately approved these transactions, significant ring-fencing measures were imposed. In May 2017, RRA performed a comprehensive audit of its regulatory rankings. The ranking accorded New York was raised as a result of this process. RRA now accords New York an Average/1 ranking, versus the previous Average/2 ranking. (Section updated 5/11/17)

Commission Staff

There are about 520 positions authorized for the fiscal year April 2018 – March 2019. The Chairman appoints directors, deputies, lawyers, administrative law judges, and special assistants, with all others selected through, and protected by, the Civil Service System. (Section updated 8/31/18)

Consumer Interest

Represented by the PSC staff, the New York Department of State's Utility Intervention Unit, and the State Attorney General. Other active groups include Multiple Intervenors — a consortium of industrial customers, the Public Utility Law Project, the American Association of Retired Persons, and various environmental advocacy groups. (Section updated 8/31/18)

Rate Case Timing/Interim Procedures

In traditional rate proceedings, the PSC generally issues a decision within 11 months of a company's initial filing. Interim or emergency rate hikes are permitted only if a utility demonstrates that its ability to raise additional capital and to maintain service would be impaired in the absence of the increase. Interim or emergency rate hikes are seldom requested. (Section updated 8/31/18)

Rate Base and Test Period

In a traditional rate case, the PSC relies on an average original-cost rate base for a fully forecasted test period. Filings must include operating results for a historical 12-month period ending not more than 150 days prior to the filing date. The company must provide forecasted results for the first 12-month period that the rates will be in effect, plus an appropriate "verifiable link" between the two periods. In the context of adopting multi-year rate plans, the PSC has allowed rate base to be updated each year.

With regard to construction-work-in-progress, or CWIP, in the 1980s, during the nuclear construction cycle, the PSC permitted a cash return on CWIP to the extent a utility's cash flow metrics were projected to be below certain standards. However, now that the regulated utilities, for the most part, no longer own generating facilities, the current construction projects, e.g., distribution facilities, are significantly less costly, and the lead time to commercial operation of these projects is considerably shorter. As a result, the CWIP issue is less of a concern than in the past. (Section updated 8/31/18)

Return on Equity

We note that in recent years, in both fully litigated and settled cases, the PSC has authorized ROEs that are among the lowest in the nation. In traditional fully litigated rate cases, the PSC relies on a combination of the discounted cash flow, or DCF, approach and the capital asset pricing model, or CAPM, to set the authorized ROE, with a weighting of two-thirds DCF and one-third CAPM. In the context of orders predicated on multi-year rate settlements, the PSC has generally authorized ROEs that included a slight premium — typically about 30 basis points — to account for investor risk associated with the multi-year plan. These plans have typically included ROE-based company/ratepayer revenue sharing mechanisms for earnings in excess of the authorized ROE (see the Alternative Regulation section). Recent multi-year plans have provided a specific authorized return that is below the initial threshold for sharing.

On Jan. 16, 2020, Consolidated Edison Co. of New York, Inc. or CECONY, a subsidiary of Consolidated Edison, was authorized an 8.8% ROE for its electric and gas operations, following adoption of a multi-year rate plan settlement. The company's steam operations are authorized a 9.3% ROE, as established in a 2014 rate case.

On March 14, 2019, the PSC adopted a multi-year rate plan settlement for Orange and Rockland Utilities, Inc., or ORU, covering the period Jan. 1, 2019, through Dec. 31, 2021, for the company's electric and gas distribution rates. The plans incorporate a 9% ROE. ORU is a subsidiary of Consolidated Edison.

On June 14, 2018, Central Hudson Gas & Electric Corp., a subsidiary of CH Energy Group, was authorized an 8.8% ROE for both its electric and gas operations as part of a three-year rate settlement.

On Jan. 24, 2017, Consolidated Edison Co. of New York, Inc. or CECONY, a subsidiary of Consolidated Edison, was authorized a 9% ROE for its electric and gas operations, following adoption of a multi-year rate plan settlement. The company's steam operations are authorized a 9.3% ROE, as established in a 2014 rate case.

On June 15, 2016, the PSC adopted three-year rate plan settlement for New York State Electric & Gas Corp., or NYSEG, and Rochester Gas & Electric Corp., or RG&E, covering the period May 1, 2016 through April 30, 2019. The rate plans incorporate a 9% ROE for the company's electric and gas operations. NYSEG and RG&E are now subsidiaries of Avangrid Inc. The ultimate parent of NYSEG and RG&E is Iberdrola SA.

On March 15, 2018, the PSC adopted a three-year electric and gas rate plan for Niagara Mohawk Power Corp., or NMP, following a joint proposal that specified a 9% ROE. NMP is a subsidiary of National Grid USA.

On April 20, 2017, the PSC authorized National Fuel Gas Distribution Corp., or NFGD, an 8.7% ROE. While most decisions before the PSC are not fully litigated and result in multiyear rate agreements, the parties to this case were unable to reach a settlement on a multi-year rate plan. NFGD is a subsidiary of National Fuel Gas.

On Dec. 15, 2016, the PSC adopted a multi-year gas joint proposal for Brooklyn Union Gas Co., or BUG, and KeySpan Gas East Corp., or KGE, providing for three year rate plans covering the period Jan. 1, 2017 through Dec. 31, 2019. The rate plans incorporate 9% ROEs. BUG and KGE are doing business as National Grid NY, but are referred to as KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island, respectively. Both companies are subsidiaries of National Grid USA. (Section updated 1/31/20)

Accounting

Historically, utilities were permitted to recover from ratepayers, on a current basis, the costs associated with the eventual decommissioning of nuclear facilities, and the amounts collected were placed in external trusts. However, as part of their electric restructuring initiatives, Niagara Mohawk Power, or NMP, New York State Electric & Gas, or NYSEG, Rochester Gas & Electric, or RG&E, and Central Hudson Gas & Electric, or CHG&E, sold their ownership interests in the Nine Mile Point Nuclear Station to Constellation Energy, and Consolidated Edison of New York, or CECONY sold its interest in Indian Point units 1 and 2 to Entergy. Additionally, RG&E sold its Ginna nuclear plant to Constellation Energy. All of the transactions included the transfer of the existing decommissioning liability and related trust funds to the purchasers.

The PSC has a history of using deferrals and other accounting measures in rate cases in order to mitigate the bill impact of approved revenue requirement increases, and to allow the utilities' to maintain earnings when faced with increases in certain expenses during the course of a multi-year rate plan. The PSC generally applies the following criteria to determine whether deferred accounting treatment is appropriate: (1) the expense is incremental to the amount allowed in current rates; (2) the incremental amount is material to earnings, and extraordinary in nature; and, (3), the utility is not over-earning. Specifically, the PSC has allowed deferrals and true-up mechanisms for: pensions; other post-employment benefits; property taxes; environmental site investigation and remediation costs; long-term debt cost rate; major storm cost reserve; non-officer management variable pay; workers compensation insurance; and, electric net utility plant — downward-only.

During 2009 and 2010, the PSC required several of the utilities to implement "austerity adjustments," essentially imputing yet-to-be-achieved cost savings to their revenue requirements in order to recognize "extraordinary harsh economic realities" being experienced by customers.

Both Brooklyn Union Gas and KeySpan Gas East have gas safety and reliability surcharges in place that allow for recovery of costs of incremental leak prone pipe. In addition, as per the company's rate plans adopted on Dec. 15, 2015, BUG and KGE are permitted to annually reconcile site investigation and remediation, or SIR, costs and for BUG a SIR surcharge, is to be in place beginning Jan. 1, 2018, to accommodate the variable costs associated with SIR projects in New York City. The surcharge is to be triggered if the reconciliation between the rate allowance and actual costs exceeds $25 million, on a cumulative basis, and is to be capped at 2% of BUG's prior year aggregate revenues (Section updated 1/10/17)

Court Actions

PSC decisions may initially be appealed to the State Supreme Court or, in certain instances, to the Appellate Division of the Supreme Court. All appeals of Supreme Court decisions are made to the Appellate Division. Certain Appellate Division appeals may be taken to the Court of Appeals, the state's highest court. State Supreme Court judges are elected on partisan ballots. Members of the Appellate Division are designated by the governor. Court of Appeals judges are appointed by the governor with the advice and consent of the Senate.

On Oct. 19, 2016, several electric generators, including Dynegy and NRG Energy, and others filed a lawsuit with the U.S. District Court for the Southern District of New York protesting the nuclear subsidies approved by the PSC, as part of the state's Clean Energy Standard, or CES. The petitioners allege that the subsidies intrude on the exclusive authority of the Federal Energy Regulatory Commission over the sale of electric energy at wholesale in interstate commerce, under the Federal Power Act, or FPA, and therefore, request that the Court find the subsidies to be invalid and withdrawn from the CES order.

An appeal of the PUC's 2017 rate case order for National Fuel Gas is pending before the Appellate Division of the Supreme Court. In the appeal, National Fuel Gas alleges that the PSC has treated the company "in a different manner from its peers" and PSC's rulings on several matters, including equity ratio and earnings sharing, have deviated from standard commission policy. (Section updated 8/31/18)

Alternative Regulation

Rate plans

The PSC has a long history of adopting multi-faceted, multi-year rate plans. Most of the major utilities are operating under plans that include earnings sharing provisions, with earnings in excess of an established ROE cap to be shared by stockholders and ratepayers, as well as the potential for penalties related to service quality and customer service. Additionally, the plans generally include expense reconciliation mechanisms that allow the utilities to defer increases in certain expenses so long as the company's earned ROE remains below specified thresholds (see the Accounting section). If a rate plan expires before the implementation of a replacement plan, the final-year provisions of the latest plan continue to apply. Generally, the PSC imputes a productivity adjustment, which typically has been calculated as 1% of total labor expenses, all employee benefits and payroll taxes. The latest plans for the New York utilities are described briefly below.

Consolidated Edison Co. of New York, Inc., or CECONY — On Jan. 16, 2020, the PSC approved a three-year electric and gas rate plan for CECONY, covering Jan. 1, 2020, through Dec. 31, 2022. The plan includes earnings sharing provisions under which actual earnings above a threshold ROE are to be shared with customers. Specifically, incremental earnings between a 9.3% ROE and a 9.8% ROE are to be shared equally by ratepayers and shareholders; incremental earnings between a 9.8% ROE and a 10.3% ROE are to be allocated 75%/25% to ratepayers and shareholders; and incremental earnings in excess of a 10.3% ROE are to be allocated 90%/10% to ratepayers and shareholders. In addition, the joint proposal permits CECONY to earn incentives for electric and gas energy efficiency and other potential incentives. The company is subject to penalties if certain performance targets related to reliability, safety and other matters are not met. The joint proposal reflects a productivity adjustment ranging from 1% to 2% over the three-year rate plan as well as an imputation for "business cost optimization" savings.

Orange and Rockland Utilities, Inc., or ORU — On March 14, 2019, ORU adopted a three-year electric and gas rate plan for ORU covering the period Jan. 1, 2019, through Dec. 31, 2021. The revenue requirement specified in the plan is based upon a 9% ROE. The approved joint proposal includes earnings-sharing provisions under which actual earnings between a 9.6% and 10.2% ROE are to be shared equally by ratepayers and shareholders. Incremental earnings between a 10.2% and 10.8% ROE are to be allocated 75% to ratepayers and 25% to shareholders, and incremental earnings in excess of a 10.8% equity return are to be shared 90% with ratepayers 10% with shareholders. As per the approved joint proposal, ORU is to apply 50% of its portion of electric and gas shared earnings and all of the customers' portion of electric and gas shared earnings first to reduce deferred undercollections of site investigation and remediation costs and then to reduce other deferred costs.

Central Hudson Gas & Electric Corp., or CHG&E — On June 14, 2018, the PSC approved a three-year electric and gas rate plan for CHG&E, covering the period July 1, 2018 through June 30, 2021. The revenue requirement specified in the plan is based on an 8.8% ROE; incremental actual earnings between a 9.3% and 9.8% equity return are to be shared equally between customers and shareholders. Earnings between a 9.8% and 10.3% equity return would be allocated 80% to customers and 20% to shareholders, and earnings in excess of a 10.3% equity return would be allocated 90% to customers and 10% to shareholders. The earnings sharing provisions are to remain in place until a new rate plan is adopted by the PSC.

New York State Electric & Gas Corp. (NYSEG)/Rochester Gas and Electric Corp. (RG&E) — For the period May 1, 2016 through April 30, 2019, NYSEG and RG&E are subject to rate plans under which earnings above a threshold ROE are to be shared with customers. Specifically, in rate year one, incremental earnings between a 9.5% and a 10% ROE are to be shared equally by ratepayers and shareholders; incremental earnings between a 10% and a 10.5% ROE are to be allocated 75%/25% to ratepayers and shareholders; and, incremental earnings in excess of a 10.5% ROE are to be allocated 90%/10% to ratepayers and shareholders.

In rate year two, incremental earnings between a 9.65% and a 10.15% ROE are to be shared equally by ratepayers and stockholders, incremental earnings between a 10.15% and a 10.65% ROE are to be shared 75%/25% by ratepayers and stockholders and incremental earnings in excess of a 10.65% ROE are to be allocated 90%/10% to ratepayers and stockholders. In rate year three, incremental earnings between a 9.75% and 10.25% ROE are to be allocated equally to ratepayers and shareholders, incremental earnings between a 10.25% and a 10.75% ROE are to be shared 75%/25% by ratepayers and shareholders, and incremental earnings in excess of a 10.75% ROE are to be shared 90%/10% by ratepayers and shareholders. The earnings sharing mechanism, or ESM, in effect in rate year three is to continue until new rates are adopted by the PSC in a subsequent proceeding.

Niagara Mohawk Power Corp., or NMP — On March 15, 2018, the PSC approved a three-year electric and gas rate plan for NMP, covering the April 1, 2018, through March 31, 2021 period. The plan contains graduated earnings sharing provisions that begin at a 9.5% ROE. Specifically, incremental earnings between a 9.5% ROE and a 10% ROE are to be shared equally by ratepayers and shareholders; incremental earnings between a 10% ROE and a 10.5% ROE are to be allocated 75%/25% to ratepayers and shareholders; and, incremental earnings in excess of a 10.5% ROE are to be allocated 90%/10% to ratepayers and shareholders.

Brooklyn Union Gas Co., or BUG/KeySpan Gas East Corp., or KGE — BUG and KGE are subject to rate plans covering the three-year period Jan. 1, 2017 through Dec. 31, 2019. The rate plans include earnings sharing provisions, under which actual earnings above a threshold ROE are to be shared with customers. Specifically, incremental earnings between a 9.5% ROE and a 10% ROE are to be shared equally by ratepayers and shareholders; incremental earnings between a 10% and a 10.5% ROE are to be allocated 75%/25% to ratepayers and shareholders; and incremental earnings in excess of a 10.5% ROE are to be allocated 90%/10% to ratepayers and shareholders. If the companies do not file for new rates to take effect on or before July 1, 2020, 100% of any earnings over a 9% ROE are to be deferred for ratepayers' benefit beginning on Jan. 1, 2020. The approved joint proposal incorporates productivity adjustments of 2% in rate year 1 and 1.5% in rate years 2 and 3 for BUG and KGE. The productivity adjustments are intended to capture unspecified gains in productivity and decreases in O&M expense expected to result from the increased capital expenditures and other improvements in the companies' gas systems.

National Fuel Gas Distribution Corp., or NFGD — A PUC decision issued in April 2017, in a fully-litigated rate case called for NFGD to be subject to an earnings sharing mechanism effective April 1, 2018, if the company did not file for new rates to become effective by the fourth quarter of 2018. A rate case was not filed, as such, the company is subject to an earnings sharing mechanism under which earnings above a 9.2% ROE are to be shared equally by ratepayers and shareholders.

Reforming the Energy Vision Proceeding

The PSC is conducting an investigation, "Reforming the Energy Vision", or REV, addressing how regulatory practices could be modified to enable electric utilities to manage and coordinate distributed energy resources, or DER, and enable customers to optimize their energy resource decisions, provide system benefits, and be compensated for providing such benefits.

The REV initiative proceeded along two tracks, and in February, 2015, the PSC issued a Track 1 order adopting a regulatory policy framework and implementation plan. Track 1 addressed the functions of the "distribution system platform", or DSP, providers including: undertaking an integrated approach that considers all energy resources (including energy efficiency, demand reduction, and distributed generation) in utility planning and operations (as opposed to a silo approach of evaluating these resources) to help optimize resource deployment to meet customer reliability needs and reduce overall costs to customers; upgrading distribution management systems and communications infrastructure and providing a platform to accommodate distributed energy resources, or DER, to offer new energy products and services; and, creating pricing mechanisms to buy/sell products/services from DER to provide value to the utility system and thus to customers.

Track 1 also addressed factors that may affect customer participation, whether the DSP should be the incumbent utility or an independent entity, which products and services the DSPs will purchase from DER providers, whether the utilities should be permitted to own/control DER, and how to maximize customer engagement.

In May 2016, the PSC issued a Track 2 order adopting a policy framework on ratemaking and utility business models. The order outlines four ways for utilities to achieve earnings: traditional cost-of-service earnings; earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; earnings from market-facing platform activities; and, transitional outcome-based performance measures.

With respect to the transitional measures, the PSC established earnings adjustment mechanisms, or EAMs, which are incremental performance incentives that the state's utilities can earn in return for advancing REV objectives to increase efficiencies, advance the deployment of distributed energy resources, and support the state's clean energy agenda. EAMs are to vary by utility and are required to be filed within the context of rate cases. The PSC indicated that EAMs should be outcome-based and generally be positive only.

Following the track 2 order, the PSC has approved various electric EAMs tied to system efficiency, energy efficiency, and carbon reduction within the context of rate proceedings for CECONY, NMP, CHG&E and ORU. The PSC also adopted energy efficiency EAMs for the aforementioned utilities' gas operations as well.

Other incentives

In addition to ESMs and EAMs, other types of incentive mechanisms employed in the state include: positive revenue adjustments and shared saving-type mechanisms. Positive revenue adjustments reward utilities for meeting certain goals related to gas safety and the reduction of terminations/uncollectibles. Shared saving mechanisms include incentives tied to non-wire alternatives, non-pipe alternatives, property tax reductions, off-system sales and capacity release.

Service quality

The state's electric and gas utilities have negative revenue adjustments if certain metrics tied to safety, reliability and customer service are not maintained. (Section updated 2/20/20)

(Section updated 2/20/20)

Legislation

The New York Legislature, a bicameral body, convenes annually in January. In 2019, the legislature was in session from Jan. 9 through June 19. In the Senate, there are 40 Democrats and 23 Republicans in the Senate. In the House, there are 106 Democrats, 43 Republicans, and 1 independent. Bills introduced in odd-numbered years are carried over to even number years.

On July 18, 2019, Gov. Andrew Cuomo, signed into law the New York State Climate Leadership and Community Protection Act establishing a framework for reducing greenhouse gas emissions, increasing renewable electric generation and increasing energy efficiency. In addition, the law contains other socially responsible environmental, social and governance-type provisions geared toward "disadvantaged communities."

The law requires the PSC to establish a renewable energy program by June 30, 2021, that requires a minimum of 70% of statewide electric generation from the state's load-serving entities be generated by renewable energy systems by 2030. In addition, the law mandates that by 2040, emissions from the electric sector be eliminated.

Under the new law, the PSC is to establish programs that require the state's load-serving entities to meet the following procurement targets: at least 6 GW of photovoltaic solar generation by 2025; at least 3 GW of statewide energy storage capacity by 2030; and at least 9 GW of offshore wind by 2035.

The 2020 legislative session commences on Jan. 8. (Section updated 10/31/19)

Corporate Governance

The PSC has authority over securities issuances by the state's utilities and mergers and acquisitions involving these entities. In the most recent orders approving merger requests, the PSC has adopted a variety of provisions that protect the utility, and ultimately the customer, from other-than-arm's-length relationships with affiliates (see the Merger Activity section). Additionally, state law provides for each electric and gas utility to undergo a management audit every five years. Also, as a result of the PSC's expanded enforcement powers, the commission is conducting periodic operational audits.

In 2010, the PSC rejected Entergy's proposed spinoff of its nuclear operations (Indian Point 2 and 3, and Fitzpatrick) to a new company named Enexus Corporation. The PSC indicated that the company's petition was not in the public interest, and would not meet the commission's "no net harm" standard. The PSC remained concerned that Entergy will, in the future, seek to implement "other financial transactions which may not trigger the specific provisions of [public service law that requires a PSC review], but which may be harmful to the financial strength of the New York nuclear assets. In that event, Entergy might conclude that no notice to us of the proposed transaction is necessary. To assure that adequate notice of such transactions is provided, we are instituting a new proceeding [Case No. 10-E-0402] to identify the circumstances when such notice must be provided and to describe the content and details of such notice." The PSC indicated that several strategic alternatives had been suggested by Entergy, including a financial restructuring, ring-fencing the utilities, and leveraging the parent company, and the commission stated that implementation of any of these strategies could have negative credit-rating implications. In a 2011 order, the commission provided Entergy notice of its reporting requirements relative to actions that Entergy may take. No further actions by Entergy have been taken.

In 2013, the PSC approved, with conditions, a request by Iberdrola to reorganize its U.S. corporate structure. Iberdrola, the parent of utilities New York State Electric & Gas, or NYSEG, and Rochester Gas and Electric Corp., or RGE, reorganized in November 2013, by centralizing its presence in each country of operation under one country specific subsidiary holding company, thus more closely linking NYSEG and RGE to Iberdrola affiliates that operate in competitive U.S. markets. The PSC adopted requirements that separate the utilities from potential financial risks associated with competitive affiliates, and added conditions to improve transparency and access to company books and records. Additionally, the utilities were required to begin registering debt issuances with the Securities and Exchange Commission when market conditions become cost effective.

As part of a rate plan adopted by the PSC for Consolidated Edison Co. of New York, Inc., or CECONY, on Jan. 16, 2020, the PSC adopted ring-fencing provisions that call for the company to report to the PSC whenever CECONY's parent, Consolidated Edison Inc.'s, investments in non-utility businesses or whenever its debt reaches or exceeds certain thresholds. Specifically, if at the end of any semiannual period ending June 30 and Dec. 31, ConEd's investment in its nonutility business exceeds 15% of its total consolidated revenues, assets or cash flow, or if the ratio of holding company debt to total consolidated debt exceeds 20%, CECONY is to notify the PSC. Within 60 days of such notification, CECONY is required to submit a ring-fencing plan or would be required to demonstrate why additional ring-fencing measures are not necessary. (Section updated 1/31/20)

Merger Activity

By law, the PSC must review any requests to transfer minority interests greater than 10% to any entity or person. If the transfer is to another electric or gas corporation, the PSC must review the request no matter how small the percentage. Regarding mergers of rate-regulated utility companies in New York State, the PSC has generally applied a "net positive benefits" standard.

The PSC may approve a transaction following a determination that the terms and conditions as fixed or imposed are in the public interest. In evaluating whether a proposed transaction is in the public interest, the PSC has recently required that petitioners "show that the transaction would provide customers positive net benefits after considering the expected benefits offset by any risks or detriments that would remain after applying reasonable mitigation measures."

The commission is prohibited by law from permitting a utility to recover premiums above book value in rates, and has generally required that at least 50% of merger savings be allocated to ratepayers. The PSC has also placed various ring-fencing-type conditions upon merger approvals.

In 1998, the PSC approved the proposed merger of Long Island Lighting

Company, or LILCO, and KeySpan Energy, following a settlement. The agreement and PSC order required LILCO to implement a 3.9% gas rate reduction and a 2.5% electric rate decrease. The rates of KeySpan's gas distribution subsidiary Brooklyn Union Gas were reduced 3%. The merger was completed in 1998. KeySpan was later acquired by National Grid (see below).

In 1999, the PSC approved the merger of Consolidated Edison, or ED, and Orange and Rockland Utilities, or ORU, following a settlement. The merger was completed in 1999, and ORU became a subsidiary of ED. The companies agreed to an electric rate credit and gas rate reductions, which the Staff indicated would implicitly reflect the flow-through to ratepayers of 75% of merger savings. The approved merger agreement contained provisions regarding cost allocation, affiliate transactions, the separation of unregulated operations from utility operations, PSC access to books and records of unregulated affiliates, and standards of competitive conduct for the utility subsidiaries, the holding company and energy services affiliates. The agreement also included protections regarding the issuance of securities, dividend payment policies, prohibitions on loans, cross-default provisions, pledges and guarantees and restrictions on non-utility investments. ORU agreed to ensure that the total debt of either ORU or its utility subsidiaries would not exceed 65% of total capitalization. Specifically, ORU debt must be raised directly by ORU, and cannot be "derived" from the parent. ORU is precluded from making loans to the parent or any unregulated subsidiary, without prior authorization from the PSC.

In addition, ORU may not guarantee any obligation of affiliate Consolidated Edison of New York, or CECONY, or any unregulated affiliate, or pledge its assets as security for the indebtedness of the parent or an affiliate. With regard to dividends, ORU may not pay out more than 100% of income available for dividends calculated on a two-year rolling average basis. The dividend restriction does not apply to dividends necessary to transfer to the parent revenues from major transactions, such as asset sales, divestiture, or to dividends reducing ORU's equity ratio to a level appropriate to ORU's business risk, or to dividends necessary to transfer to ED the earnings of ORU's subsidiaries. ORU is required to certify annually to the PSC that it has retained or otherwise has access to sufficient capital to maintain and upgrade its system in order to continue the provision of reliable service. The agreement also includes specific provisions regarding transactions between affiliates and for assigning joint costs to the regulated utilities — CECONY and ORU — and to ED's unregulated subsidiaries.

In 2001, the PSC approved the proposed merger of Niagara Mohawk Power's, or NMP's, then-parent Niagara Mohawk Holdings and National Grid, and adopted a settlement that called for implementation of a ten-year rate plan in conjunction with the merger. The merger closed in the first quarter of 2002. NMP was required to reduce electric delivery charges by $160 million (8%) upon merger closing, and such charges remained stable for ten years. The company and customers were to equally share roughly $117 million of net savings. The company agreed to forego recovery of up to $850 million of nuclear-related stranded costs.

In 2002, the PSC approved the proposed merger of Energy East and RGS Energy Group in conjunction with a five-year rate settlement signed by the parties to New York State Electric & Gas', or NYSEG's, Price Protection Plan Proceeding. The merger closed in June 2002. The approved settlement required NYSEG to implement a $205 million (13%) electric revenue requirement reduction. In accordance with the settlement, savings that flowed from the merger were to be shared equally by stockholders and customers of both Rochester Gas & Electric, or RG&E, and NYSEG. (See below for information concerning Energy East's acquisition by Iberdrola).

In 2007, the PSC approved the merger of KeySpan and National Grid subject to several conditions. The merging parties immediately agreed to those conditions, and closing occurred immediately thereafter. The conditions included the following: a dividend restriction for Brooklyn Union Gas, or BUG, and KeySpan Gas East, or KSE, would be triggered by a downgrading action by one of the rating agencies to non-investment grade; no debt associated with the merger may be reflected on the books of BUG or KSE; BUG and KSE were to modify corporation by-laws to prevent a bankruptcy of National Grid from triggering a bankruptcy of BUG or KSE; and, the sale of KeySpan's Ravenswood Station to mitigate potential vertical market power (the facility was ultimately sold in 2008 to TransCanada Corp.).

In 2008, the PSC unanimously approved Iberdrola's proposed acquisition of Energy East. The merger closed later in September 2008, and the operating companies are now subsidiaries of Iberdrola USA, a subsidiary of Iberdrola. The commission largely approved conditions recommended by the PSC Staff, which had proposed 34 financial protection measures, and noted that Iberdrola had agreed to 16 of these measures that related to such issues as maintaining bond ratings and money pool participation. The PSC required that the customers of Energy East subsidiaries NYSEG and RG&E be credited with "positive benefit adjustments" totaling $275 million. NYSEG and RG&E were required to file new rate cases after 12 months; new cases were filed in 2009 and completed in 2010.

In 2011, the PSC granted Exelon's and Constellation Energy Group's petition that the commission decline to further review their proposed merger. The merger was completed in 2012. In its 2011 action, the PSC acknowledged that their authority over the merger was somewhat ambiguous due to the electric industry restructuring framework in New York. The PSC's involvement in this transaction stemmed from Constellation Energy Group subsidiary Constellation Energy Nuclear Group's majority ownership interest in the Nine Mile Point Nuclear Station Unit 1 and 2, and the R.E. Ginna Nuclear Power Plant.

In 2013, the PSC approved Fortis Inc.'s proposal to acquire CH Energy Group, or CHEG, the parent of Central Hudson Gas & Electric, or CHG&E, and the transaction closed immediately thereafter. Fortis is a Canadian holding company, with several electric and gas distribution companies in Canada, the U.S. and the Caribbean. A total of $9.25 million of synergy savings is to flow to ratepayers over the first five years after closing; $35 million of deferred regulatory assets, largely related to storm costs, are to be written off; and, CHG&E is required to contribute $5 million to a community benefit fund for economic development and low-income customer-assistance purposes. CHG&E's electric and gas rates were frozen until at least July 1, 2015. Additionally, the company's then-current rate plan's ROE threshold was reduced by 50 basis points to 10% from 10.5%. All other provisions of the company's then-rate plan, applicable to the third rate year, were to continue at least through June 30, 2015. (Section updated 11/21/16)

Electric Regulatory Reform/Industry Restructuring

Retail access was implemented in 1998 pursuant to the PSC's 1996 "Competitive Opportunities" order. The PSC did not adopt a generic policy regarding recovery of stranded investment; the commission considered this issue on a company-by-company basis, and permitted most stranded investment to be recovered. The PSC indicated a preference for, but did not require, divestiture of generation assets. In 1997 and 1998, the PSC approved company-specific implementation plans, and virtually all generation assets were divested.

The incumbent power distributors have retained the provider-of-last-resort, or POLR, obligation, and are procuring the power to meet this obligation through bilateral wholesale contracts with competitive suppliers. Several utilities have physical contracts with non-utility generators that provide a portion of their supply needs. Others have physical contracts with nuclear plants. Most of the utilities physically purchase the majority of their required energy on the New York Independent System Operator Day-ahead market. The energy provided to residential and small commercial customers is price-hedged through various financial instruments. The PSC allows the utilities to use a market supply charge to flow through variations in POLR power costs through each customer bill, on a monthly or bi-monthly basis.

In 1999, the PSC approved a plan to open to competition electric metering services, including installation and maintenance, meter reading and meter data retrieval and storage.

The PSC is reviewing the eligibility criteria for energy service companies.

The PSC is conducting an investigation, "Reforming the Energy Vision" that is reviewing the role of the utility in light of the proliferation of distributed generation resources and other market structure changes (see the Alternative Regulation section).

On Nov. 17, 2016, the PSC approved a request filed by Entergy Nuclear FitzPatrick, or ENF, and Exelon Generation Co. LLC, or ExGen, for approval of a transaction that calls for ExGen to acquire the 852-MW James A. FitzPatrick nuclear plant, and related assets, from ENF, and for the plant to continue to be subject to a "lightened regulatory regime." ENF's parent is Entergy Corp. and ExGen parent is Exelon Corp. The filing was tendered in accordance with the PSC's Aug. 1, 2016 adoption of a Clean Energy Standard that provides for 50% of electricity in New York to be procured from renewable energy sources by 2030, and for implementation of a framework to subsidize nuclear generating facilities in the state that may otherwise be retired (see the Renewable Energy and Emissions sections). (Section updated 11/21/16)

Gas Regulatory Reform/Industry Restructuring

Several years ago, the PSC espoused a policy that all local gas distribution companies, or LDCs, should exit the gas commodity business, with each utility to continue to be the gas supplier-of-last resort until it has exited the commodity business. However, all of the gas companies continue to sell gas. Recovery of gas commodity costs is addressed through semi-automatic adjustment clauses. (See the Adjustment Clauses section.)

Transportation-only service for large customers — usage greater than 5,000 DTH — has been available statewide since 1985 Following a 1996 generic order, the PSC approved plans filed by several LDCs to further open the local gas market to competition, allowing all customers to purchase gas supplies from sources other than their LDC. (Section updated 11/21/16)

Adjustment Clauses

Historically, all energy utilities used a semi-automatic fuel adjustment clause, or FAC, through which variations in fuel, gas and purchased power costs were flowed through to customers. With electric industry restructuring, however, generation was divested, and the electric companies have largely transitioned from the FAC to a market power adjustment clause, or MAC, or a commodity adjustment clause, or CAC. The MAC/CAC allows the distribution utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier. Changes in the clause are recognized in each customer bill, i.e., monthly, bi-monthly, etc. Although the incumbent distributors have retained the provider-of-last-resort obligation, the operation of the MAC/CAC insulates the distributor from any financial effects associated with changes in market prices.

The state's renewable portfolio standards program is funded by a separate non-bypassable volumetric delivery charge on all customer bills. Collection of this charge began in 2005, and is based on the estimated market price of the renewable resources, with subsequent true-ups to reflect actual costs.

Each of the electric and gas utilities in New York operates under a full revenue decoupling mechanism, or RDM. The RDMs provide for the companies to implement a rate surcharge or credit associated with a revenue shortfall or over-collection related to a predetermined revenue target. As a result, the RDMs offset the potential effect on earnings of any variation in sales, whether the variation is caused by energy efficiency, weather, or the economy. (Section updated 11/21/16)

Integrated Resource Planning

The PSC established Energy Efficiency Portfolio Standards, or EEPS in 2008, directing entities under its jurisdiction to reduce customers' electricity usage 15% by the year 2015. A goal of 7.7 million MWH of electric energy savings by 2015 was established for energy efficiency programs to be delivered by the electric utilities. Subsequently, similar goals were established for gas utilities. Approximately 100 electric and gas energy efficiency programs have been approved by the PSC. In 2011, the commission approved the continuation of most existing EEPS programs through 2015, with total funding of about $1.5 billion for electric efficiency programs and $630 million for gas programs. In January 2016, the commission authorized a 10 year, $5.3 billion Clean Energy Fund, or CEF, to be managed by the New York State Energy Research and Development Authority. The CEF is designed to achieve at least 13.4 million MMBtu of cumulative annual energy efficiency, as well as 88 million MWh of renewable energy. (Section updated 11/21/16)

Renewable Energy

In 2004, the PSC implemented a renewable energy standard calling for at least 25% of electric needs be provided from renewable resources by 2013. The standard was expanded by the PSC in December 2009 to 30% by 2015. In 2016, the commission adopted a transition from the renewable energy standard to a clean energy standard, or CES. In July 2018, the PSC adopted an offshore wind goal and in December 2018 an energy storage goal. In July 2019, legislation, referred to as the Climate Leadership and Community Production Act, or CLCPA, was enacted that codified the state’s renewable energy commitments and emission reduction targets. The Act expands upon the PSC’s CES mandate by requiring that at least 70% of the electricity in the state come from renewable energy technologies by 2030 and that the state's electric sector be 100% carbon free by 2040. See below for further information.

Clean Energy Standard

In 2016, the PSC adopted the state energy plan's goal that 50% of electricity be procured from renewable energy resources by 2030, as part of a strategy to reduce statewide greenhouse gas emissions 40% from 1990 levels by 2030.

The PSC also adopted a CES that includes renewable energy credit, or REC, and zero-emissions credit, or ZEC, requirements. Eligible renewable resources include wind, solar, hydroelectric, biomass, biogas, liquid biofuels, fuel cells and tidal ocean. Beginning in 2017, LSEs for their full-service customers are to obtain RECs and ZECs in amounts determined by the PSC. The LSEs subject to the CES include the state's electric distribution utilities, as well as all energy service companies, municipalities, cooperatives, the Long Island Power Authority and the New York Power Authority.

All eligible resources that came into operation after Jan. 1, 2015, are classified as Tier 1 resources. Under the CES, new renewable power resources were required to comprise 0.6% of the state’s total electricity load in 2017, and increasing to 4.8% in 2021. Tier 2 serves as a maintenance program to support existing renewable resources. Eligibility for the new Tier 2 is limited to: run-of-river hydroelectric facilities of 5 MW or less; wind facilities; and, biomass direct combustion facilities that were in commercial operation any time prior to Jan. 1, 2003, and were originally included in New York's baseline of renewable resources calculated when the states' renewable portfolio program was first adopted.

The overall renewables mandate, which includes both existing and new renewable generation increases from 26.32% in 2017 to 30.54% in 2021. The standards after 2021 are to be determined by the PSC every three years.

The obligations to achieve the CES are to be applied statewide. The LSEs will be permitted to meet their obligations by purchasing RECs from the New York State Energy Research and Development Authority, or NYSERDA, by purchasing qualified RECs from other sources or by making alternative compliance payments to NYSERDA.

The CES contains a Tier 3 that allows for the utilization of ZECs to preserve zero-emission attributes called for in the CES.

According to the PSC, maintaining zero-emission nuclear power is a critical element to achieving New York's ambitious climate goals. Adoption of the ZEC framework is designed to allow financially struggling upstate nuclear power plants to remain in operation during the state's transition to 50% renewables by 2030.

The CES framework provided for nuclear facilities deemed by the PSC to "demonstrate public necessity" and to be at risk of closure to be offered multiyear contracts with a state agency for the purchase of ZECs for each megawatt-hour of energy produced by an eligible plant. Specifically, the commission ordered that 12-year contracts with the nuclear facilities be administered in six two-year tranches. ZEC prices are based on a formula that takes into account the social cost of carbon, the impact from the state's participation in the Regional Greenhouse Gas Initiative, the forecast energy price and the forecast capacity price in the relevant market within the NYISO. LSEs, are required to purchase ZECs in proportion to load served and pass the costs to ratepayers through a commodity charge. The PSC determined that the James A. FitzPatrick, R.E. Ginna/Ontario Sta. 13 and Nine Mile Point nuclear plants met the criteria but Indian Point did not qualify.

Climate Leadership and Community Protection Act

On July 18, 2019, the CLCPA was signed into law, establishing a framework for reducing greenhouse gas emissions, increasing renewable electric generation and increasing energy efficiency. In addition, the law contains other socially responsible environmental, social and governance-type provisions geared toward "disadvantaged communities."

The law requires the PSC to establish a renewable energy program by June 30, 2021, that requires a minimum of 70% of statewide electric generation from the state's load-serving entities be generated by renewable energy systems by 2030. In addition, the law mandates that by 2040, emissions from the electric sector be eliminated.

The CLCPA specifies a new statewide greenhouse gas emissions reduction goal from all anthropogenic sources of 40% below 1990 levels by 2030 and 85% below 1990 levels by 2050, with the remaining 15% to be offset through "greenhouse gas emission offset projects" to achieve net-zero emissions in all sectors of the economy (see the Emissions requirements section).

The CLCPA codified various state procurement targets and called for the PSC to establish programs that require the state's load-serving entities to meet the targets. These targets include: at least 6 GW of photovoltaic solar generation by 2025; at least 3 GW of statewide energy storage capacity by 2030; and at least 9 GW of offshore wind by 2035. In addition, the Act codified the state’s targets for energy efficiency that calls for end-use energy savings of 185 trillion BTUs below 2025 energy-use forecast.

By July 1, 2024, and every two years thereafter, the PSC is to issue a comprehensive review of the renewable energy and zero emissions targets. The PSC may suspend or modify the obligations under the program if, after conducting a hearing, it makes a determination that the program "impedes the provision of safe and adequate electric service," "is likely to impair existing obligations and agreements" and/or there is a significant increase in arrears or service disconnections related to the program.

The PSC, to the extent practicable, is to specify a minimum percentage of energy storage projects that should be delivered into New York ISO zones that serve disadvantaged communities. In addition, the PSC is to facilitate the deployment of energy storage projects for the reduction of combustion-powered peaking facilities located in or near disadvantaged communities.

The CLCPA establishes a 22-member climate action council tasked with preparing a scoping plan that identifies and makes recommendations on how the state can attain the goal of achieving 100% net-zero greenhouse gas emissions in all sectors of the economy by 2050 (see the Emissions requirements section).

ESG-type social equity initiatives under the Climate Leadership and Community Protection Act

The CLCPA provides funding toward ESG-type social equity initiatives requiring that at least 35% of the state's clean energy benefits go to disadvantaged communities.

According to the law, "climate change especially heightens the vulnerability of disadvantaged communities, which bear environmental and socioeconomic burdens as well as legacies of racial and ethnic discrimination. Actions undertaken by New York state to mitigate greenhouse gas emissions should prioritize the safety and health of disadvantaged communities, control potential regressive impacts of future climate change mitigation and adaptation policies on these communities, and prioritize the allocation of public investments in these areas."

The law states that "ensuring career opportunities are created and shared geographically and demographically is necessary to ensure increased access to good jobs for marginalized communities while making the same neighborhoods more resilient. Climate change has a disproportionate impact on low-income people, women, and workers. It is in the interest of the state of New York to protect and promote the interests of these groups against the impacts of climate change and severe weather events and to advance our equity goals by ensuring quality employment opportunities in safe working environments." (Section updated 2/26/20)

Emissions Requirements

State-level greenhouse gas emission reduction goals

The Climate Leadership and Community Protection Act, or CLCPA , which was enacted on July 18, 2019, specifies a new statewide greenhouse gas emissions reduction goal from all anthropogenic sources of 40% below 1990 levels by 2030 and 85% below 1990 levels by 2050, with the remaining 15% to be offset through "greenhouse gas emission offset projects" to achieve net-zero emissions in all sectors of the economy.

The CLCPA defines statewide greenhouse gas emissions to mean "carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and any other substance emitted into the air that may be reasonably anticipated to cause or contribute to anthropogenic climate change."

In addition, the CLCPA defines statewide greenhouse gas emissions as "the total annual emissions of greenhouse gases produced within the state from anthropogenic sources and greenhouse gases produced outside of the state that are associated with the generation of electricity imported into the state and the extraction and transmission of fossil fuels imported into the state."

By Jan. 1, 2021, the state Department of Environmental Conservation, or DEC, is to consider establishing a mandatory registry and reporting system.

By Jan. 1, 2022, and each year thereafter, the DEC is to issue a report on statewide greenhouse gas emissions from all greenhouse gas emissions sources. The report is to include "an estimate of greenhouse gas emissions associated with the generation of imported electricity and with the extraction and transmission of fossil fuels imported into the state which shall be counted as part of the statewide total."

In addition, by Jan. 1, 2024, the DEC is to promulgate rules and regulations to ensure compliance with the statewide emissions reduction limits. The regulations are to include "measures to reduce emissions from greenhouse gas emission sources that have a cumulatively significant impact on statewide greenhouse gas emissions, such as internal combustion vehicles that burn gasoline or diesel fuel and boilers or furnaces that burn oil or natural gas."

In order to comply with the statewide greenhouse gas emissions limits, an alternative compliance mechanism, or ACM, may be utilized by entities subject to greenhouse gas emissions limits to achieve net-zero emissions. The electric generation sector is not eligible to participate in an ACM. The law specifies that such mechanisms may not account for more than 15% of statewide greenhouse gas emissions and the "use of this mechanism must offset a quantity greater than or equal to the greenhouse gases emitted." In addition, the offset of greenhouse gas emissions is not to "result in disadvantaged communities having to bear a disproportionate burden of environmental impacts."

The CLCPA calls for the DEC to establish an application process for alternative compliance that, at a minimum, would require that the entities "sufficiently demonstrate" that compliance with the greenhouse gas emissions limits is not "technologically feasible" and that the entities have "reduced emissions to the maximum extent practicable." After an initial four-year period, the DEC would be required to review whether the entities may continue participation in the ACM.

The CLCPA establishes a 22-member climate action council tasked with preparing a scoping plan that identifies and makes recommendations on how the state can attain the goal of achieving 100% net-zero greenhouse gas emissions in all sectors of the economy by 2050. A draft scoping plan is to be submitted by Jan. 1, 2022, and a final scoping plan is to be completed by Jan. 1, 2023, with updates every five years. The scoping plan is to contain several recommendations as noted in the accompanying chart, including measures to minimize "leakage," defined as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside of the state." The scoping plan is to be incorporated into the state's energy plan.

As part of the council, several working groups are to be formed. A "just transition working group" is to advise the council on "issues and opportunities for workforce development and training related to energy efficiency measures, renewable energy and other clean energy technologies, with specific focus on training and workforce opportunities for disadvantaged communities, and segments of the population that may be underrepresented in the clean energy workforce such as veterans, women and formerly incarcerated persons." The working group is to identify energy-intensive industries and related trades and identify sector-specific impacts of the state's current workforce and avenues to maximize the skills and expertise of New York state workers in the new energy economy." In addition, the working group is to "identify sites of electric generating facilities that may be closed as a result of a transition to a clean energy sector and the issues and opportunities presented by reuse of those sites." The group is also to advise the council on "the potential impacts of carbon leakage risk on New York state industries and local host communities, including the impact of any potential carbon reduction measures on the competitiveness of New York state business and industry."

A climate justice working group is to be created by July 1, 2020, to establish criteria to identify disadvantaged communities based on geographic, public health, environmental hazard and socioeconomic criteria.

New York City-level greenhouse gas emission reduction goals

In May 2019, legislation, known as the Climate Mobilization Act was enacted requiring large buildings, both commercial and residential, in New York City to reduce greenhouse gas emissions by 40% by 2030 and 80% by 2050, relative to 2005 levels. To meet the carbon reduction mandates, building owners may achieve compliance through operational changes, retrofits, purchasing greenhouse gas offsets, purchasing renewable energy credits, utilizing clean distributed energy resources.

Regional initiatives

New York is part of the Regional Greenhouse Gas Initiative, or RGGI, a cooperative effort among several Northeastern and Mid-Atlantic states to reduce greenhouse gas and power-related emissions. The RGGI member states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

Clean Power Plan

In 2015, the U.S. Environmental Protection Agency, or EPA, released the final version of its Clean Power Plan, or CPP. The CPP calls for a 32% reduction nationwide in the domestic power sector's carbon dioxide emissions by 2030, versus 2005 levels.

In 2016, the U.S. Supreme Court stayed the rule, pending the outcome of a review by the U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. The stay prevented the CPP from becoming effective until the D.C. Circuit issues a ruling on the merits and the Supreme Court takes action on any subsequent appeals from that ruling.

In 2017, President Donald Trump issued an executive order that effectively initiated the process of reversing the steps that had been taken to date on the CPP. In October 2017 the EPA Administrator began the formal process of reversing the Clean Power Plan.

On June 19, 2019, the EPA released its final Affordable Clean Energy, or ACE, rule, which replaces the CPP. The ACE rule focuses on CO_2 emissions and efficiency improvements at existing coal-fired power plants. According to the EPA, the regulation would cut about 11 million short tons of CO_2 from existing coal-fired generators by 2030. After the guidelines are finalized, states will have three years to develop and submit compliance plans that include site-specific measures based on a coal unit's potential for efficiency gains. However, opposition to the plan is already taking shape. (Section updated 2/26/20)

Reliability Issues

The PSC is permitted to address utility underperformance in terms of service restoration following storms, and is authorized to levy penalties based on company revenues. The utilities are required to file detailed emergency preparedness plans annually, and the commission has the authority to revoke a utility's operating license if necessary.

The PSC has adopted a Reliability Performance Mechanism, or RPM, for each major electric utility in the state. The RPM establishes a minimum reliability performance level, with earnings consequences if this level is not achieved. Each RPM includes threshold standards for the System Average Interruption Frequency Index and Customer Average Interruption Duration Index. These indices are calculated on an annual basis and exclude outages caused by major storms, catastrophic events, and incidents beyond the utility's control. The frequency and duration threshold standards are set by the PSC during a utility's rate case proceeding. There are also utility-specific RPM metrics in areas where a utility has repeatedly failed to complete work under its own initiative. The maximum penalty ranges between $2 million and $112 million. These penalty levels are based on company revenues and historical reliability performances.

The PSC has also adopted Electric Safety Standards related to stray voltage, as well as the reliability of the electric system. The standards include: (1) annual stray voltage testing of electric facilities accessible to the public; (2) inspection of utility electric facilities on a minimum of a five-year cycle; (3) recordkeeping, certification, quality assurance and reporting requirements; and, (4) adoption of the National Electric Safety Code as the minimum standard governing utility construction, maintenance and operations. The standards have annual performance targets with predetermined revenue adjustments if the targets are not met. Failure to achieve any of the annual performance targets will result in a revenue adjustment equal to 75 ROE basis points.

On Feb. 16, 2017, the PSC adopted a $153.3 million settlement for Consolidated Edison Co. of New York Inc., or CECONY, stemming from an investigation into the East Harlem gas explosion that occurred in 2014. Under the approved settlement, in lieu of potential remedies that could have been sought by the PSC in a civil penalty or prudence proceeding, CECONY is to forgo recovery of $128.3 million of costs largely incurred in 2014, 2015 and 2016 related to leak response-related activities, gas safety public education programs, emergency payments to residents and businesses immediately following the explosion, and expenses related to remediating leak-prone gas pipes. In addition, the company agrees to earmark $25 million for the benefit of customers. (Section updated 5/4/17)

Rate Structure

In 2013, a new minimum threshold for mandatory hourly pricing, or MHP, was implemented for Niagara Mohawk Power, or NMP, reducing the threshold from 500 KW to 250 KW. This reduction made NMP's MHP threshold the lowest in the state. New York's five other major investor-owned electric utilities have MHP thresholds that range from 300 KW to 500 KW. Customers on MHP rates are billed for supply based on individual hourly prices, which allows them to shift their usage from high price, high usage hours to lower price hours and reduce their supply costs. Reducing load during high price, high usage hours also lowers the wholesale market price by reducing the peak demand. (Section updated 11/21/16)

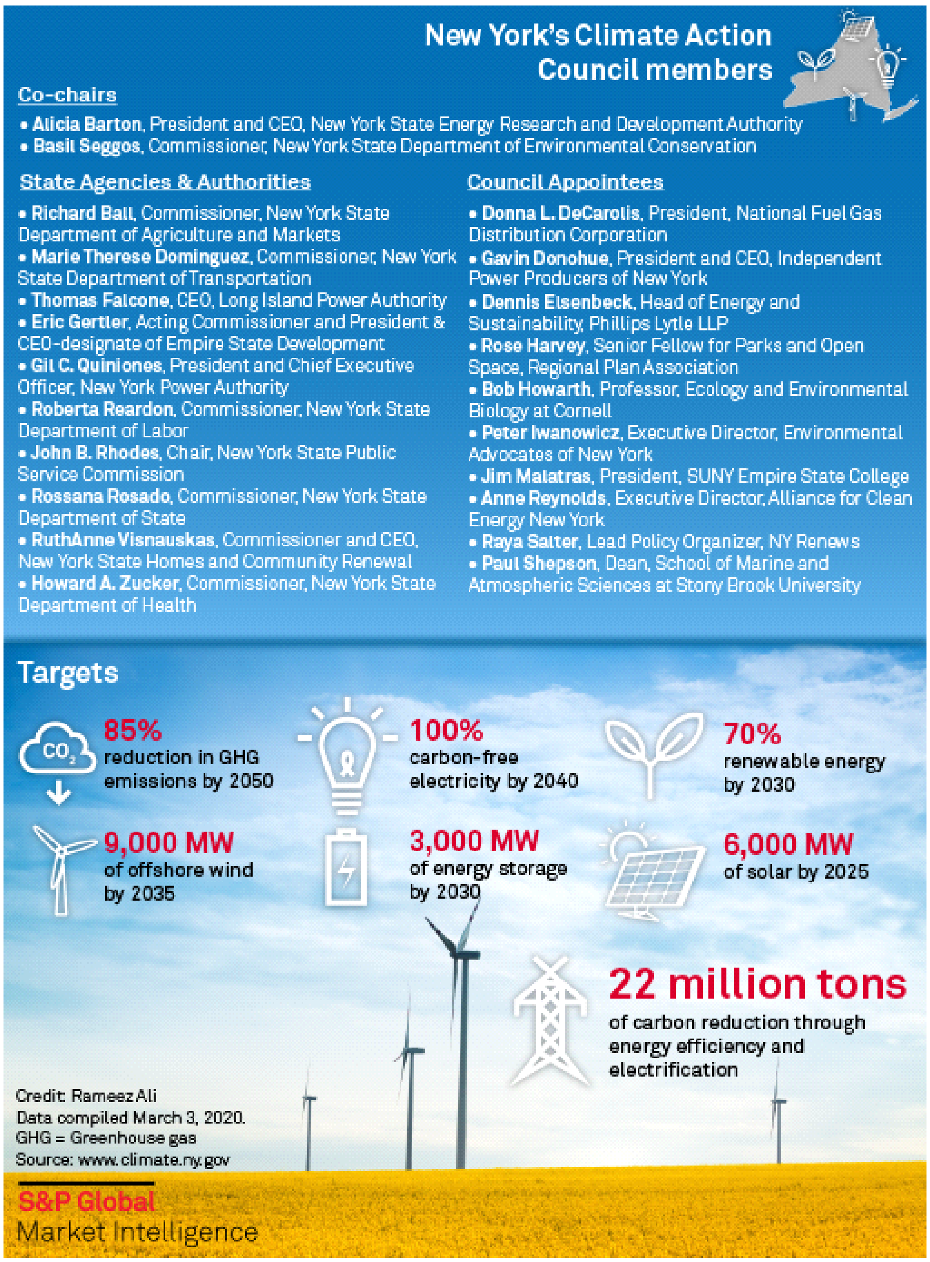
RRA REGULATORY FOCUS

Climate Action Council holds first meeting to kick off NY's green mandates

Friday, March 13, 2020 11:39 AM ET

By Lisa Fontanella
Market Intelligence

The New York Climate Action Council, tasked with developing a scoping plan to advance New York's efforts to achieve 100% net-zero greenhouse gas emissions in all sectors of the economy by 2050, held its first meeting on March 3.



The 22-person council was created as part of the July 2019 enactment of the New York State Climate Leadership and Community Protection Act, or CLCPA, which establishes a framework for reducing greenhouse gas emissions, increasing renewable electric generation and increasing energy efficiency. In addition, the CLCPA contains other socially responsible environmental, social and governance-type provisions geared toward "disadvantaged communities."

The council is co-chaired by Alicia Barton, President and CEO of the New York State Energy Research and Development Authority, or NYSERDA, and Basil Seggos, Commissioner of the New York State Department of Environmental Conservation, or DEC. The climate action council is to submit a draft scoping plan by Jan. 1, 2022, and a final scoping plan is to be completed by Jan. 1, 2023, with updates every five years.

Background of the CLCPA

Under the CLCPA, the New York Public Service Commission is to establish a renewable energy program by June 30, 2021, that requires a minimum of 70% of statewide electric generation from the state's load-serving entities be generated by renewable energy systems by 2030. In addition, the CLCPA mandates that by 2040, emissions from the electric sector be eliminated.

Under the CLCPA, the PSC is to establish programs that require the state's load-serving entities to meet the following procurement targets: at least 6 GW of photovoltaic solar generation by 2025; at least 3 GW of statewide energy storage capacity by 2030; and at least 9 GW of offshore wind by 2035.

By July 1, 2024, and every two years thereafter, the PSC is to issue a comprehensive review of the renewable energy and zero emissions targets. The PSC may suspend or modify the obligations under the program if, after conducting a hearing, it makes a determination that the program "impedes the provision of safe and adequate electric service," "is likely to impair existing obligations and agreements" and/or there is a significant increase in arrears or service disconnections related to the program.

The PSC, to the extent practicable, is to specify a minimum percentage of energy storage projects that should be delivered into New York ISO zones that serve disadvantaged communities. In addition, the PSC is to facilitate the deployment of energy storage projects for the reduction of combustion-powered peaking facilities located in or near disadvantaged communities.

The CLCPA outlines a new statewide greenhouse gas emissions reduction goal from all anthropogenic sources of 40% below 1990 levels by 2030 and 85% below 1990 levels by 2050, with the remaining 15% to be offset through "greenhouse gas emission offset projects" to achieve net-zero emissions in all sectors of the economy.

In addition, by Jan. 1, 2024, the DEC is to promulgate rules and regulations to ensure compliance with the statewide emissions reduction limits. The regulations are to include "measures to reduce emissions from greenhouse gas emission sources that have a cumulatively significant impact on statewide greenhouse gas emissions, such as internal combustion vehicles that burn gasoline or diesel fuel and boilers or furnaces that burn oil or natural gas."

By Jan. 1, 2022, and each year thereafter, the DEC is to issue a report on statewide greenhouse gas emissions from all greenhouse gas emissions sources. The report is to include "an estimate of greenhouse gas emissions associated with the generation of imported electricity and with the extraction and transmission of fossil fuels imported into the state which shall be counted as part of the statewide total." By Jan. 1, 2021, the DEC is to consider establishing a mandatory registry and reporting system.

The DEC is to convene a climate justice working group by July 1, 2020, to establish criteria to identify disadvantaged communities based on geographic, public health, environmental hazard and socioeconomic criteria.

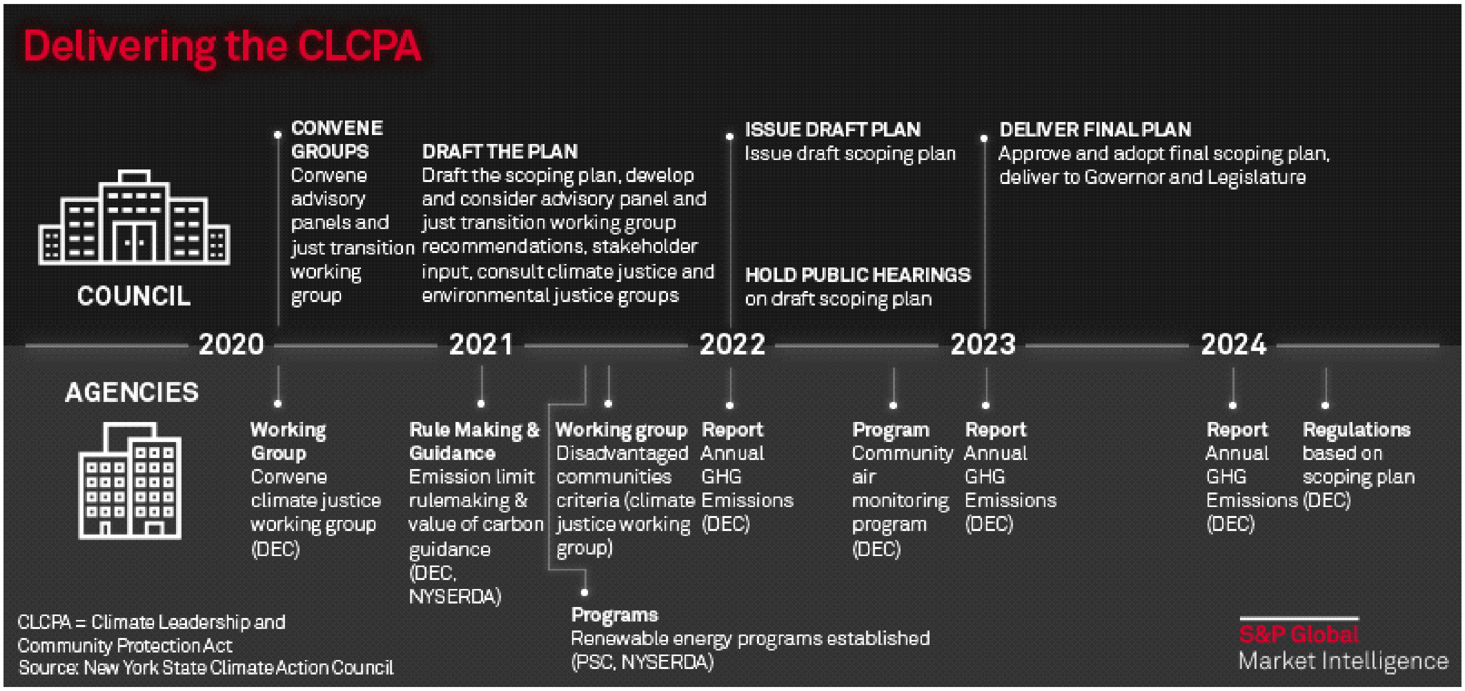
The CLCPA establishes an energy efficiency goal of 185 trillion Btu of end-use energy savings below the 2025 end-use forecast. The PSC is to include mechanisms to ensure that, where practicable, at least 20% of investments must be earmarked for residential energy efficiency, including multifamily housing, and be utilized to benefit disadvantaged communities including low-to-moderate income communities.

Climate Action Council

The 22-member climate action council is co-chaired by the heads of NYSERDA and the DEC and is made up of various heads of different state agencies, including the PSC, as well as experts appointed by Gov. Andrew Cuomo.

The council is to prepare a scoping plan containing recommendations to achieve the statewide greenhouse gas emissions reduction goals of 40% below 1990 levels by 2030, 85% below 1990 levels by 2050 and 100% net-zero greenhouse gas emissions in all sectors of the economy by 2050.

A draft scoping plan is to be submitted by Jan. 1, 2022, and a final scoping plan is to be completed by Jan. 1, 2023, with updates every five years.



The scoping plan is to contain several recommendations as noted in the accompanying chart, including measures to minimize "leakage," defined as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside of the state." The scoping plan is to be incorporated into the state's energy plan.

Scoping plan

The scoping plan is to contain recommendations related to:

Measures and actions in performance-based standards for sources of greenhouse gas emissions, including transportation, building, industrial, commercial and agricultural sectors.
Measures to reduce emissions from the electricity sector by displacing fossil fuel-fired electricity with renewable electricity or energy efficiency.
Land-use and transportation planning measures aimed at reducing greenhouse gas emissions from motor vehicles.
Measures to achieve long-term carbon sequestration and/or promote best management practices in land use, agriculture and forestry.
Measures to achieve the 6 GW of distributed solar energy capacity, 9 GW of offshore wind capacity, statewide energy efficiency goal of 185 trillion Btu energy reduction from the 2025 forecast and 3 GW of statewide energy storage capacity.
Measures to promote the beneficial electrification of personal and freight transport and other strategies to reduce greenhouse gas emissions from the transportation sector.
Measures to achieve reductions in energy use in existing residential or commercial buildings.
Recommendations to aid in the transition of the state workforce and the rapidly emerging clean energy industry.
Measures to achieve healthy forests that support clean air and water and biodiversity and that sequester carbon.
Measures to limit the use of chemicals, substances or products that contribute to global climate change when released to the atmosphere but are not intended for end-use combustion.
Mechanisms to limit emission leakage.

As of July 26, 2019.
Source: New York State Climate Leadership and Community Protection Act

As part of the council, a "just transition working group" is to be formed. A "just transition working group" is to advise the council on "issues and opportunities for workforce development and training related to energy efficiency measures, renewable energy and other clean energy technologies, with specific focus on training and workforce opportunities for disadvantaged communities, and segments of the population that may be underrepresented in the clean energy workforce such as veterans, women and formerly incarcerated persons." The working group is to identify energy-intensive industries and related trades and identify sector-specific impacts of the state's current workforce and avenues to maximize the skills and expertise of New York state workers in the new energy economy." In addition, the working group is to "identify sites of electric generating facilities that may be closed as a result of a transition to a clean energy sector and the issues and opportunities presented by reuse of those sites." The group is also to advise the council on "the potential impacts of carbon leakage risk on New York state industries and local host communities, including the impact of any potential carbon reduction measures on the competitiveness of New York state business and industry."

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the S&P Global Market Intelligence Energy Research Library.

Rameez Ali contributed to this article.

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Edison Electric Institute

Alternative Regulation for Emerging Utility Challenges: 2015 Update

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November 11, 2015

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Contents

I. Introduction

Investor-owned electric utilities in the United States are buffeted today by varied and rapid changes in the business conditions they face. For vertically integrated electric utilities ("VIEUs") and utility distribution companies ("UDCs") alike, the traditional cost of service approach to rate regulation is often not ideal for helping utilities cope with these changes. Alternative approaches to regulation ("Altreg") can often help utilities secure better outcomes for their customers and shareholders.

The changing business climate stems primarily from three root causes. One is pressure, from policymakers and many customers, for the power industry to lighten its environmental footprint. In addition to evolving renewable portfolio standards at the state level, utilities must comply with an array of federal initiatives such as the Environmental Protection Agency's Clean Power Plan. Demand-side management ("DSM") programs and tightening building codes and appliance standards encourage energy efficiency. Some customers seek power from greener sources than the increasingly clean portfolios of utilities. Self generation from rooftop solar is one means to this end, and its cost is falling. Customer-sited distributed generation ("DG") must be accommodated, and utilities must purchase power surpluses that these facilities generate at regulated rates.

A second force for change is technological progress in metering and distribution. Advanced metering infrastructure and other smart grid technologies can improve reliability and facilitate integration of intermittent renewables. Time-sensitive pricing can encourage customers to use the grid in less costly ways. New value-added optional products and services can be offered which benefit customers.

A third force for change is increased concern about the reliability and resiliency of grid service. Some facilities are approaching advanced age, and some need more protection from severe weather. Many customers seek better quality service.

These forces are having important practical effects on utilities. Growth in the demand for their traditional services has slowed, and utilities face competition from distributed energy resources ("DERs"). Nevertheless, some utilities need capital expenditures ("capex") for cleaner generating capacity, smart grid facilities, increased resiliency, and replacement of aging assets. Many new facilities don't automatically trigger revenue growth. Increased marketing flexibility is needed to meet competitive challenges and complex, changing customer needs.

Under traditional regulation, the base rates that compensate utilities for costs of non-energy inputs are reset only in general rate cases with historical test years. These lengthy proceedings require a detailed review of all costs and their allocation amongst the utility's retail services. Revenue from secondary sources (e.g., off-system sales) is imputed against the revenue requirement.

Most base rate revenue is drawn from volumetric and other usage charges. Since the cost of base rate inputs is driven more by capacity than system use in the short run, a utility's finances are sensitive between rate cases to the gap between growth in system use and capacity. A convenient proxy for this gap is the growth in use per customer (aka "average use"). The need for rate cases increases when average use declines.

Traditional regulation is ill-suited for addressing many of today's challenges. Growth in average use was once positive, and the resulting incremental revenues helped utilities finance rising cost without rate cases. Today, growth in the average use of residential and commercial customers is typically static and often negative. Utilities needing normal or high capital expenditures are then compelled to file rate cases more frequently. These involve high regulatory cost and are nonetheless frequently uncompensatory when they involve historical test years. Frequent rate cases also reduce utility opportunities to increase earnings from improved cost containment and marketing. Traditional regulation also does not allow for many value-added or optional rates and services. Improved utility performance is thus discouraged at a time when it is increasingly needed to respond to competitive pressures.

Increased financial attrition has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

Alternative approaches to regulation have been developed which handle today's business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, can involve sweeping regulatory change. Others, like revenue decoupling and cost trackers, target specific challenges.

This survey, now updated to include precedents through mid-2015, explains Altreg options and details precedents in the regulation of retail electric utility rates. A summary of states that currently use these approaches is featured in Table 1. Information is also provided on precedents for gas and water distributors and for energy utilities in Australia, Canada, and Britain. This year's survey also discusses marketing flexibility, a new Altreg area of growing interest to EEI members.

Figure 1

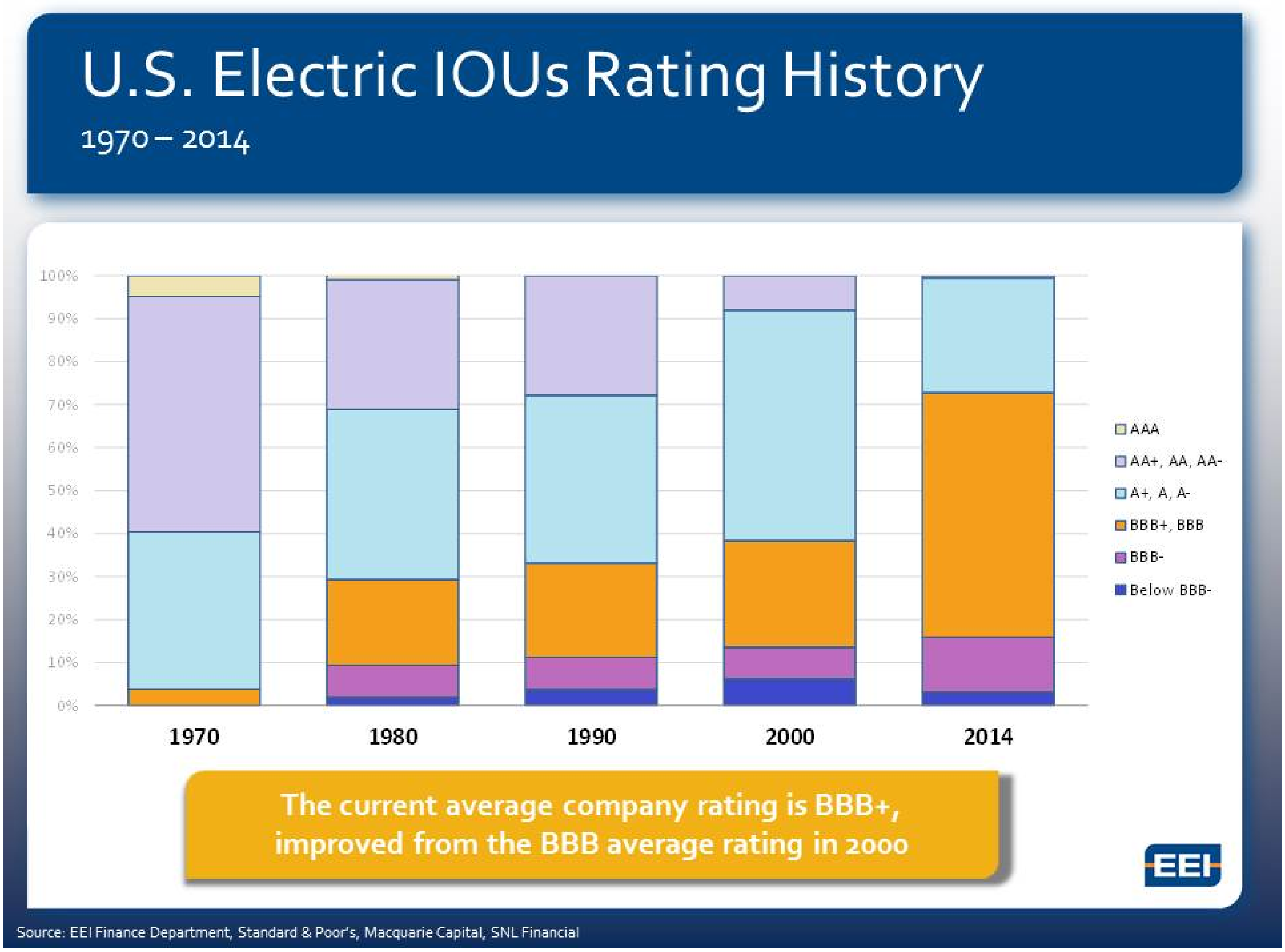

U.S. Electric IOUs Rating History
1970 – 2014
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1970
1980
1990
2000
2014
AAA
AA+, AA, AA-
A+, A, A-
BBB+, BBB
BBB-
Below BBB-
The current average company rating is BBB+, improved from the BBB average rating in 2000
EEI
Source: EEI Finance Department, Standard & Poor's, Macquarie Capital, SNL Financial

Table 1

Alternative Regulation Tools: An Overview of Current Precedents

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans[1]	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Alabama	Electric & Gas					Electric & Gas	Yes
Alaska							
Arizona	Electric, Gas, & Water	Gas only	Electric & Gas		Electric only		
Arkansas	Electric & Gas	Gas only	Electric & Gas				
California	Electric & Gas	Electric & Gas			Electric & Gas		Yes
Colorado	Electric & Gas				Electric only		
Connecticut	Electric, Gas, & Water	Electric & Gas	Gas only	Electric & Gas			Yes
Delaware	Electric, Gas, & Water						
District of Columbia	Electric & Gas	Electric only					
Florida	Electric & Gas			Gas only	Electric only		Yes
Georgia	Electric & Gas	Gas only		Gas only	Electric only	Gas only	Yes
Hawaii	Electric only	Electric only			Electric only		Yes
Idaho	Electric only	Electric only					
Illinois	Gas & Water	Gas only		Electric & Gas		Electric only	Yes
Indiana	Electric, Gas, & Water	Gas only	Electric only		Gas only		
Iowa	Gas only			Gas only	Electric only		
Kansas	Gas only		Electric only	Gas only			
Kentucky	Electric & Gas		Electric & Gas	Gas only			Yes
Louisiana	Electric only		Electric only		Electric only	Electric & Gas	Yes
Maine	Electric, Gas, & Water	Electric only		Gas only	Gas only		Yes
Maryland	Electric & Gas	Electric & Gas					
Massachusetts	Electric & Gas	Electric & Gas	Electric & Gas		Gas only		
Michigan	Gas only	Gas only					Yes

Table 1 continued

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans[1]	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Minnesota	Electric & Gas	Electric & Gas					Yes
Mississippi	Electric & Gas		Electric & Gas	Electric only		Electric & Gas	Yes
Missouri	Gas & Water			Gas only			
Montana	Electric & Gas		Gas only				
Nebraska	Gas only			Gas only			
Nevada	Gas only	Gas only	Electric only				
New Hampshire	Electric, Gas, & Water			Gas only	Electric & Gas		
New Jersey	Electric, Gas, & Water	Gas only					
New Mexico							Yes
New York	Gas & Water	Electric & Gas	Gas only	Electric & Gas	Electric & Gas		Yes
North Carolina	Gas & Water	Gas only	Electric only				
North Dakota	Electric only			Gas only	Electric only		Yes
Ohio	Electric, Gas, & Water	Electric only	Electric only	Gas only	Electric only		
Oklahoma	Electric only		Electric only	Electric & Gas		Gas only	
Oregon	Electric & Gas	Electric & Gas	Electric & Gas				Yes
Pennsylvania	Electric, Gas, & Water			Gas only			Yes
Rhode Island	Electric & Gas	Electric & Gas					Yes
South Carolina	Electric only		Electric only			Gas only	
South Dakota	Electric only						
Tennessee	Gas only	Gas only		Gas only		Gas only	Yes
Texas	Electric & Gas			Gas only		Gas only	
Utah	Gas only	Gas only					Yes
Vermont				Gas only			
Virginia	Electric & Gas	Gas only		Gas only	Electric only		
Washington	Gas only	Electric & Gas			Electric & Gas		
West Virginia	Electric only						
Wisconsin				Gas only			Yes
Wyoming	Electric only	Gas only	Electric & Gas	Electric & Gas			Yes

[1] This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

II. Cost Trackers

A cost tracker is a mechanism for expedited recovery of specific utility cost (e.g., outside of a rate case). Balancing accounts are typically used to track unrecovered costs. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are more practical than rate cases for addressing particular costs. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent rate cases and materially impact utility risk. Other volatile expenses that are sometimes addressed with trackers include those for pensions, severe storms, and uncollectible bills.

A second use of trackers is for costs incurred due to policies of government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agencies to consider the impact of their policies on customer bills.

Trackers are also used to compensate utilities for costs that are rapidly rising and don't otherwise trigger new revenue, whether or not they are volatile or mandated. This encourages needed expenditures and reduces risk and the frequency of rate cases. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in large measure to their rapid growth include those for health care.

Trackers for some costs have multiple rationales. DSM expenses, for example, are often sizable and sometimes grow rapidly.[1] Utility DSM programs are often mandated. Additionally, DSM can slow growth in the average use of power and reduce the need for plant additions, important sources of earnings growth for utilities. Tracking DSM expenses helps to balance utility incentives to embrace DSM.

Capital cost trackers typically address the accumulating depreciation, return on asset value, and taxes that result from the capex.[2] Capital costs can qualify for tracker treatment on several grounds. Major plant additions are volatile. Capex might be necessitated by highway construction or changes in government safety, reliability, or environmental standards. Capex is sometimes large enough to cause brisk cost growth that would otherwise occasion frequent rate cases.

An early use of capital cost trackers in the electric utility industry was to address construction costs of large power plants. These plants can take years to construct. An allowance in rates for a return on funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery of the allowance strains utility cash flow, increases financing expenses, and induces more rate "shock" when the value of the plant and construction financing is finally added to the rate base.

[1] This survey only documents capital cost trackers. Trackers for DSM expenses are ubiquitous so that there is less need for documentation.

[2] Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Many commissions have addressed these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers have often been used in lieu of frequent rate cases to obtain CWIP recovery.

Capital costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for large generation units, and construction of specific assets usually takes less than a year. However, the capex can still be sizable and doesn't automatically trigger new revenue when completed. A tracker for accelerated modernization costs can help a company modernize its grid and improve its services without frequent rate cases.

Capital costs of generation emissions controls are often accorded tracker treatment. These controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities typically become used and useful each year over a series of years.

There are varied treatments of costs in approved capital trackers. Regulators often approve tracked capex budgets in advance, usually after considerable deliberation. Procedures for reviewing the need for generation plant additions are especially well established. Once a budget is set, the treatment of variances between actual and budgeted cost becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (e.g., 50-50) between the utility and its customers. Utilities are also permitted sometimes to share in the benefits of capex underspends. The prudence of tracked capex is often subject to a final review when the cost is added to rate base, a step that usually occurs in the next rate case.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are numerous and continue to grow. This is the most widely used Altreg tool in the United States. For electric utilities, trackers for emissions controls, generation capacity, advanced metering infrastructure, and general system modernization have been especially common in recent years. Trackers for gas distributors typically address the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges, are also common for accelerated modernization.

Figure 2: Recent Capital Cost Tracker Precedents by State: Energy Utilities

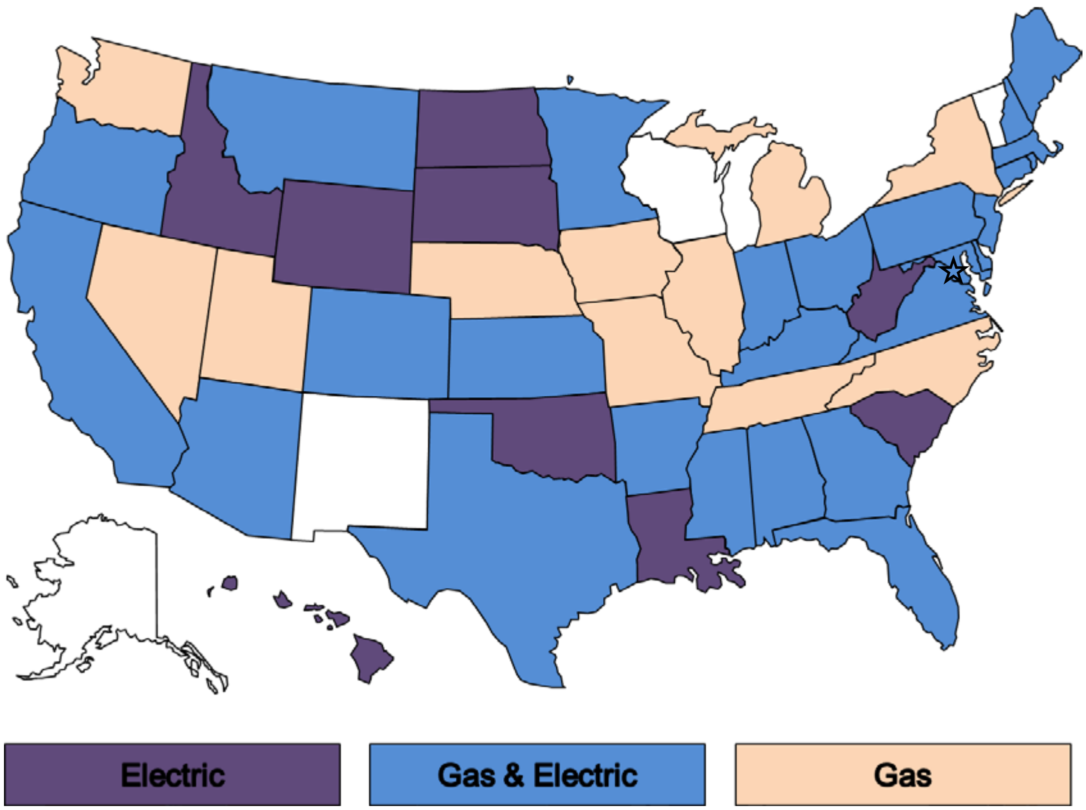


Figure 3: Recent Capital Cost Tracker Precedents by State: Water Utilities

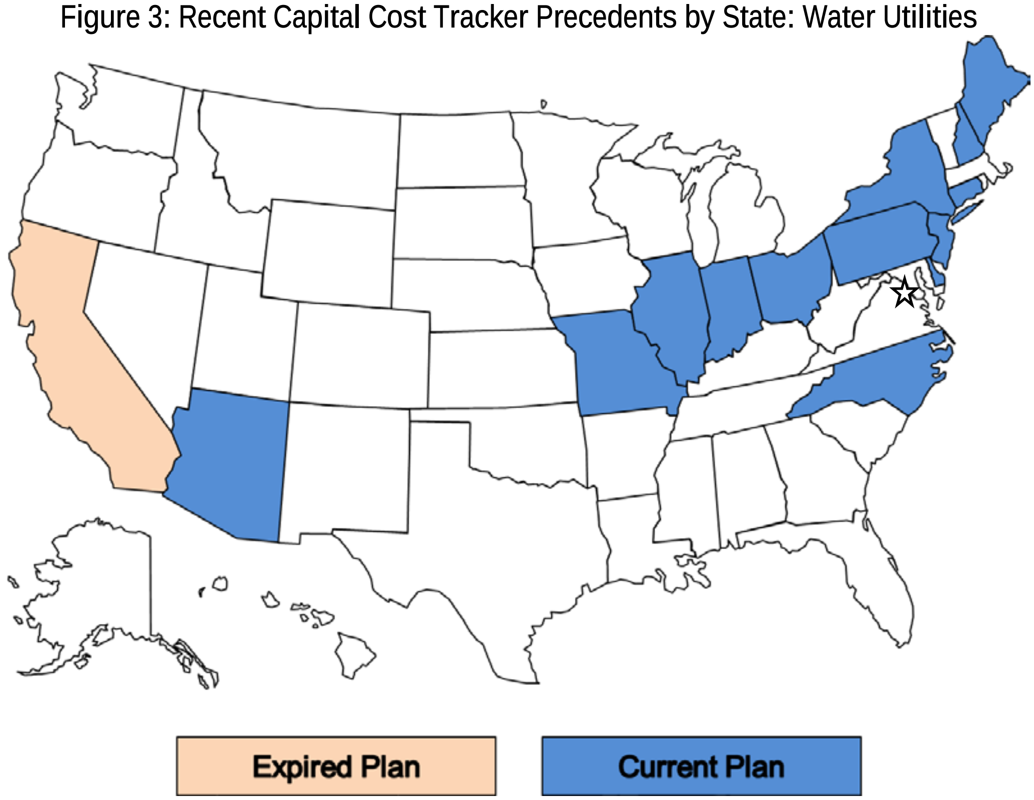


Table 2

Recent Capital Cost Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
AL	Alabama Power	Electric	Rate Certificated New Plant	Any approved by Commission through CPCN	Dockets 18117 and 18416 (November 1982)
AL	Mobile Gas Service	Gas	Cast Iron Replacement Factor	Replacement of cast iron mains	Docket 24794 (November 1995)
AR	Arkansas Oklahoma Gas	Gas	Act 310 Surcharge	Relocations of pipelines mandated by government agencies	Docket 12-088-U (July 2013)
AR	Arkansas Oklahoma Gas	Gas	System Safety Enhancement Rider	Replacement of bare steel mains, mains on low pressure systems, mains that are subject of an advisory notice by government that company deems to be unsatisfactory	Docket 13-078-U (July 2014)
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
AR	CenterPoint Energy Arkla	Gas	Government Mandated Expenditure Surcharge Rider	Replacements resulting from highway and street rebuilding	Docket 10-108-U (March 2011)
AR	Empire District Electric	Electric	Alternative Generation Environmental Recovery Rider	Environmental	Docket 15-010-U (August 2015)
AR	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Systemwide smart grid implementation	Docket 10-109-U (August 2011)
AR	SourceGas Arkansas	Gas	At-Risk Meter Relocation Program Rider	Installation of new services for meters relocated due to motor vehicle collision risk	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Main Replacement Program Rider	Replacement of bare steel and coated steel mains, mains that are subject of an advisory notice by government that company deems to be unsatisfactory, and associated services	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Act 310 Surcharge	Bare steel and cast iron pipeline replacement, in-line inspection project, emissions controlling catalysts for compressor station engines, greenhouse gas monitoring of some regulator stations, highway relocation projects	Docket 13-072-U (April 2014)
AR	SWEPCO	Electric	Alternative Generation Recovery Rider	New generation	Docket 09-008-U (November 2009)
AR	SWEPCO	Electric	Rider Environmental Compliance Surcharge	Environmental	Docket 15-021-U (October 2015)
AZ	Arizona Public Service	Electric	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates	Docket E-01345A-08-0172
AZ	Arizona Public Service	Electric	Environmental Improvement Surcharge	Environmental improvement projects	Docket E-01345A-11-0224 (May 2012)
AZ	Arizona Public Service	Electric	Four Corners Rate Rider Surcharge	Generation	Docket E-01345A-11-0224 (December 2014)
AZ	Arizona Water Company	Water	Arsenic Cost Recovery Mechanism	Investments to reduce arsenic in water supply	Various (operating regions have separate decisions approving ACRMs)
AZ	Arizona Water Company - Eastern Group	Water	System Improvement Benefits Mechanism	Replacement of leak prone mains and related services, meters, and hydrants, replace meters that do not have lead free brass, other replacements for mains, services, meters, and hydrants that are at the end of their useful life	Decision 73938 (June 2013)
AZ	Southwest Gas	Gas	Customer Owned Yard Line Cost Recovery Mechanism	Replacement and ownership of customer-owned yard lines that have been shown to be leaking	Docket G-01551A-10-0458 (January 2012)
AZ	Tucson Electric Power	Electric	Environmental Compliance Adjustor	Miscellaneous environmental projects	Decision 73912 (June 2013)
CA	Pacific Gas & Electric	Electric	Smart Grid Memorandum Account	Smart grid projects that received DOE matching funds	Decision 09-09-029 (September 2009)
CA	Pacific Gas & Electric	Gas Transmission	Pipeline Safety Implementation Plan	Pipeline replacement, automated valve installation, and upgrades to pipeline	Decision 12-12-030 (December 2012)
CA	Pacific Gas & Electric	Electric	Smart Grid Pilot Deployment Project Balancing Account	Pilot programs for smart grid line sensors, volt/VAR optimization, detection and location of distribution line outages and faulted circuits, and information technology investments to improve short term demand forecasting for power procurement	Decision 13-03-032 (March 2013)
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Electric	Energy Storage Balancing Account	Projects to store solar energy	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CA	Southern California Edison	Electric	SmartConnect Balancing Account	Advanced metering infrastructure project	Decision 08-09-039 (September 2008)
CA	Southern California Edison	Electric	Solar PV Balancing Account	Solar generation	Decision 09-06-049 (June 2009)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
CA	Southern California Gas	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CO	Black Hills Colorado Electric	Electric	Transmission Cost Adjustment Rider	Transmission projects	Docket 09-014E, Decision C09-0271 (March 2009)
CO	Black Hills Colorado Electric	Electric	Clean Air Clean Jobs Act Rider	Gas-fired generation	Docket 14AL-0393E, Decision C14-1504 (December 2014)
CO	Public Service Company of Colorado	Electric	Transmission Cost Adjustment	Transmission projects	Docket 07A-339E, Decision C07-1085 (December 2007)
CO	Public Service Company of Colorado	Gas	Pipeline Safety Integrity Adjustment	Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements	Docket 10-AL-963G (August 2011)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
CO	Public Service Company of Colorado	Electric	Clean Air Clean Jobs Act Rider	Miscellaneous environmental projects including gas-fired generation, scrubbers	Proceeding 14A-680E, Decision C15-0292 (March 2015)
CO	Rocky Mountain Gas	Gas Transmission	System Safety and Integrity Rider	TIMP, DIMP, and other safety regulatory compliance projects	Docket 13AL-0046G, Decision R14-0114 (February 2014)
CT	Aquarion Water Company of Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-06-21WI01 (December 2008)
CT	Connecticut Light & Power	Electric	System Resiliency Plan	Structural hardening	Docket 12-07-06 (January 2013)
CT	Connecticut Natural Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Connecticut Natural Gas	Gas	DIMP True-Up Mechanism	Cast iron and bare steel main replacement	Docket 13-06-08; (January 2014)
CT	Connecticut Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-10-15WI01 (March 2009)
CT	Southern Connecticut Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Torrington Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17WI01 (December 2009)
CT	United Water Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17WI01 (December 2009)
CT	Yankee Gas Services	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
DC	Potomac Electric Power	Electric	Underground Project Charge	Undergrounding of specific feeders	Formal Case 1116 (November 2014)
DC	Washington Gas Light	Gas	Plant Recovery Adjustment	Remediation/replacement of mechanical couplings	Formal Case 1027 (December 2009)
DC	Washington Gas Light	Gas	Accelerated Pipe Replacement Plan Adjustment	Replacement of cast iron mains, bare steel mains and services and "black plastic" services	Formal Case 1115 (January 2015)
DE	Artesian Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-474 (December 2001)
DE	Delmarva Power & Light	Gas	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 12-546 (October 2013)
DE	Delmarva Power & Light	Electric	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 13-115 (August 2014)
DE	Sussex Shores Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-470 (December 2001)
DE	Tidewater Utilities	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 03-210 (May 2003)
DE	United Water Delaware	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-481 (December 2001)
FL	Chesapeake Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Florida City Gas	Gas	Safety and Access Verification Expedited Program	Replacement of unprotected steel mains, relocation of certain gas mains in rear lot easements	Docket 150116-GU (September 2015)
FL	Florida Power and Light	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 080281-EI (August 2008)
FL	Florida Power and Light	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Florida Power and Light	Electric	Generation Base Rate Adjustment	Generation	Docket 120015-EI (December 2012)
FL	Florida Public Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Gulf Power	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 930613-EI (January 1994)
FL	Peoples Gas System	Gas	Cast Iron/Bare Steel Replacement Rider	Replacement of bare steel and cast iron pipes	Docket 110320-GU (September 2012)
FL	Progress Energy Florida	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 050078-EI (September 2005)
FL	Progress Energy Florida	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Progress Energy Florida	Electric	Generation Base Rate Adjustment	Generation	Docket 130208 (November 2013)
FL	Tampa Electric	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 960688-EI (August 1996)
GA	Atlanta Gas Light	Gas	Pipeline Replacement Program Cost Recovery Rider	Replacement of cast iron and bare steel pipe	Docket 29950 as STRIDE tracker in 2009
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Surcharge	Pre-1985 plastic mains and services replacement, planned customer expansions, and infrastructure improvements that sustain reliability and operational flexibility	Docket 8516-U and 29950 (October 2009 and August 2013)
GA	Atmos Energy (now Liberty Utilities)	Gas	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket 12509-U (December 2000)
GA	Georgia Power Company	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Docket 25060-U (December 2007)
GA	Georgia Power Company	Electric	Nuclear Construction Cost Recovery	Nuclear generation	Docket 27800, Senate Bill 31
HI	Hawaii Electric Light	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Hawaiian Electric Company	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Maui Electric	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
IA	Black Hills Energy	Gas	System Safety Maintenance Adjustment	Replacement of steel and pvc pipe, relocations mandated by local governments	Docket RPU-2012-0004 (March 2013)
ID	PacifiCorp	Electric	Energy Cost Adjustment Mechanism	Lake Side II generation facility	Case PAC-E-13-04 (October 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
IL	Ameren Illinois	Gas	Rider Qualifying Infrastructure Plant	Replacement of prone to leak distribution and transmission pipe, installation of AMI and communications infrastructure, replacing or installing transmission or distribution facilities to establish over-pressure protection, replacement of difficult to locate mains and services, replacement of high pressure transmission pipelines without a recorded maximum allowable operating pressure, replacements to facilitate an upgrade from a low pressure system to a high pressure system	Docket 14-0573 (January 2015)
IL	Consumers Illinois Water Company (Kankakee, Vermilion, Woodhaven Districts)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-0561 (December 2001)
IL	Illinois-American Water (Chicago Metro Division)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 09-0251 (March 2010)
IL	Illinois-American Water (Single Tariff Pricing Zone)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 04-0336 (December 2004)
IL	Northern Illinois Gas	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast iron pipe, non-cast iron pipe, and copper services; relcoation of meters from inside customers' premises; upgrading of system from low pressure to medium pressure; replacement or installation of regulator stations, regulators, valves and associated facilities to establish over-pressure protection	Docket 14-0292 (July 2014)
IL	Peoples Gas Light & Coke	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast and ductile iron, relcoation of meters from inside customers' premises, upgrading of system from low pressure to medium pressure, replacement of high pressure transmission pipelines at higher risk of failure or lacking records, installation of regulator stations to establish over-pressure protection	Docket 13-0534 (January 2014)
IN	Duke Energy Indiana	Electric	Qualified Pollution Control Property	Miscellaneous environmental projects	Cause 41744 (February 2001)
IN	Duke Energy Indiana	Electric	Integrated Coal Gasification Combined Cycle Generating Facility Revenue Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket 43114 (November 2007)
IN	Indiana Michigan Power	Electric	Clean Coal Technology Rider	Miscellaneous environmental projects	Cause 43636 (June 2009)
IN	Indiana Water Service	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42743 DSIC-1 (December 2004)
IN	Indiana-American Water	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42351 DSIC-1 (February 2003)
IN	Indianapolis Power & Light	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Cause 42170 (November 2002)
IN	Northern Indiana Public Service	Electric	Environmental Cost Recovery Mechanism	Miscellaneous environmental projects	Cause 42150 (November 2002)
IN	Northern Indiana Public Service	Electric	Transmission, Distribution & Storage System Improvement Charge	Investments to maintain the capacity deliverability of system and replacement of aging infrastructure, economic development	Cause 44370 and 44371 (February 2014)
IN	Northern Indiana Public Service	Gas	Distribution System Improvement Charge	Gas system deliverability and system integrity projects, rural main extensions	Cause 44403 TDSIC 1 (January 2015)
IN	Utility Center Inc.	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 42416 DSIC-1 (June 2003)
IN	Vectren Energy Delivery (Indiana Gas and Southern Indiana Gas & Electric)	Gas	Compliance and System Improvement Adjustment	System and pressure improvements, storage operations, instrumentation and communications equipment, public improvement projects, service replacements, and economic development	Cause 44429 (August 2014)
KS	Atmos Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 08-AQLG-852-TAR (July 2008)
KS	Kansas Gas Service	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-KGSG-155-TAR (December 2009)
KS	Midwest Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 09-MDWE-722-TAR (May 2009)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocations	Docket 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 2009-00141 (September 2009)
KY	Delta Natural Gas	Gas	Pipe Replacement Program Surcharge	Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case 2010-00116 (October 2010)
KY	Kentucky Power	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Docket 2002-00169 (March 2003)
KY	Kentucky Utilities	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 93-465 (July 1994)
KY	Louisville Gas & Electric	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 94-332 (April 1995)
KY	Louisville Gas & Electric	Gas	Gas Line Tracker	Replacement and transfer of ownership of customer owned service risers	Case 2012-00222 (December 2012)
LA	Cleco Power	Electric	Infrastructure and Incremental Costs Recovery	Projects to be determined in subsequent filings to Commission	Docket U-30689 and U-32779 (October 2010 and June 2014)
LA	Entergy Gulf States Louisiana	Electric	Formula Rate Plan-3	Acquisition of generating facility, new generating facility or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million	Docket U-32707 (December 2013)
LA	Entergy Louisiana	Electric	Formula Rate Plan 7	Cost of Ninemile 6 natural gas generating facility; New generating facility, acquisition of a generating facility, or refurbishment of existing generating facility if the revenue requirement related to the project exceeds $10 million	Docket U-32708 and 31971 (January 2014 and April 2012)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	Bay State Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, service tie-ins, encroached pipe, and meters	DPU 14-134
MA	Berkshire Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron mains and associated services, encroached pipe, and meter sets composed of non-cathodically protected steel, cast iron or copper	DPU 14-131
MA	Fitchburg Gas & Electric Light	Gas	Gas System Enhancement Adjustment Factor	Replacement of cast main and unprotected steel mains and services and encroached pipe	DPU 14-130

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MA	Massachusetts Electric	Electric	Net CapEx Factor	Potentially all distribution investments	DPU 09-39
MA	Massachusetts Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Massachusetts Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	Nantucket Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Nantucket Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-132
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron	DPU 10-114
MA	New England Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-133
MA	NSTAR Electric	Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade	DTE 05-85 and DPU 10-70-B
MA	NSTAR Electric	Electric	Smart Grid Adjustment Factor	Smart grid pilot	DPU-09-33
MA	Western Massachusetts Electric	Electric	Solar Program Cost Adjustment	Solar generation	DPU 09-05
MD	Baltimore Gas & Electric	Electric	Electric Reliability Investment Surcharge	Upgrades to improve poorest performing feeders, selective undergrounding, expanded recloser development on 13kV and 34 kV lines, diverse routing of 34 kV supply circuits	Case 9326 (December 2013)
MD	Baltimore Gas & Electric	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel mains and services, cast iron mains, copper services, and pre-1982 plastic "Ski Bar" risers	Case 9331 (January 2014)
MD	Columbia Gas of Maryland	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel and cast iron mains and bare steel services	Case 9332 (August 2014)
MD	Delmarva Power & Light	Electric	Grid Resiliency Charge	Feeder hardening	Case 9317 (September 2013)
MD	Potomac Electric Power	Electric	Grid Resiliency Charge	Feeder hardening	Case 9311 (July 2013)
MD	Washington Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program Rider	Replacement of bare and unprotected steel mains and services, targeted copper and pre-1975 plastic services, mechanically coupled pipe main and services, and cast iron mains	Case 9335 (May 2014)
ME	Central Maine Power	Electric	Customer Relationship Management & Billing Rate Adjustment	Customer relationship management & billing system replacement	Docket 2015-00040 (October 2015)
ME	Maine Water Company	Water	Water Infrastructure Charge	Replacement of stationary physical plant assets needed to operate a water system	Various orders separately issued for operating divisions
ME	Northern Utilities	Gas	Targeted Infrastructure Recovery Adjustment	Cast iron, bare steel, and unprotected coated steel mains and services replacements, replacement of farm tap regulators	Docket 2013-00133 (December 2013)
MI	Consumers Energy	Gas	Enhanced Infrastructure Replacement Program	Cast iron replacements	Case U-17643 (January 2015)
MI	Michigan Consolidated Gas (now DTE Gas)	Gas	Infrastructure Recovery Mechanism	Replacement of cast iron mains, replacement of indoor meters with outdoor meters, pipeline integrity projects designed to comply with federal and state safety standards	Case U-16999 (April 2013)
MI	SEMCO Gas	Gas	Main Replacement Rider	Replacement of cast iron and unprotected steel mains and service lines	Case U-16169 and U-17824 (January 2011 and June 2015)
MN	Interstate Power & Light	Electric	Renewable Energy Recovery Adjustment	Renewable generation	Docket M-10-312 (December 2013)
MN	Minnesota Power	Electric	Arrowhead Regional Emission Abatement Rider	Miscellaneous environmental projects	Docket M-05-1678 (June 2006)
MN	Minnesota Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-07-965 (December 2007)
MN	Minnesota Power	Electric	Renewable Resource Rider	Renewable generation	Docket M-10-273 (July 2010)
MN	Minnesota Power	Electric	Rider for Boswell Unit 4 Emission Reduction	Miscellaneous environmental projects	Docket M-12-920 (November 2013)
MN	Northern States Power (Xcel Energy)	Electric	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Miscellaneous environmental projects	Docket M-02-633 (March 2004)
MN	Northern States Power (Xcel Energy)	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-06-1103 (November 2006)
MN	Northern States Power (Xcel Energy)	Electric	Renewable Energy Standard Cost Recovery Rider	Renewable generation	M-07-872 (March 2008)
MN	Northern States Power (Xcel Energy)	Gas	State Energy Policy Rider	Cast iron replacements	Docket M-08-261 (November 2008)
MN	Northern States Power (Xcel Energy)	Electric	Mercury Cost Recovery Rider	Miscellaneous environmental projects	Docket M-09-847 (November 2009)
MN	Otter Tail Power	Electric	Renewable Resource Cost Recovery Rider	Renewable generation	Docket M-08-119 (August 2008)
MN	Otter Tail Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-09-881 (January 2010)
MO	AmerenUE	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Case GT-2008-0184 (February 2008)
MO	Atmos Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GO-2009-0046 (October 2008)
MO	Laclede Gas	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2007-0208 (July 2007)
MO	Missouri American Water	Water	Infrastructure System Replacement Surcharge	Replacement of mains, associated valves and hydrants, main cleaning and relining projects	Case WO-2004-0116 (December 2003)
MO	Missouri Gas Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2009-0355 (February 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MS	Atmos Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new industrial customers for economic development	Docket 2013-UN-23 (July 2013)
MS	Centerpoint Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new commercial and industrial customers for economic development	Docket 13-UN-214 (October 2013)
MS	Mississippi Power	Electric	Enviromental Compliance Overview Plan Rate	Miscellaneous environmental projects	Docket 92-UA-0058 and 92-UN-0059 (July 1992)
MT	Northwestern Energy	Electric	NA - Amounts recovered through electric supply service rates	Generation	Docket D.2008.6.69 (November 2008)
MT	Northwestern Energy	Gas	Natural Gas Supply Tracker	Battle Creek natural gas production resources	Docket D2012.3.25 (November 2012)
NC	Aqua North Carolina	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-218, Sub 363 (May 2014)
NC	Aqua North Carolina	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-218, Sub 363 (May 2014)
NC	Carolina Water Service	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-354, Sub 336 (March 2014)
NC	Carolina Water Service	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-354, Sub 336 (March 2014)
NC	Piedmont Natural Gas	Gas	Integrity Management Rider	Investments driven by federal pipeline safety and integrity requirements	Docket G-9, Sub 631 (December 2013)
ND	Montana-Dakota Utilities	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-85 (December 2013)
ND	Montana-Dakota Utilities	Electric	Generation Resource Recovery Rider Tariff	New Generation	Case PU-14-108 (August 2014)
ND	Northern States Power- MN	Electric	Transmission Cost Rider	Transmission projects	Case PU-12-813 (February 2014)
ND	Northern States Power- MN	Electric	Renewable Energy Rider	North Dakota based renewable generation	Case PU-12-813 (February 2014)
ND	Otter Tail Power	Electric	Renewable Resource Rider	Renewables	Case PU-06-466 (May 2008)
ND	Otter Tail Power	Electric	Transmission Facility Cost Recovery Tariff	Transmission investments required to serve retail customers	Case PU-11-682 (April 2012)
ND	Otter Tail Power	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-84 (December 2013)
NE	Black Hills Nebraska Gas Utility	Gas	Infrastructure System Replacement Recovery Charge	Non-revenue increasing projects to replace existing assets	Application NG-0074
NE	SourceGas Distribution	Gas	Pipeline Replacement Charge	Projects entering service before May 2014 that are installed to comply with safety requirements as replacements for existing facilities, projects that will extend the useful life of existing assets or enhance pipeline integrity, facility relocations	Application NG-0072 (June 2013)
NE	SourceGas Distribution	Gas	System Safety and Integrity Rider	Projects entering service after April 2014 that comply with federal regulations including transmission and distribution integrity management plans or are facility relocations costing $20,000 or more	Application NG-0078 (October 2014)
NH	Aquarion Water of New Hampshire	Water	Water Infrastructure and Conservation Adjustment Charge	Projects to upgrade or replace non-revenue producing assets including main, valve, and hydrant replacement, main cleaning and relining, and non-reimbursable relocations	Docket DW 08-098 (September 2009)
NH	Energy North	Gas	Cast Iron/Bare Steel Replacement Program	Replacement of cast iron and bare steel pipe	Docket DG-107 (June 2007)
NH	Granite State Electric	Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement	Docket DG-107 (June 2007)
NH	Public Service Company of New Hampshire	Electric	Energy Service	Miscellaneous environmental projects	DE 11-250 (April 2012)
NH	Public Service Company of New Hampshire	Electric	Reliability Enhancement Plan	Reliability improvements	DE 09-035, DE 11-250, and DE 14-238 (June 2015)
NJ	Elizabethtown Gas	Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort	System hardening	Docket GO13090826 (July 2014)
NJ	New Jersey American Water	Water	Distribution System Improvement Charge	Incremental non-revenue water main replacement, rehabilitation, or mandated relocation projects, service line replacements, valve and hydrant replacement	Docket WR12070669 (October 2012)
NJ	New Jersey Natural Gas	Gas	New Jersey Reinvestment in System Enhancement	Storm hardening projects	Docket GR13090828 (July 2014)
NJ	Public Service Electric and Gas	Electric	Solar Generation Investment Program	Solar generation	Docket EO09020125 (August 2009)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Dockets GO09010050, EO11020088, GO10110862 (April 2009 and July 2011)
NJ	Public Service Electric and Gas	Electric & Gas	Energy Strong Adjustment Mechanism	Electric: substation flood mitigation, gird reconfiguration strategies, and smart grid; Gas: Metering and regulating station flood mitigation, replacement of utilization pressure cast iron in flood prone areas	Docket EO13020155, GO13020156 (May 2014)
NJ	South Jersey Gas	Gas	Storm Hardening and Reliability Program	Replacement of low pressure mains and services with high pressure mains and services, removal of regulator stations, installation of excess flow valves in coastal areas	Docket GO13090814 (August 2014)
NJ	United Water New Jersey	Water	Distribution System Improvement Charge	Repair, replace, and/or clean mains, replace valves, hydrants, and service lines	Docket WR12080724 (October 2012)
NV	Southwest Gas	Gas	Gas Infrastructure Replacement Mechanism	Early vintage pipe replacements, conversion of master metered customers to individual meters	Docket 14-10002 (December 2014)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
NY	Corning Natural Gas	Gas	Safety and Reliability Charge	Replacement of leak prone pipe and ancillary costs to maintain a safe and reliable system	Case 11-G-0280 (October 2015)
NY	Keyspan Energy Long Island	Gas	Leak Prone Pipe Surcharge	Accelerated leak prone pipe removal program	Case 12-G-0214 (December 2014 and March 2015)
NY	Long Island American Water	Water	System Improvement Charge	Iron removal, storage tank rehabilitiation, suction well rehabilitation at selected plants, customer information system	Case 11-W-0200 (March 2012)
NY	United Water New Rochelle	Water	Long Term Main Renewal Project	Cleaning and relining of mains	Case 99-W-0948 (August 2000)
NY	United Water New York	Water	Underground Infrastructure Renewal Program	Replacement of infrastructure including mains, valves, services, meters, and hydrants	Case 06-W-0131 (December 2006)
NY	United Water New York	Water	New Water Supply Source Surcharge	Projects to provide new sources of water in the short and long term	Case 06-W-0131 (December 2006)
OH	Aqua Ohio	Water	System Infrastructure Improvement Surcharge	Replacement of service lines, mains, hydrants, valves, main extensions to resolve documented water supply problems	Case 04-1824-WW-SIC (March 2005)
OH	Cleveland Electric Illuminating	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Cleveland Electric Illuminating	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case	Case 10-388-EL-SSO (August 2010)
OH	Columbia Gas	Gas	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, AMI	Cases 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case 09-1036-GA-RDR (April 2010)
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services and faulty risers	1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Cases 07-0589-GA-AIR, 07-0590-GA-ALT, and 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Electric	Infrastructure Modernization Distribution Rider	Electric AMI	Cases 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Duke Energy Ohio	Electric	Distribution Capital Investment Rider	Distribution capital investments not recovered through other trackers	Case 14-841-EL-SSO (April 2015)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Bare steel and cast iron pipelines & faulty riser replacements	Case 08-169-GA-ALT (October 2008)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMR	Cases 07-0829-GA-AIR and 06-1453-GA-UNC (October 2008); Case 09-38-GA-UNC (May 2009); Case 09-1875-GA-RDR (May 2010)
OH	Ohio American Water	Water	System Improvement Charge	Non-revenue producing service lines, hydrants, mains, valves, main extensions that improve supply problems, main cleaning	Case 05-577-WW-SIC (August 2005)
OH	Ohio Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Ohio Edison	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Ohio Power	Electric	Distribution Investment Rider	Net distribution capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Ohio Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Toledo Edison	Electric	Delivery Capital Recovery Rider	Power distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Gas	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Cases 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening	Cause PUD 20080387, Order 567670 (May 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Smart grid	Cause PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Electric	Crossroads Rider	Crossroads Wind Farm	Cause PUD 201000037 (July 2010)
OK	Public Service Company of Oklahoma	Electric	System Reliability Rider	Grid resiliency projects	Cause PUD 201300202 (January 2014)
OK	Public Service Company of Oklahoma	Electric	Advanced Metering Infrastructure Tariff	Advanced metering infrastructure deployment	Cause PUD 201300217 (April 2015)
OR	Northwest Natural Gas	Gas	System Integrity Program	Bare steel replacement, transmission integrity management program, distribution integrity management program	Docket UM 1406, Order 09-067 (March 2009)
OR	PacifiCorp	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
OR	PacifiCorp	Electric	Lake Side 2 Tariff Rider	Generation	Docket UE 263, Order 13-474 (December 2013)
OR	PacifiCorp	Electric	M2O Transmission Rider	Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013	Docket UE 246, Orders 12-493 and 13-195 (December 2012 and May 2013)
OR	Portland General Electric	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
PA	Columbia Gas	Gas	Distribution System Improvement Charge	Replacement of cast iron, bare steel, and first generation plastic mains and services, install excess flow valves, install or relocate automated meters, and replace risers, meter bars, and service regulators	P-2012-2338282 (March 2013)
PA	Columbia Water Company	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-00021979
PA	Duquesne Light	Electric	Smart Meter Charge Rider	AMI	Docket M-2009-2123948 (April 2010)
PA	Equitable Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2342745 (July 2013)
PA	Metropolitan Edison	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
PA	PECO	Electric	Smart Meter Cost Recovery Rider	AMI	Docket M-2009-2123944 (April 2010)
PA	PECO	Electric	Distribution System Improvement Charge	Storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations	Docket P-2015-2471423 (October 2015)
PA	PECO	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2347340 (September 2015)
PA	Pennsylvania Electric	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania-American Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-000961031 (August 1996)
PA	Peoples Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344596 (May 2013)
PA	Peoples TWP	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344595 (May 2013)
PA	Philadelphia Gas Works	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2012-2337737 (April 2013)
PA	Philadelphia Surburban Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-00961035 (August 1996)
PA	PPL Electric Utilities	Electric	Act 129 Compliance Rider	AMI	Docket M-2009-2123945 (January 2010)
PA	PPL Electric Utilities	Electric	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., poles, wires)	Docket P-2012-2325034 (May 2013)
PA	UGI Central Penn Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2398835 (September 2014)
PA	UGI Penn Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2397056 (September 2014)
PA	West Penn Power	Electric	Smart Meter Surcharge	AMI	Docket M-2009-2123951 (June 2011)
RI	Narragansett Electric (electric operations)	Electric	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth	Docket 4218 (December 2011)
RI	Narragansett Electric (gas operations)	Gas	Gas Infrastructure, Safety, and Reliability Plan Factor	Previous accelerated capital replacement program investments plus main and service replacements and reliability investments	Docket 4219 (September 2011)
SC	South Carolina Electric & Gas	Electric	NA	Nuclear generation	Docket 2008-196-E (March 2009)
SD	Black Hills Power	Electric	Environmental Improvement Adjustment tariff	Miscellaneous environmental projects	Docket EL11-001
SD	Black Hills Power	Electric	Phase in plan rate	Gas-fired generation	Docket EL12-062 (September 2013)
SD	Northern States Power- MN	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL07-026 (January 2009)
SD	Northern States Power- MN	Electric	Transmission Cost Recovery Tariff	Transmission	Docket EL07-007 (January 2009)
SD	Northern States Power- MN	Electric	Infrastructure Rider	Generation	Docket EL 12-046 (April 2013)
SD	Otter Tail Power	Electric	Transmission Cost Recovery Tariff	Retail sales portion of specific transmission projects	Docket EL 10-015 (November 2011)
SD	Otter Tail Power	Electric	Environmental Quality Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL 14-082 (December 2014)
TN	Piedmont Natural Gas	Gas	Integrity Management Rider	Distribution and transmission integrity management planning as required by the US Department of Transportation	Docket 13-00118 (May 2014)
TX	AEP Texas Central	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	AEP Texas North	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	Atmos Energy Mid Tex	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy Pipelines	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Gas Utilities Dockets 9615 and 10640
TX	Atmos Energy West Texas Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9608
TX	Centerpoint Energy Entex - Houston Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 10067
TX	Centerpoint Energy Houston Electric	Electric	Advanced Metering System Surcharge	AMI	Docket 35620 (August 2008)
TX	Centerpoint Energy Houston Electric	Electric	Distribution Cost Recovery Factor	Change in net distribution rate base since last rate case	Docket 44572 (August 2015)
TX	Oncor Electric Delivery	Electric	Advanced Metering System Surcharge	AMI	Docket 35718 (August 2008)
TX	Texas-New Mexico Power	Electric	Advanced Metering System Surcharge	AMI	Docket 38306 (July 2011)
UT	Questar Gas	Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Electric	Environmental & Reliability Cost Recovery Surcharge	Miscellaneous environmental & reliability projects	Docket PUE-2007-00069 (December 2007)
VA	Appalachian Power	Electric	Environmental Rate Adjustment Clause	Miscellaneous environmental projects	Case PUE-2011-00035 (November 2011)
VA	Appalachian Power	Electric	Generation Rate Adjustment Clause	Dresden plant	Docket PUE-2011-00036 (January 2012)
VA	Atmos Energy	Gas	Infrastructure Reliability and Replacement Adjustment	Replacement of first generation plastic pipe and service lines and bare steel mains and services	Case PUE-2012-00049 (August 2012)
VA	Columbia Gas of Virginia	Gas	SAVE Rider	Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure	Case PUE-2011-00049 (November 2011)
VA	Roanoke Gas Company	Gas	SAVE Rider	Replacement of cast iron mains, bare steel mains and services and pre-1973 plastic pipe	Case PUE-2012-00030 (August 2012)
VA	Virginia Electric Power	Electric	Rider S	Virginia City Hybrid Energy Center	Case PUE-2007-00066 (March 2008)
VA	Virginia Electric Power	Electric	Rider R	Bear Garden Generating Station	Case PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Electric	Rider W	Warren County Power Station	Case PUE-2011-00042 (February 2012)
VA	Virginia Electric Power	Electric	Rider B	Biomass conversions	Case PUE-2011-00073 (March 2012)
VA	Virginia Electric Power	Electric	Rider BW	Brunswick County Power Station (natural gas combined cycle generating station)	Case PUE-2012-00128 (August 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
VA	Virginia Natural Gas	Gas	SAVE Rider	Replacement of first generation plastic mains, cast and wrought iron mains, bare and ineffectively coated steel mains, and service lines installed prior to 1971	Case PUE-2012-00012 (June 2012)
VA	Washington Gas Light	Gas	SAVE Rider	Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and pre-1975 plastic services	Cases PUE-2010-00087 and PUE-2012-00096 (April 2011 and November 2012)
WA	Cascade Natural Gas	Gas	Pipeline Replacement Program Cost Recovery Mechanism	Replacement of bare steel and poorly coated pipelines and distribution systems	Docket PG-131838 (October 2013)
WV	Appalachian Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WV	Monongahela Power	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Potomac Edison	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Wheeling Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WY	Black Hills Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20002-84-ET-12 (November 2012)
WY	Cheyenne Light, Fuel, & Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20003-123-ET-12 (November 2012)

III. Relaxing the Link Between Revenue and System Use

Policymakers are increasingly interested in relaxing the link between the revenues utilities realize, and the kWh and kW of system use by customers. This reduces the financial attrition that results from slowing growth in system use (given legacy rate designs) more efficiently than frequent rate cases. In addition, utilities have more incentive to embrace DSM. Three approaches to relaxing the revenue/usage link are well established: lost revenue adjustment mechanisms ("LRAMs"), revenue decoupling, and fixed/variable pricing.

A. Lost Revenue Adjustment Mechanisms

LRAMs keep utilities whole for short-term losses in base rate revenues that are due to their DSM programs (and potentially also DG). Recovery usually is effected through a special rate rider. Estimates of load losses are needed.

LRAMs encourage utilities to embrace DSM that is eligible for LRAM treatment. They do not provide recovery for the revenue impact of external forces, like DSM programs managed by independent agencies, which slow load growth. Estimates of load savings from utility DSM can be complex and are sometimes controversial. The scope of DSM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. When usage charges are high, the utility remains at risk for revenue fluctuations in volumes and peak load due to weather, local economic activity, and other volatile demand drivers.

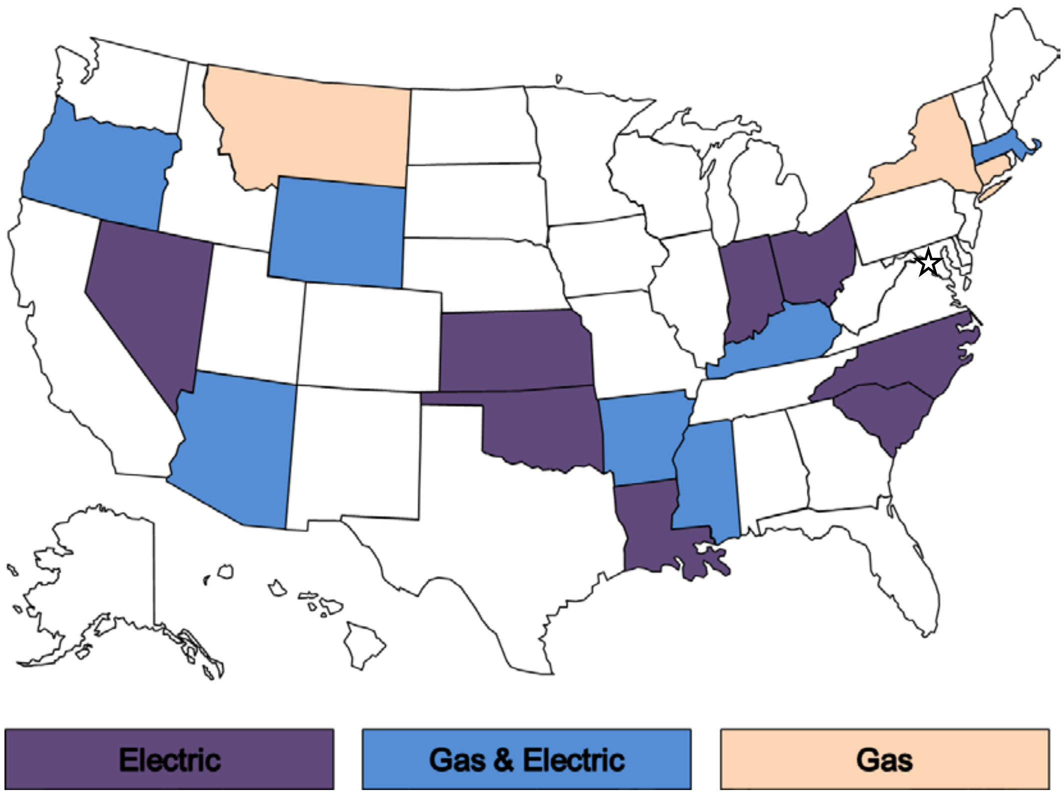
Precedents for LRAMs are detailed in Table 3 and Figure 4 below.[3] LRAMs are currently the most popular means of relaxing the link between revenue and system use in the US electric utility industry. Since our 2013 survey, LRAMs have been adopted for electric utilities in Arizona, Louisiana, and Mississippi. A few utilities have LRAMs that address DG. LRAMs are less popular for gas distributors since the declining average use they have typically experienced for many years is due chiefly to external forces that LRAMs don't address. Some utilities have LRAMs for some services and revenue decoupling for others. In New York, for example, some natural gas distributors have decoupling for residential and commercial customers and LRAMs for some large load customers.

B. Revenue Decoupling

Revenue decoupling adjusts a utility's rates periodically to help its actual revenue track its allowed revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue and adjusts rates to reduce them. The RAM escalates allowed revenue to provide relief for growing cost pressures.

[3] Some mechanisms similar to LRAMs are excluded from this survey.

Figure 4: Current LRAMs by State



RDMs can make true ups annually or more frequently. More frequent adjustments cause actual revenue to track allowed revenue more closely so that rate adjustments are smaller. The size of the rate adjustment that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery account balances that cannot be drawn down immediately. A "hard" cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue and are often the primary focus of DSM programs. RDMs also vary in terms of the services for which revenues are pooled for true up purposes. In some plans all services are placed in the same "basket." Other plans have multiple baskets, and these insulate customers of services in each basket from changes in revenue for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between allowed revenue and weather normalized actuals. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism.

Table 3

Current LRAM Precedents[1]

State	Company	Services	Approval Date	Case Reference
AR	Arkansas Oklahoma Gas	Gas	June 2011	Docket 07-077-TF, Order Number 30
AR	Centerpoint Energy Arkla	Gas	June 2011	Docket 07-081-TF, Order Number 31
AR	Entergy Arkansas	Electric	June 2011	Docket 07-085-TF, Order Number 40
AR	Oklahoma Gas & Electric	Electric	June 2011	Docket 07-075-TF, Order 26
AR	SourceGas Arkansas	Gas	June 2011	Docket 07-078-TF, Order 26
AR	Southwestern Electric Power	Electric	June 2011	Docket 07-082-TF, Orders 35 and 36
AZ	Arizona Public Service	Electric	May 2012	Docket E-01345A-11-0224, Decision 73l83
AZ	Tucson Electric Power	Electric	June 2013	Docket E-01933A-12-0291; Decision 73912
AZ	UNS Electric	Electric	September 2013	Docket E-04204A-12-0504; Decision 74235
AZ	UNS Gas	Gas	May 2012	Docket G-04204A-11-0158 Decision 73142
CT	Southern Connecticut Gas	Gas	August 1995	Docket 93-03-09
CT	Yankee Gas Service	Gas	January 2012	Docket 11-10-03
IN	Duke Energy Indiana (PSI)	Electric	February 2010	Cause 43374
IN	Indiana-Michigan Power	Electric	September 2010	Cause 43827
IN	Northern Indiana Public Service	Electric	May 2011	Cause 43618
IN	Southern Indiana Gas & Electric	Electric	August 2011 (large commercial and industrials), June 2012 (residential and small commercial)	Causes 43938 and 43405 DSMA 9 S1
KS	Kansas Gas & Electric	Electric	January 2011	Docket 10-WSEE-775-TAR
KS	Westar Energy	Electric	January 2011	Docket 10-WSEE-775-TAR
KY	Atmos Energy	Gas	September 2009	Case 2008-00499
KY	Columbia Gas of Kentucky	Gas	October 2009	Case 2009-00141
KY	Delta Natural Gas	Gas	July 2008	Docket 2008-00062
KY	Duke Energy Kentucky	Electric	December 1995 and February 2005	Cases 95-321 and 2004-00389
KY	Duke Energy Kentucky	Gas	February 2005	Case 2004-00389
KY	Kentucky Power	Electric	December 1995	Case 95-427
KY	Kentucky Utilities	Electric	May 2001	Case 2000-0459
KY	Louisville Gas & Electric	Electric & Gas	November 1993	Case 93-150
LA	Cleco Power	Electric	October 2014	Docket R-31106
LA	Entergy Gulf States Louisiana	Electric	October 2014	Docket R-31106
LA	Entergy Louisiana	Electric	October 2014	Docket R-31106
LA	Southwestern Electric Power	Electric	October 2014	Docket R-31106
MA	All Electric distributors	Electric	July 2012	D.P.U. 12-01A
MA	Berkshire Gas	Gas	October 1992	D.P.U. 91-154
MA	Commonwealth Gas d/b/a NSTAR Gas	Gas	November 1994	D.P.U. 94-128

Table 3 (cont'd)

State	Company	Services	Approval Date	Case Reference
MA	NSTAR Electric	Electric	April 1992, June 1994, and June 2010	D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06
MS	Atmos Energy	Gas	August 2014	Docket 2014-UA-017
MS	Centerpoint Energy	Gas	August 2014	Docket 2014-UA-007
MS	Entergy Mississippi	Electric	September 2014	Docket 2009-UN-064
MS	Mississippi Power	Electric	March 2015	Docket 2014-UN-10
MT	Montana-Dakota Utilities	Gas	October 2006	Docket D2005.10.156; Order 6697c
NC	Duke Energy Carolinas	Electric	February 2010	Docket E-7, Sub 831
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	November 2009	Docket E-2, Sub 931
NC	Virginia Electric Power	Electric	October 2011	Docket E-22, Sub 464
NV	Nevada Energy	Electric	May 2011	Docket 10-10024
NV	Sierra Pacific Power	Electric	May 2011	Docket 10-10025
NY	Keyspan Long Island	Gas	December 2009	Case 06-G-1186; Currently effective for all customers not in RDM
NY	Keyspan New York	Gas	December 2009	Case 06-G-1185; Currently effective for all customers not in RDM
OH	American Electric Power (Ohio Power, Columbus Southern Power)	Electric	May 2010	Docket 09-1089-EL-POR; Effective for classes not included in RDM
OH	Dayton Power & Light	Electric	June 2009	Docket 08-1094-EL-SSO
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	July 2007 and August 2012	Dockets 06-0091-EL-UNC and 11-4393-EL-RDR; Effective for classes not included in RDM
OH	First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison)	Electric	March 2009	Docket 08-935-EL-SSO
OK	Empire District Electric	Electric	November 2009	Cause 200900146 Order 571326
OK	Oklahoma Gas & Electric	Electric	July 2008	Cause 200800059 Order 556179
OK	Public Service of Oklahoma	Electric	January 2010	Cause PUD 200900196; Order 572836
OR	Cascade Natural Gas	Gas	April 2006	Order 06-191; UG 167 Effective for classes not included in RDM
OR	Portland General Electric	Electric	September 2001	Order 01-836; UE 79 Effective for classes not included in RDM
OR	Avista Utilities	Gas	December 1993	Order 93-1881
SC	Duke Energy Carolinas	Electric	January 2010	Docket 2009-226-E Order 2010-79
SC	Progress Energy Carolinas	Electric	June 2009	Docket 2008-251-E Order 2009-373
SC	South Carolina Electric & Gas	Electric	July 2010	Docket 2009-261-E, Order 2010-472
WY	Cheyenne Light, Fuel, and Power	Electric & Gas	September 2011	Dockets 20003-108-EA-10 and 30005-140-GA-10
WY	Montana-Dakota Utilities	Electric	January 2007	Docket 20004-65-ET-06

[1] LRAMs listed here include only those mechanisms that compensate utilities for actual revenues lost due to DSM and DG.

The great majority of decoupling systems have a RAM since, if allowed revenue is static, the utility will experience financial attrition as its costs inevitably rise. Utilities that do not have RAMs in their decoupling systems often file frequent rate cases or are allowed to use capital cost trackers to address attrition. The more important issue in a proceeding to consider decoupling is therefore the design of the RAM rather than the need for one.

Most RAMs escalate allowed revenue only for customer growth. Escalation for customer growth is sensible because it is an important driver of cost and also highly correlated with other drivers such as peak demand. The need for rate cases is thereby reduced but is rarely eliminated since cost has other drivers such as input price inflation. When RAMs are escalated only for customer growth, utilities usually retain the freedom to file rate cases to address other cost factors and often do. Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can materially reduce the need for rate cases and provide a foundation for a multiyear rate plan.

Revenue decoupling compensates utilities for declining average use even if it is driven in part by external forces such as independently administered DSM programs. The lost revenue disincentive is removed for a wide array of utility initiatives to encourage DSM without requiring load impact calculations or rate designs that discourage DSM. To the extent that recovery of allowed revenue is ensured, utilities can use rate designs with usage charges more aggressively to foster DSM. This makes environmental intervenors strong supporters of decoupling. Controversy over billing determinants in rate cases with future test years is reduced.

Revenue decoupling is a popular means of relaxing the link between a utility's revenue and customers' kWh consumption. States that have tried gas and electric revenue decoupling are indicated on the maps below in Figures 5a and 5b, respectively. Revenue decoupling precedents in the United States and Canada are detailed in Table 4. In the electric utility industry, decoupling has been favored in states that strongly support DSM. Since our 2013 survey, decoupling has been adopted for electric utilities in Connecticut, Maine, Minnesota, and Washington state. Decoupling is the most widespread means of relaxing the revenue/usage link for gas distributors. This reflects the fact that gas distributors often experience declining average use and that this has been driven chiefly by external forces. Table 4 indicates the kinds of RAMs chosen in approved decoupling systems. Note that RAMs for electric utilities are frequently broad-based.

C. Fixed/Variable Pricing

Fixed/variable pricing is an approach to rate design that uses fixed charges (charges that do not vary with the actual sales volume or peak demand) to compensate utilities for fixed costs of service. For residential and small commercial services, customer charges (a flat monthly fee per customer) are the most common fixed charge used. Base revenue thus tends to grow at the gradual pace of customer growth. A *straight* fixed/variable ("SFV") rate design recovers *all* base revenue through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed/variable pricing.

Figure 5a: Electric Revenue Decoupling by State

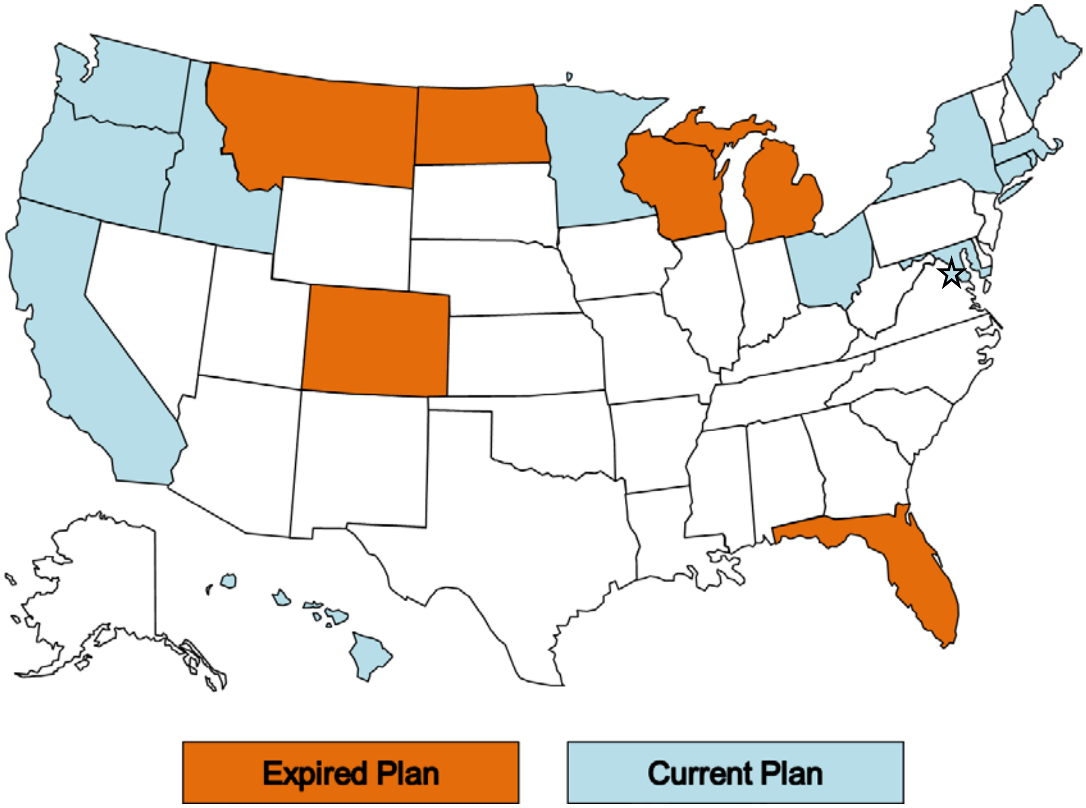


Figure 5b: Gas Revenue Decoupling by State

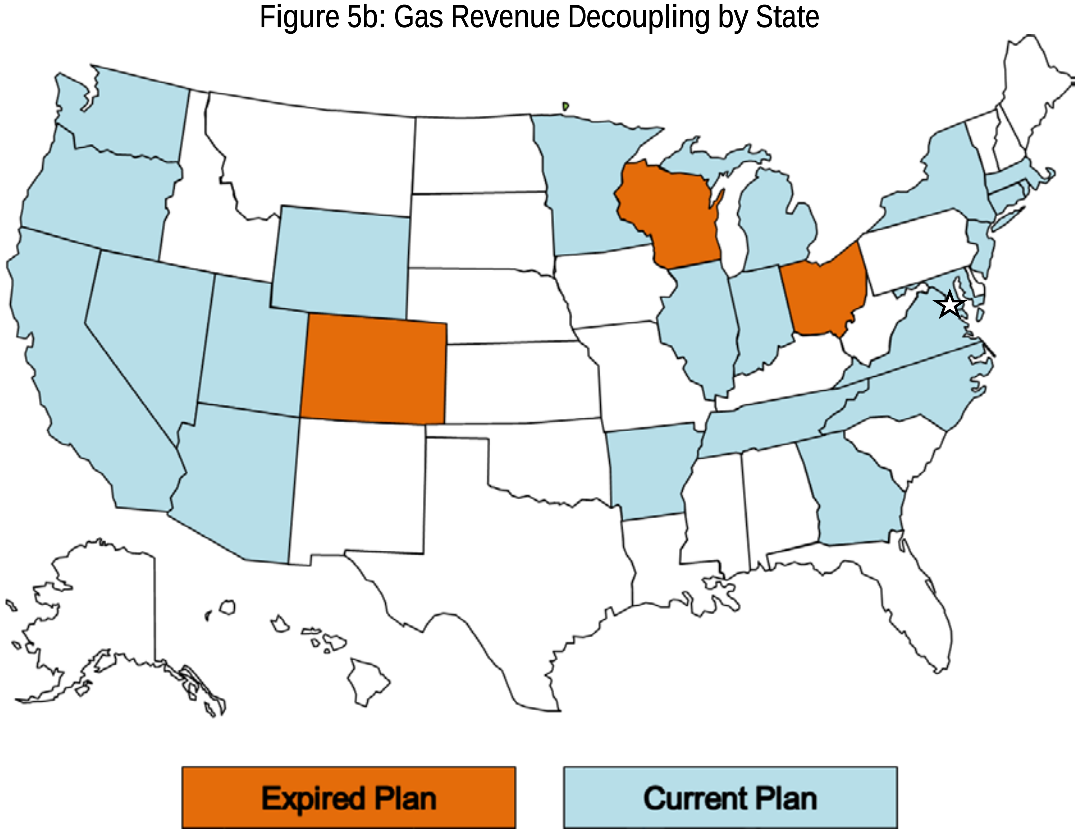


Table 4

Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current					
United States					
AR	Arkansas Oklahoma Gas	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-078-U
AR	CenterPoint Energy	Gas	2008-2016	No RAM but multiple capital cost trackers	Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF
AR	SourceGas Arkansas (Arkansas Western)	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-079-U
AZ	Southwest Gas	Gas	2012-open	Customers	Docket G-01551A-10-0458
CA	Bear Valley Electric Service	Electric	2013-2016	Stairstep	Decision 14-11-002
CA	California Pacific Electric	Electric	2013-2015	Indexing	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2014-2016	Stairstep	Decision 14-08-032
CA	San Diego Gas & Electric	Gas & Electric	2012-2015	Stairstep	Decision 13-05-010
CA	Southern California Edison	Electric	2012-2014	Hybrid	Decision 12-11-051
CA	Southern California Gas	Gas	2012-2015	Stairstep	Decision 13-05-010
CA	Southwest Gas	Gas	2014-2018	Stairstep	Decision 14-06-028
CT	Connecticut Light & Power	Electric	2014-open	No RAM	Docket 14-05-06
CT	Connecticut Natural Gas	Gas	2014-open	No RAM	Docket 13-06-08
CT	United Illuminating	Electric	2013-open	Stairstep until July 2015, No RAM thereafter	Docket 13-01-19
DC	Potomac Electric Power	Electric	2010-open	Customers	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	Dockets 2008-0274, 2008-0083, 2013-0141
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0164, 2013-0141
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163, 2013-0141
ID	Idaho Power	Electric	2012-open	Customers	Cases IPC-E-11-19, IPC-E-14-17
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM but broad-based capital cost tracker	Case 11-0281
IN	Citizens Gas	Gas	2007-open	Customers	Cause 42767
IN	Indiana Gas	Gas	2011-2015	Customers	Cause 44019
IN	Indiana Gas	Gas	2016-2019	Customers	Cause 44598
IN	Indiana Natural Gas	Gas	2014-open	Customers	Cause 44453
IN	Vectren Southern Indiana	Gas	2011-2015	Customers	Cause 44019
IN	Vectren Southern Indiana	Gas	2016-2019	Customers	Cause 44598
MA	Bay State Gas	Gas	2015-2018	Revenue per Customer Stairstep	DPU 15-50
MA	Boston-Essex Gas	Gas	2010-open	Customers	DPU 10-55
MA	Colonial Gas	Gas	2010-open	Customers	DPU 10-55
MA	Fitchburg Gas & Electric	Gas	2011-open	Customers	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capital cost tracker	DPU 09-39
MA	New England Gas	Gas	2011-open	Customers	DPU 10-114
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MD	Baltimore Gas & Electric	Electric	2008-open	Customers	Letter Orders ML 108069, 108061
MD	Baltimore Gas & Electric	Gas	1998-open	Customers	Case 8780
MD	Chesapeake Utilities	Gas	2006-open	Customers	Order 81054
MD	Columbia Gas of Maryland	Gas	2013-open	Customers	Order 85858
MD	Delmarva Power & Light	Electric	2007-open	Customers	Order 81518
MD	Potomac Electric Power	Electric	2007-open	Customers	Order 81517
MD	Washington Gas Light	Gas	2005-open	Customers	Order 80130
ME	Central Maine Power	Electric	2014-open	Customers	Docket 2013-00168

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
United States (cont'd)					
MI	Consumers Energy	Gas	2015-open	No RAM	Case U-17643
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case U-16999
MI	Michigan Gas Utilities	Gas	2015-open	No RAM	Case U-17273
MN	CenterPoint Energy	Gas	2015-2018	Customers	GR-13-316
MN	Minnesota Energy Resources	Gas	2013-2016	Customers	GR-10-977
MN	Northern States Power - MN	Electric	2016-2018	Customers	GR-13-868
NC	Piedmont Natural Gas	Gas	2008-open	Customers	Docket G-9, Sub 550
NC	Public Service Co of NC	Gas	2008-open	Customers	Docket G-5, Sub 495
NJ	New Jersey Natural Gas	Gas	2014-open	Customers	Docket GR13030185
NJ	South Jersey Gas	Gas	2014-open	Customers	Docket GR13030185
NV	Southwest Gas	Gas	2009-open	Customers	D-09-04003
NY	Central Hudson G&E	Gas & Electric	2015-2018	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	Gas	2014-2016	Revenue per Customer Stairstep	Case 13-G-0031
NY	Consolidated Edison	Electric	2014-2016	Stairstep	Case 13-E-0030
NY	Corning Natural Gas	Gas	2015-2017	Customers	Case 11-G-0280
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery New York	Gas	2013-2014	Revenue per Customer Stairstep through 2014, Customers After 2014	Case 12-G-0544
NY	National Fuel Gas	Gas	2013-2015	Customers	Case 13-G-0136
NY	New York State Electric & Gas	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0715
NY	New York State Electric & Gas	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0716
NY	Niagara Mohawk	Gas	2013-2016	Optional Revenue per Customer Stairstep	Case 12-G-0202
NY	Niagara Mohawk	Electric	2013-2016	Optional Stairstep	Case 12-E-0201
NY	Orange & Rockland Utilities	Gas	2015-2018	Revenue per Customer Stairstep	Case 14-G-0494
NY	Orange & Rockland Utilities	Electric	2015-2017	Stairstep	Case 14-E-0493
NY	Rochester Gas & Electric	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0717
NY	Rochester Gas & Electric	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0718
NY	St. Lawrence Gas	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers thereafter	Case 08-G-1392
OH	AEP Ohio	Electric	2012-2018	Customers	Cases 11-351-EL-AIR, 13-2385-EL-SSO
OH	Duke Energy Ohio	Electric	2015-open	Customers	Case 14-841-EL-SSO
OR	Cascade Natural Gas	Gas	2013-2015	Customers	Order 13-079
OR	Northwest Natural Gas	Gas	2012-open	Customers	Order 12-408
OR	Portland General Electric	Electric	2014-2016	Customers	Order 13-459
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capital cost tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	Customers	Docket 4206
TN	Chattanooga Gas	Gas	2013-open	Customers	Docket 09-0183
UT	Questar Gas	Gas	2010-open	Customers	Docket 09-057-16
VA	Columbia Gas of Virginia	Gas	2013-2015	Customers	Case PUE-2012-00013
VA	Virginia Natural Gas	Gas	2013-2016	Customers	Case PUE-2012-00118
VA	Washington Gas Light	Gas	2013-2016	Customers	Case PUE-2012-00138
WA	Avista	Gas & Electric	2015-2019	Customers	Dockets UE-140188 and UG-140189
WA	Puget Sound Energy	Gas & Electric	2013-2016	Revenue per Customer Stairstep	Dockets UE-121697 and UG-121705
WY	Questar Gas	Gas	2012-open	Customers	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	Customers	Docket 30022-148-GR-10

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
Canada					
BC	BC Hydro	Electric	2015-2016	Stairstep	Order G-48-14
BC	FortisBC	Electric	2014-2019	Indexing	Order G-139-14
BC	FortisBC Energy	Gas	2014-2019	Indexing	Order G-138-14
BC	Pacific Northern Gas	Gas	2003-open	Customers	N/A
ON	Enbridge Gas Distribution	Gas	2014-2018	Stairstep	EB-2012-0459
ON	Union Gas	Gas	2014-2018	Indexing	EB-2013-0202
Historic					
United States					
AR	Arkansas Oklahoma Gas	Gas	2007-2013	No RAM	Dockets 07-026-U, 07-077-TF
AR	Arkansas Western	Gas	2008-2013	No RAM	Docket 07-078-TF
CA	Bear Valley Electric Service	Electric	2009-2012	Stairstep	Decision 09-10-028
CA	Pacific Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93887
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	Pacific Gas & Electric	Gas & Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Pacific Gas & Electric	Gas & Electric	2004-2006	Indexing	Decision 04-05-055
CA	Pacific Gas & Electric	Gas & Electric	2007-2010	Stairstep	Decision 07-03-044
CA	Pacific Gas & Electric	Gas & Electric	2011-2013	Stairstep	Decision 11-05-018
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316, 91107
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	San Diego Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93892
CA	San Diego Gas & Electric	Gas & Electric	1986-1988	Hybrid	Decision 85-12-108
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	San Diego Gas & Electric	Gas & Electric	1994-1999	Hybrid	Decision 94-08-023
CA	San Diego Gas & Electric	Gas & Electric	2005-2007	Indexing	Decision 05-03-025
CA	San Diego Gas & Electric	Gas & Electric	2008-2011	Stairstep	Decision 08-07-046
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Edison	Electric	2001-2003	Indexing	Decision 02-04-055
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Gas	Gas	1979-1980	No RAM	Decision 89710
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1983-1984	Hybrid	Decision dated December 8, 1982
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Southern California Gas	Gas	1998-2002	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	2005-2007	Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CO	Public Service Company of Colorado	Gas	2008-2011	Customers	Decision C07-0568
CO	Public Service Company of Colorado	Electric	2012-2014	Stairstep	Decision C12-0494
CT	United Illuminating	Electric	2009-2013	Stairstep until 2011/No RAM for 2011 onwards	Docket 08-07-04
FL	Florida Power Corporation	Electric	1995-1997	Customers	Docket 930444
ID	Idaho Power	Electric	2007-2009	Customers	Case IPC-E-04-15
ID	Idaho Power	Electric	2010-2012	Customers	Case IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	Customers	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	Customers	Case 07-0242
IN	Citizens Gas	Gas	2007-2011	Customers	Cause 42767
IN	Vectren Energy	Gas	2007-2011	Customers	Cause 43046
IN	Vectren Southern Indiana	Gas	2007-2011	Customers	Cause 43046
MA	Bay State Gas	Gas	2009-open	Customers	DPU 09-30
ME	Central Maine Power	Electric	1991-1993	Customers	Docket 90-085
MI	Consumers Energy	Electric	2009-2011	Customers	Case U-15645
MI	Consumers Energy	Gas	2010-2012	Customers	Case U-15986
MI	Detroit Edison	Electric	2010-2011	Customers	Case U-15768
MI	Michigan Consolidated Gas	Gas	2010-2012	Customers	Case U-15985
MI	Michigan Gas Utilities	Gas	2010-2013	Customers	Case U-15990
MI	Upper Peninsula Power	Electric	2010-2011	Customers	Case U-15988
MN	CenterPoint Energy	Gas	2010-2013	Customers	Docket GR-08-1075
MT	Montana Power Company	Electric	1994-1998	Customers	Docket 93.6.24

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
United States (cont'd)					
NC	Piedmont Natural Gas	Gas	2005-2008	Customers	Docket G-44 Sub 15
ND	Northern States Power - MN	Electric	2012	Not Applicable, plan only 1 year in duration	Case PU-11-55
NJ	New Jersey Natural Gas	Gas	2007-2010	Customers	Docket GR05121020
NJ	New Jersey Natural Gas	Gas	2010-2013	Customers	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	Customers	Docket GR05121019
NJ	South Jersey Gas	Gas	2010-2013	Customers	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	Customers	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009	No RAM	Case 08-E-0887
NY	Central Hudson G&E	Gas & Electric	2010-2013	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Case 09-E-0588
NY	Central Hudson G&E	Gas & Electric	2013-open	Customers for Gas, No RAM for Electric	Case 12-M-0192
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion 92-8
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2010-2013	Revenue per Customer Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Corning Natural Gas	Gas	2012-2015	Revenue per Customer Stairstep	Case 11-G-0280
NY	Keyspan Energy Delivery - New York	Gas	2010-open	Revenue per Customer Stairstep	Case 06-G-1185
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion 92-8
NY	National Fuel Gas	Gas	2008-open	Customers	Case 07-G-0141
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion 93-22
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
NY	Niagara Mohawk	Gas	2009-open	Customers	Case 08-G-0609
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	Orange & Rockland Utilities	Electric	2012-2015	Stairstep	Case 11-E-0408
NY	Orange & Rockland Utilities	Electric	2011-2012	No RAM	Case 10-E-0362
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Orange & Rockland Utilities	Gas	2012-2015	Customers	Case 08-G-1398
NY	Orange & Rockland Utilities	Gas	2009-2012	Revenue per Customer Stairstep	Case 08-G-1398
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion 93-19
OH	Duke Energy Ohio	Electric	2012-2014	Customers	Case 11-5905-EL-RDR
OH	Vectren Energy	Gas	2007-2009	Customers	Case 05-1444-GA-UNC
OR	Cascade Natural Gas	Gas	2007-2012	Customers	Order 06-191
OR	Northwest Natural Gas	Gas	2002-2005	Customers	Order 02-634
OR	Northwest Natural Gas	Gas	2005-2009	Customers	Order 05-934
OR	Northwest Natural Gas	Gas	2009-2012	Customers	Order 07-426
OR	PacifiCorp	Electric	1998-2001	Indexing	Order 98-191
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order 95-0322
OR	Portland General Electric	Electric	2009-2010	Customers	Order 09-020
OR	Portland General Electric	Electric	2011-2013	Customers	Order 10-478
TN	Chattanooga Gas	Gas	2010-2013	Customers	Docket 09-0183
UT	Questar Gas	Gas	2006-2010	Customers	Docket 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	Customers	Case PUE-2008-00060
VA	Washington Gas Light	Gas	2010-2013	Customers	Case PUE-2009-00064
WA	Avista	Gas	2007-2009	Customers	Docket UG-060518
WA	Avista	Gas	2009-2012	Customers	Docket UG-060518
WA	Avista	Gas	2013-2014	Revenue per Customer Stairstep	Docket UG-120437
WA	Cascade Natural Gas	Gas	2005-2010	Customers	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	Customers	Docket UE-901184-P
WI	Wisconsin Public Service	Gas & Electric	2009-2012	Customers	D-6690-UR-119
WI	Wisconsin Public Service	Gas & Electric	2013	Not Applicable, plan only 1 year in duration	Docket 6690-UR-121
WY	Questar Gas	Gas	2009-2012	Customers	Docket 30010-94-GR-08

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
Canada					
BC	BC Gas	Gas	1994-1995	Hybrid	Order G-59-94
BC	BC Gas	Gas	1996-1997	Hybrid	N/A
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Hydro	Electric	2009-2010	Hybrid	Order G-16-09
BC	BC Hydro	Electric	2011	Not Applicable, plan only 1 year in duration	Order G-180-10
BC	BC Hydro	Electric	2012-2014	Stairstep	Order G-77-12A
BC	FortisBC	Electric	2012-2013	Stairstep	Order G 110-12
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	Terasen Gas	Gas	2010-2011	Hybrid	Order G-141-09
BC	Terasen Gas	Gas	2012-2013	Stairstep	Order G-44-12
ON	Enbridge Gas Distribution	Gas	2008-2012	Revenue per Customer Indexing	Docket EB-2007-0615
ON	Union Gas	Gas	2008-2012	Indexing	Docket EB-2007-0606

Fixed/variable pricing relaxes the revenue/usage link with low administrative cost since it requires neither decoupling true ups nor load impact calculations. When average use is declining, base revenue will grow more rapidly with fixed/variable pricing so that rate cases tend to be less frequent even if the decline is largely driven by external forces. Base revenue grows more slowly than under conventional rate designs if average use is rising. The short term disincentive is removed to embrace various DSM initiatives. However, fixed/variable pricing reduces a utility's ability to use usage charges as a tool for promoting DSM. For example, it does not encourage customers with electric vehicles to charge these vehicles at night. Note also that the principle of rate design gradualism often discourages regulators from immediately adopting SFV pricing.

SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed/variable pricing in retail ratemaking are listed below on Table 5 and Figure 6. It can be seen that fixed/variable pricing has to date been considerably more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced, and the fact that the decline has been driven largely by external forces. Since our 2013 survey, fixed/variable pricing has been implemented for an electric utility in Oklahoma.

In addition to the precedents listed here, utilities in Wisconsin and several other states have in recent years made sizable steps in the direction of fixed/variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than are utilities in the United States. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 6: Fixed/Variable Pricing Precedents by State

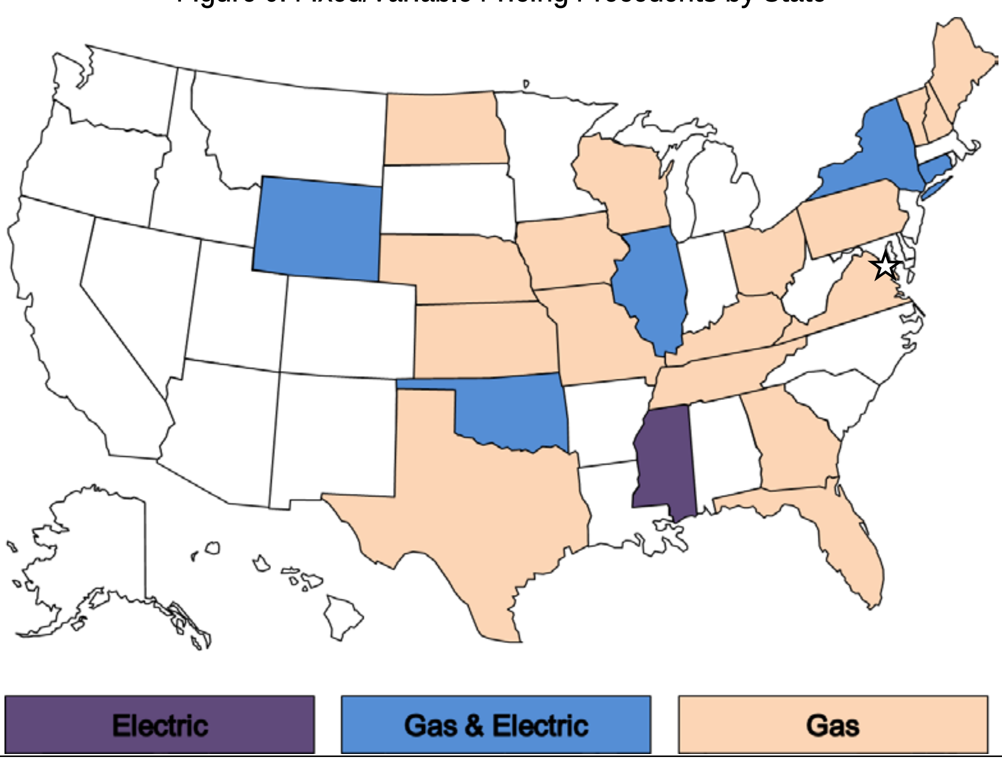


Table 5

Fixed Variable Residential Pricing Precedents[1]

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
CT	Connecticut Natural Gas	Gas	2014-open	Docket 13-06-08
CT	United Illuminating	Electric	Occurred over period of years	No specific case
CT	Yankee Gas System	Gas	2011-open	Docket 10-12-02
FL	Peoples Gas System	Gas	2009-open	Docket 080318-GU
GA	Liberty Utilities	Gas	2015-open	Docket 34734
IA	Black Hills Energy	Gas	2009-open	Docket RPU-08-3
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Ameren Illinois	Gas	2012-open	Case 11-0282
IL	Ameren Illinois	Electric	Occurred over period of years	No specific case
IL	Commonwealth Edison	Electric	2011-2013	Case 10-0467
IL	Mt. Carmel Public Utilities	Gas	2013-open	Case 13-0079
IL	North Shore Gas	Gas	2008-open	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	Case 07-0242
KS	Atmos Energy	Gas	2010-open	Docket 10-ATMG-495-RTS
KS	Black Hills Energy (formerly Aquila)	Gas	2007-open	Docket 07-AQLG-431-RTS
KS	Kansas Gas Service	Gas	2012-open	Docket 12-KGSG-835-RTS
KY	Atmos Energy	Gas	2014-open	Case 2013-00148
KY	Columbia Gas	Gas	2013-open	Case 2013-00167
KY	Delta Natural Gas	Gas	2007-open	Case 2007-00089
KY	Duke Energy Kentucky	Gas	2010-open	Case 2009-00202
ME	Maine Natural Gas	Gas	Occurred over period of years	Docket 2009-00067
ME	Northern Utilities	Gas	2014-open	Docket 2013-00133
MO	AmerenUE	Gas	2007-open	Case GR-2007-0003
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
NE	SourceGas Distribution	Gas	2012-open	Docket NG-0067
NH	Liberty Utilities (EnergyNorth Natural Gas)	Gas	Occurred over period of years	No specific case
NH	Northern Utilities	Gas	2014-open	DG 13-086
NY	Central Hudson Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
NY	Consolidated Edison	Electric & Gas	Occurred over period of years	No specific case
NY	Corning Gas	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - Long Island	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - New York	Gas	Occurred over period of years	No specific case
NY	National Fuel Gas	Gas	Occurred over period of years	No specific case

Table 5 (cont'd)

Jurisdiction	Company Name	Services	Years in Place	Case Reference
NY	New York State Electric & Gas	Electric	Occurred over period of years	No specific case
NY	Niagara Mohawk	Electric & Gas	Occurred over period of years	No specific case
NY	Orange & Rockland	Electric & Gas	Occurred over period of years	No specific case
NY	Rochester Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Arkansas Oklahoma Gas	Gas	2013-open	Cause PUD 201200236
OK	Centerpoint Energy	Gas	2010-open	Cause PUD 201000030
OK	Oklahoma Natural Gas	Gas	2004-open	Causes PUD 200400610, PUD 201000048, PUD 200900110
OK	Public Service Company of Oklahoma	Electric	2015-open	Cause PUD 201300217
PA	Columbia Gas	Gas	2013-open	Docket R-2012-2321748
TN	Atmos Energy	Gas	2012-open	Docket 12-00064
TN	Piedmont Natural Gas	Gas	2012-open	Docket 11-00144
TX	Atmos Energy - Mid-Tex Division	Gas	Occurred over period of years	No specific case
TX	Atmos Energy - West Texas Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Houston Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Beaumont/East Texas Division	Gas	Occurred over period of years	No specific case
VA	Columbia Gas of Virginia	Gas	Occurred over period of years	No specific case
VT	Vermont Gas Systems	Gas	Occurred over period of years	No specific case
WI	Madison Gas & Electric	Gas	2015-open	Docket 3270-UR-120
WI	Wisconsin Public Service	Gas	2015-open	Docket 6690-UR-123
WY	SourceGas Distribution	Gas	2011-open	Docket 30022-148-GR-10
WY	PacifiCorp (d/b/a Rocky Mountain Power)	Electric	2009-open	Docket 20000-333-ER-08

[1] Fixed variable pricing precedents include power and gas distributors that have a customer charge equal to or in excess of $15 (or $20 for vertically integrated electric utilities).

IV. Forward Test Years

General rate cases involve "test years" in which revenue requirements and billing determinants (e.g., the residential delivery volume) are jointly considered in ratesetting. A historical test year ends before the rate case is filed. A forward (a/k/a "fully forecasted") test year ("FTY") begins after the rate case is filed. An FTY typically begins about the time the rate case is expected to end and new rates take effect. Two-year forecasts may be required in this event which span both the year of the rate case and the rate effective year.[4] In between forward and historical test years is the option of a "partially forecasted" test year in which some months of historical data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historical test years tend to be uncompensatory when cost is growing faster than billing determinants. Annual rate cases with historical test years can alleviate but not eliminate underearning under these conditions. The effect on credit metrics can be material. [5] Where historical test years are used, there are thus added advantages to implementing other Altreg innovations discussed in this survey.

Forward test years can fully compensate utilities when cost growth exceeds growth in billing determinants. If this imbalance is chronic, however, FTYs do not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, such as cost trackers or multiyear rate plans.

Many approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalize data for an historical reference period, adjusted for known and measurable changes, and then use indexing and other statistical methods to extend projections. A mixture of forecasting methods is common. For example, index-based forecasting may be used only for O&M expenses.

FTYs were adopted in many jurisdictions during the 1970s and 1980s, when rapid inflation and major plant additions coincided with oil shock-induced slowdowns in the growth of average use. Several additional states have recently moved in the direction of FTYs. Some of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure.

Current state policies concerning test years are summarized below in Figure 7 and Table 6. In many jurisdictions the use of partially or fully-forecasted test years is not standardized. For example, in some jurisdictions, including Illinois and North Dakota, utilities are allowed to select their type of rate case test year. Test year selection may also be made part of the rate case (e.g., Utah). A few jurisdictions allow forward test years to be used in rate cases or formula rate plans, but not both (e.g., Illinois and Arkansas).

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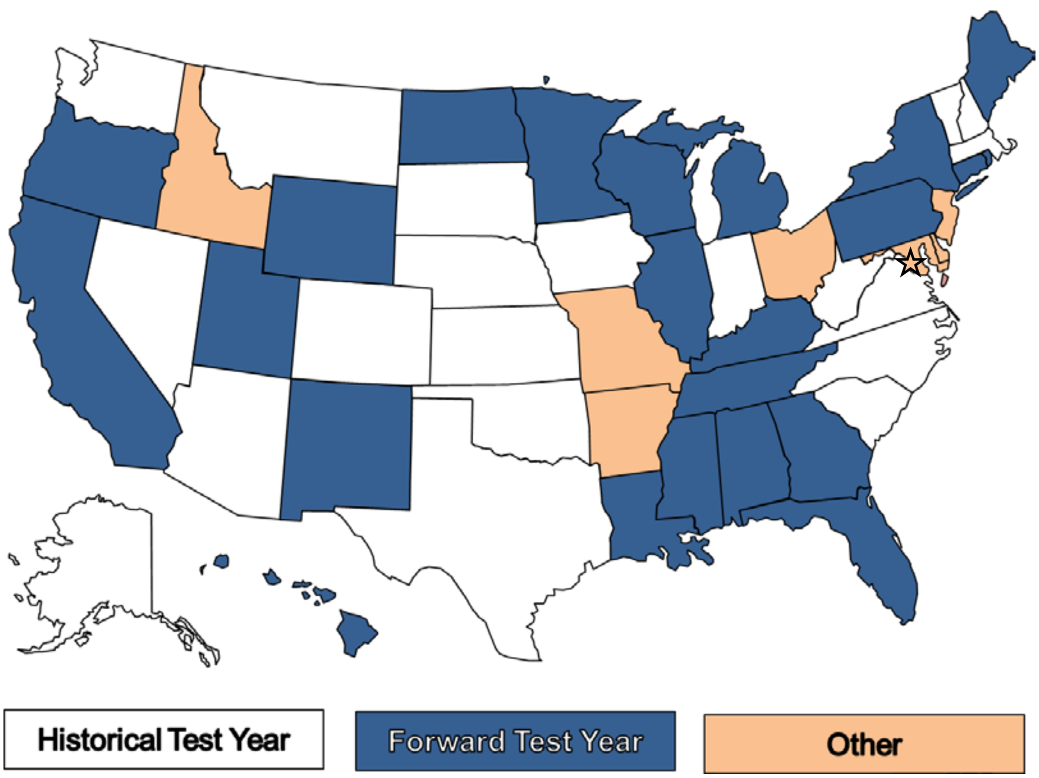
[4] A forward test year can in principle be the rate case year, and thereby not require two-year forecasts. Proposed rates can be established on an interim basis shortly after the filing.

[5] For evidence see "Forward Test Years for US Electric Utilities" by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, Edison Electric Institute, 2010.

Because of these complications, we have separated Table 6 into separate sections, specifying where FTYs are commonly used or occasionally used. Figure 7 shows jurisdictions where FTYs are commonly or occasionally used. Jurisdictions where partially-forecasted test years are commonly or occasionally used are in the category titled Other, with the remaining jurisdictions counted as historical test years.

The ranks of US jurisdictions that allow the use of forward test years have swollen and now encompass about half of the total. Since our 2013 survey, electric utilities in Pennsylvania have successfully used FTYs and utilities in Arkansas and Indiana have received legislative authorization for their use.[6][7] Forward test years are the norm in Canadian regulation.

Figure 7: Test Year Policy by State



[6] In addition, another electric utility in Mississippi was recently permitted to use a forward-looking formula rate plan.
[7] FTYs in Arkansas can only be used in formula rate plans.

Table 6

Test Year Approaches of US Jurisdictions

Jurisdiction	Notes
Fully-Forecasted Test Years Commonly Used (15)	
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	
FERC	Rate cases use forward test years but some formula rate plans use historical test years
Florida	
Georgia	
Hawaii	
Maine	
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	
Tennessee	
Wisconsin	
Fully-Forecasted Test Years Occasionally Used (9)	
Illinois	Utilities use various test years including forward test years ("FTYs")
Kentucky	Utilities use various test years including FTYs
Louisiana	Utilities use various test years including FTYs
Mississippi	Both electric utilities operate under forward-looking formula rate plans. Gas formula rate plans rely on historical test years ("HTYs").
New Mexico	A recently passed law allows for use of FTYs, and at least one rate increase based on FTY evidence has been approved
North Dakota	Utilities use various test years including FTYs
Pennsylvania	Partially-forecasted test years have traditionally been the norm. However, a law allowing fully-forecasted test years passed in 2012 and several electric utility rate increases based on FTY evidence have been approved.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently used FTYs
Partially-Forecasted Test Years Commonly or Occasionally Used (8)	
Arkansas	Utilities have typically used partially forecasted test years in rate cases. However, a recent bill authorized the use of formula rates with either historical or forecasted test periods.
Delaware	Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Idaho	
Maryland	Utilities use various test years excluding FTYs
Missouri	Utilities have the option to file partially-forecasted test years
New Jersey	
Ohio	
Historical Test Years Commonly Used (20)	
Alaska	
Arizona	
Colorado	Utilities have filed FTY evidence. However, no FTY rates have yet been approved but a recent case made extraordinary HTY adjustments.
Indiana	A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has been approved for an energy utility to date
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

V. Multiyear Rate Plans

Multiyear rate plans ("MRPs") are designed to reduce regulatory cost, while increasing the utility incentive for efficient operation. Rate cases are held infrequently, most often at three to five year intervals. Between rate cases, rate escalations are based on a combination of automatic attrition relief mechanisms ("ARMs") and cost trackers. The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth.

The "externalization" of ratemaking that ARMs and rate case moratoria achieve gives utilities more opportunity to profit from improved performance. Benefits of better performance can be shared between the utility and its customers. Performance incentives are strengthened despite streamlined regulation. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs can cap growth in rates (e.g., customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster customer use of the grid. Revenue caps are usually combined with revenue decoupling mechanisms, and are often favored where utilities must cope with declining average use and/or policymakers strongly encourage DSM.

Several approaches to ARM design are well-established. These include multiyear cost forecasts, indexing, and hybrids. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in other cost drivers like the number of customers served. A hybrid approach to ARM design was developed in the US that involves indexing of revenue for O&M expenses and forecasts for capital cost revenue.

The indexing approach to ARM design has been more common for UDCs because their cost growth is relatively gradual and predictable. Hybrid and forecasted ARMs have historically been more common for vertically integrated electric utilities because occasional major plant additions have given their cost trajectories more of a "stairstep" pattern. However, this pattern is becoming less common in an era when demand growth is slower and fewer large power plants are under construction. Some VIEUs operating under MRPs have separate ARMs for generation and distribution.

Cost trackers are often used in MRPs to address changes in business conditions that are difficult to address using ARMs. A tracker that recovers a large portion of a utility's capex cost can sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. MRPs with "tracker/freeze" provisions for vertically integrated utilities often accord tracker treatment to costs of new or refurbished generating plants.[8] Trackers also address *force majeure* events like severe storms and changes in tax rates that affect costs.

Many MRPs feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some MRPs feature "off-ramps" that permit plan suspension when earnings are unusually high or low.

[8] A good example is the Generation Base Rate Adjustment in the current MRP of Florida Power & Light.

Plans often feature performance incentive mechanisms that are linked to the utility's service quality. With stronger cost containment incentives, there is a greater need for a link between revenue and service quality. Many MRPs combine revenue decoupling, the tracking of DSM expenses, and performance incentives for DSM. The stronger incentive to contain cost that MRPs provide then becomes a "fourth leg" for the DSM stool.

MRPs have long been used to regulate utilities where market-responsive rates and services are a priority. Infrequent rate cases reduce the regulatory cost of allocating the revenue requirement between a complex and changing mix of market offerings and lessen concerns about cross-subsidization. These benefits of MRPs can be enhanced by designing other plan provisions in ways that insulate core customers from potentially adverse consequences of marketing flexibility.

For example, in the early 1990s, Maine's electric utilities were still vertically integrated and needed flexibility in marketing power to paper and pulp customers, some of whom had cogeneration options. The commission, under the chairmanship of Thomas Welch (a former telecom industry lawyer) approved a succession of price cap plans for Central Maine Power which facilitated marketing flexibility. As a result, the company had more freedom to enter into special contracts. The stronger incentives the company had to offer the right discounts to customers at risk of bypass was acknowledged by the commission when costs were allocated in later rate cases.

MRPs were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies. A major attraction was the ability of MRPs to afford utilities flexibility in serving markets with diverse competitive pressures and complex, changing customer needs. US and Canadian precedents for MRPs in the electricity and gas utility industries are indicated in Table 7 and Figures 8a and 8b.[9] In the US, MRPs have traditionally been most common in California and the Northeast. MRPs have been adopted by well-known VIEUs in Florida, North Dakota, and Virginia since our 2012 survey. A number of states have, additionally, experimented with "mini-MRPs" with terms of only two years. The forecast and tracker/freeze approaches to ARM design are most common currently in the US. The Federal Energy Regulatory Commission ("FERC") uses MRPs with index-based ARMs to regulate oil pipelines.

Canada is moving towards MRPs with index-based ARMs for gas and electric power distribution in all four populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Britain, and New Zealand are long time practitioners.

[9] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from Table 7 and Figures 8a and 8b.

Figure 8a: Recent US Multiyear Rate Plan Precedents by State

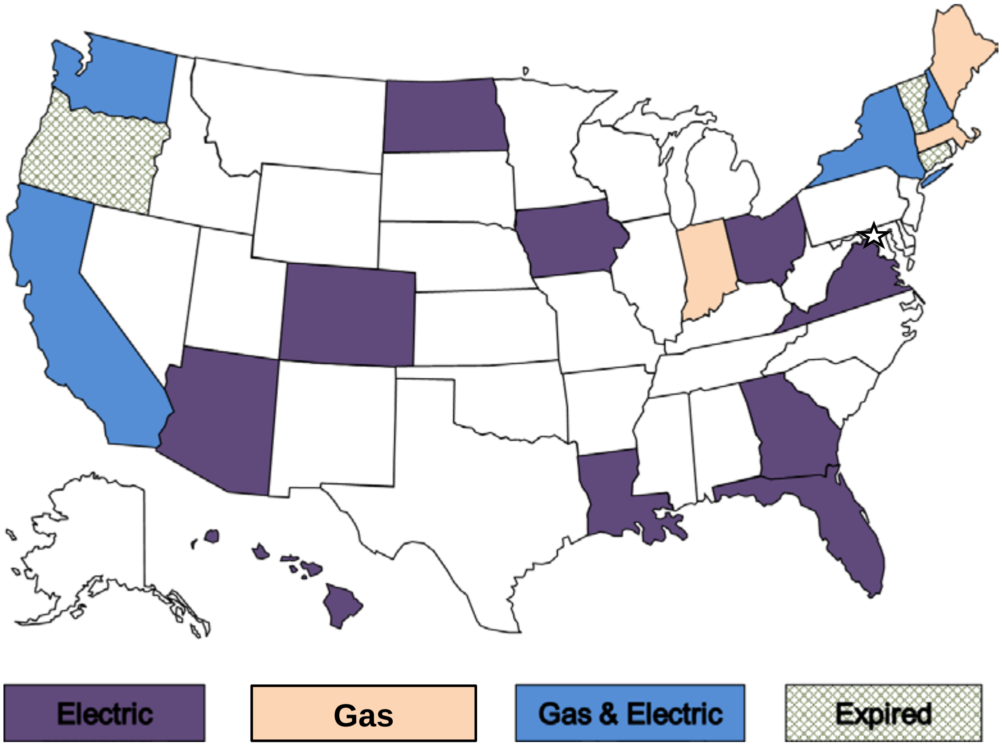


Figure 8b: Recent Canadian Multiyear Rate Plan Precedents by Province

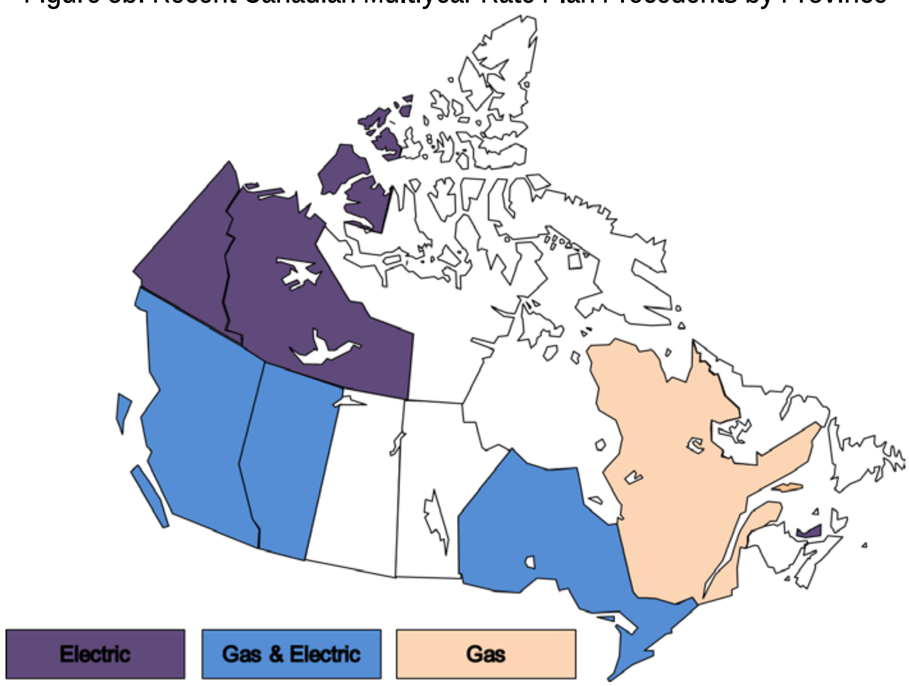


Table 7

Multiyear Rate Plan Precedents [1]

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current						
United States						
AZ	Arizona Public Service	2012-2016	Bundled power service	Rate Freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capital and other cost trackers, LRAM	None	Decision 73183; May 2012
CA	Bear Valley Electric Service	2013-2016	Power distribution	Revenue Cap Stairstep	None	Decision 14-11-002; November 2014
CA	California Pacific Electric	2013-2015	Power distribution	Revenue Cap Index	None	Decision 12-11-030; November 2012
CA	Pacific Gas & Electric	2014-2016	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 14-08-032; August 2014
CA	PacifiCorp	2011-2013, extended through 2016	Bundled power service	Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings	None	Decision 10-09-010; September 2010
CA	San Diego Gas & Electric	2012-2015	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southern California Gas	2012-2015	Gas	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southwest Gas	2014-2018	Gas	Revenue Cap Stairstep	None	Decision 14-06-028; June 2014
CO	Public Service of Colorado	2015-2017	Bundled power service	Rate Freeze with multiple capital cost trackers	Sharing of overearnings only up to earnings cap	Decision C15-0292; March 2014
FL	Florida Power & Light	2013-2016	Bundled power service	Rate Freeze with multiple capital and other cost trackers	None	Docket 120015-EI; December 2012
FL	Gulf Power	2014-June 2017	Bundled power service	Price Cap Stairstep through 2015, Rate Freeze beyond	None	Docket 130140-EI; December 2013
FL	Duke Energy Florida (formerly Progress Energy Florida)	2012-2016, extended through 2018	Bundled power service	Rate Freeze with one step plus capital and other cost trackers	None	Dockets 120022-EI and 130208-EI; 2012 and November 2013
FL	Tampa Electric	2013-2017	Bundled power service	Revenue Cap Stairstep	None	Docket 130040-EI
GA	Georgia Power	2014-2016	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with deadband	Docket 36989; December 2013
HI	Hawaiian Electric Company	2012-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2008-0083
HI	Hawaiian Electric Light Company	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0164
HI	Maui Electric	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0163
IA	MidAmerican Energy	2014-2017	Bundled power service	Revenue Cap Stairstep for 2014-2016, Rate Freeze for 2017	Sharing of overearnings only with deadband up to earnings cap	RPU-2013-0004
IN	Northern Indiana Public Service Company	2015-2020	Gas	Rate Freeze with capital and other cost trackers, possible reopening in 2017	Earnings cap implemented if company overearns since last rate case or prior 59 months, whichever is less	Cause 43894 and 44403 TDSIC 1 (August 2013 and January 2015)
LA	Cleco Power	2014-2017	Bundled power service	Rate Freeze with capital and other cost trackers	Sharing of overearnings only with deadband up to earnings cap	Docket U-32779; June 2014
MA	Bay State Gas	2015-2018	Gas	Revenue Cap Stairstep for 2015, 2016, Revenue Freeze through October 2018	None	DPU 15-150; October 2015
ME	Summit Natural Gas of Maine	2013-2022	Gas	Price Cap Indexing: 75% of change in GDPPI	None until company has 1,000 or more customers, then sharing of under/overearnings evenly with deadband	Docket 2012-258; January 2013
NH	Northern Utilities	May 2014 - April 2017	Gas	Revenue Cap Stairstep for 2014-2015, Rate Freeze in 2016	Sharing of overearnings only with deadband up to earning cap	DG 13-086; April 2014
NH	Public Service Company of New Hampshire	2010-2015	Power distribution (generation regulated separately)	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013	Sharing of overearnings only with deadband	DE 09-035
NH	Unitil Energy Systems	2011-2016	Power distribution	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013	Sharing of overearnings only with deadband	DE 10-055

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
United States (cont'd)						
NY	Central Hudson Gas & Electric	2015-2018	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	2014-2016	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 13-G-0031
NY	Corning Natural Gas	2012-2015	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-G-0280
NY	Orange & Rockland Utilities	November 2015-October 2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple sharing bands	Case 14-G-0494
ND	Northern States Power - Minnesota	2013-2016	Bundled power service	Revenue Cap Stairstep for 2013-2015, Rate Freeze in 2016	Sharing of overearnings only without deadband, earnings adjusted for effects of weather	Case PU-12-813
OH	First Energy Ohio	2011-2014, later extended to 2016	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Cases 11-388-EL-SSO, 12-1230-EL-SSO
US	All	2011-2016	Oil pipelines	Price Cap Index: PPI-Finished Goods + 2.65%	None	Docket RM10-25-000; December 2010
VA	Appalachian Power	2014-2017	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
VA	Virginia Electric Power	2015-2019	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
WA	Puget Sound Energy	2013-2016	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, equal sharing between company and customers	Dockets UE-121697 and UG-121705
Canada						
Alberta	Altagas Utilities and ATCO Gas	2013-2017	Gas	Revenue per Customer Indexing: Input price index - 1.16%, + capital cost trackers	None	Decision 2012-237
Alberta	ATCO Electric, EPCOR, Fortis Alberta	2013-2017	Power distribution	Price Cap Index: Input Price Index - 1.16%, + capital cost trackers	None	Decision 2012-237
British Columbia	FortisBC	2014-2018	Bundled power service	Revenue Cap Index: I-Factor - 1.03%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698719, Decision; September 2014
British Columbia	FortisBC Energy	2014-2018	Gas	Revenue Cap Index: I-Factor - 1.1%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698715, Decision; September 2014
Ontario	All unless company opts out	2014-2018	Power distribution	Price Cap Index: Input price index - (0%+stretch); stretch factor reassigned annually, + capital cost tracker option available	None	EB-2010-0379 Report of the Board; November 2013
Ontario	Horizon Utilities	2015-2019	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2014-0002; December 2014
Ontario	Hydro One Networks	2015-2017	Power distribution	Revenue Cap Stairstep	None	EB-2014-0247; March 2015
Ontario	Enbridge Gas Distribution	2014-2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2012-0459, Decision with Reasons; July 2014
Ontario	Union Gas Limited	2014-2018	Gas	Revenue Cap Index: 40% of growth in GDP-IPI	Sharing of overearnings only with deadband, multiple sharing ranges	EB 2013-0202 Decision; October 2013
Prince Edward Island	Maritime Electric	2013-2016	Bundled power service	Price Cap Stairstep: Bill defines rates for each year.	Earnings cap set at allowed ROE, no floor	Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act
Quebec	Gazifere	2011-2015	Gas distribution	Price Cap Index	Sharing of overearnings only without deadband and multiple sharing bands up to earnings cap	D-2010-112; August 2010
Yukon Territory	Yukon Electrical Company, Limited	2013-2015	Bundled power service	Revenue Cap Stairstep	None	Board Order 2014-06; April 2014

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Great Britain						
Great Britain	All	2013-2021	Gas and power transmission	British-Style Hybrid	Not reviewed	RIIO-T1 Final Proposals, April and December 2012
Great Britain	All	2013-2021	Gas distribution	British-Style Hybrid	Not reviewed	RIIO-GD1 Final Proposals, December 2013
Great Britain	All	2015-2023	Power distribution	British-Style Hybrid	Variances of cost from budgets shared though Information Quality Incentive Mechanism	RIIO-ED1 Final Proposals, December 2014
Australia/New Zealand						
Australia	ActewAGL	2015-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	Final Decision ActewAGL distribution determination 2015-16 to 2018-19; April 2015
Australia	Ausgrid	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ausgrid distribution determination 2015-16 to 2018-19; April 2015
Australia	Directlink	2015-2020	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision Directlink transmission determination 2015-16 to 2019-20; April 2015
Australia	Endeavour Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Endeavour Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Energex	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Energex determination 2015-16 to 2019-20
Australia	Ergon Energy	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ergon Energy determination 2015-16 to 2019-20
Australia	Essential Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Essential Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Jemena Gas Networks	2015-2020	Gas distribution	Australian-Style Hybrid	Not reviewed	Final Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2015−20; June 2015
Australia	SA Power Networks	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision SA Power Networks determination 2015-16 to 2019-20
Australia	TasNetworks	2015-2019	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TasNetworks transmission determination 2015-16 to 2018-19; April 2015
Australia	TransGrid	2015-2018	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TransGrid transmission determination 2015-16 to 2017-18; July 2015
Australia	Power & Water	2014-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	2014 Networks Price Determination Final Determination Part-A Statement of Reasons; April 2014
Australia	All Queensland Distributors	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for Qld Gas Network, Final Decision; June 2011
Australia	Energex and Ergon Energy	2010-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Queensland Distribution Determination 2011-11 to 2014-15 (Final Decision)
Australia	Envestra	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for the SA Gas Network, Final Decision; June 2011
Australia	All Victorian Distributors	2013-2017	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Final Decision; March 2013

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Australia/New Zealand (cont'd)						
Australia	CitiPower	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	CitiPower Pty Distribution Determination 2011-2015; September 2012
Australia	Powercor	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Powercor Australia Ltd Distribution Determination 2011-2015; October 2012
Australia	Jemena Electricity Networks	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Jemena Electricity Networks (Victoria) Ltd Distribution Determination 2011-2015; September 2012
Australia	SP AusNet	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	SPI Electricity Pty Ltd Distribution Determination 2011-2015; August 2013
Australia	United Energy Distribution	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	United Energy Distribution Distribution Determination 2011-2015; September 2012
New Zealand	All but Orion Electric	2015-2020	Power distribution	Revenue Cap Index: CPI-0% for most companies	None	Project no. 14.07/14118; November 2014
New Zealand	All	2013-2017	Gas distribution	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
New Zealand	All	2013-2017	Gas transmission	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
Historic						
United States						
CA	Bear Valley Electric Service	2009-2012	Power distribution	Revenue Cap Stairstep	None	Decision 09-10-028; October 2009
CA	Pacific Gas & Electric	2011-2013	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 11-05-018; May 2011
CA	Pacific Gas & Electric	2007-2010	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 07-03-044; March 2007
CA	Pacific Gas & Electric	2004-2006	Gas & bundled power service	Revenue Cap Index	None	Decision 04-05-055; May 2004
CA	Pacific Gas & Electric	1993-1995	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 92-12-057; December 1992
CA	Pacific Gas & Electric	1990-1992	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 89-12-057; December 1989
CA	Pacific Gas & Electric	1987-1989	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 86-12-092; December 1986
CA	Pacific Gas & Electric	1984-1986	Gas & bundled power service	Revenue Cap Hybrid	None	Decisions 83-12-068; December 1983 and 85-12-076; December 1985
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Price Cap Index	None	Decisions 06-12-011; December 2006 and 09-04-017; April 2009
CA	PacifiCorp	1994-1996	Bundled power service	Price Cap Index	None	Decision 93-12-106; December 1993
CA	PacifiCorp	1984-1987	Bundled power service	Revenue Cap Hybrid	None	Decisions 84-07-150; July 1984 and 85-12-076; December 1985
CA	San Diego Gas & Electric	2008-2011	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	San Diego Gas & Electric	2005-2007	Gas & bundled power service	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	San Diego Gas and Electric	1999-2002	Gas & power distribution	Price Cap Index	Sharing of overearnings only above deadband with multiple sharing bands	Decision 99-05-030; May 1999

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
CA	San Diego Gas & Electric	1994-1999	Gas & bundled power service	Revenue Cap Hybrid	Sharing of overearnings only with deadband and multiple sharing bands up to an earnings cap	Decision 94-08-023; August 1984
CA	San Diego Gas & Electric	1989-1993	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 88-12-085; December 1988
CA	San Diego Gas & Electric	1986-1988	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 85-12-108; December 1985
CA	Sierra Pacific Power	2009-2011, extended to 2012	Bundled power service	Price Cap Index	None	Decision 09-10-041; October 2009
CA	Sierra Pacific Power	1990-1992	Bundled power service	Revenue Cap Hybrid	None	Decision 90-07-060; July 1990
CA	Southern California Edison	2012-2014	Bundled power service	Revenue Cap Hybrid	None	Decision 12-11-051; November 2012
CA	Southern California Edison	2009-2011	Bundled power service	Revenue Cap Stairstep	None	Decision 09-03-025; March 2009
CA	Southern California Edison	2006-2008	Bundled power service	Revenue Cap Hybrid	None	Decision 06-05-016; May 2006
CA	Southern California Edison	2004-2006	Bundled power service	Revenue Cap Hybrid	None	Decision 04-07-022; July 2004
CA	Southern California Edison	1997-2001	Power distribution	Price Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 96-09-092; September 1996
CA	Southern California Edison	1986-1991	Bundled power service	Revenue Cap Hybrid	None	Decision 85-12-076; December 1985
CA	Southern California Gas	2008-2011	Gas	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	Southern California Gas	2005-2007	Gas	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	Southern California Gas	1998-2003	Gas	Revenue Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 97-07-054; July 1997
CA	Southern California Gas	1990-1993	Gas	Revenue Cap Hybrid	None	Decision 90-01-016; January 1990
CA	Southern California Gas	1985-1989	Gas	Revenue Cap Hybrid	None	1984, 85-12-076; December 1985, and 87-05-027; May 1987
CA	Southwest Gas	2009-2013	Gas	Revenue Cap Stairstep	None	Decision 08-11-048; November 2008
CO	Public Service Company of Colorado	2012-2014	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, multiple sharing bands up to earnings cap	Decision C12-0494
CT	Connecticut Light & Power	2004-2007	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 03-07-02
CT	United Illuminating	2006-2008	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 05-06-04
FL	Florida Power & Light	2006-2009	Bundled power service	Rate Freeze with exception for new generating facilities after they are in service and multiple capital and other cost trackers	None	Docket 050045-EI
FL	Progress Energy Florida	2006-2009	Bundled power service	Rate Freeze with 1 step to reflect generation brought in-service and multiple capital and other cost trackers	None	Docket 050078-EI
GA	Georgia Power	2011-2013	Bundled power service	Revenue Cap Stairstep: Rate increases permitted for DSM and major generation plant additions	Sharing of overearnings only with deadband	Docket 31958
IA	MidAmerican Energy	2001-2005, extended to 2013	Bundled power service	Rate Freeze with nuclear capital and other cost trackers	Sharing of overearnings only in multiple sharing bands, deadband not applicable due to no allowed ROE	Dockets RPU-01-3 and RPU-2012-0001
LA	Cleco Power	2009-2014	Bundled power service	Rate Freeze with capital cost tracker	Sharing of overearnings only with deadband up to earnings cap	Order U-30689
MA	Bay State Gas	2006-2015, terminated in 2009	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 05-27
MA	Berkshire Gas	February 2002-January 2012	Gas distribution	No adjustment until September 2004, then Price Cap Index	None	Docket D.T.E. 01-56

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
MA	Boston Gas (I)	1997-2001	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket D.P.U. 96-50-C (Phase I); May 1997
MA	Boston Gas (II)	2004-2013, Terminated in 2010	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Price Cap Index	Even sharing of earnings above/below deadband	Docket D.T.E. 04-79
MA	Nstar	2006-2012	Power distribution	Price Cap Index	Deadband with 50-50 sharing of over and underearnings	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas distribution	Price Cap Index	Even sharing of overearnings only. No allowed ROE established for company and no determination of a deadband.	Docket 970795; June 1998
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Price Cap Index	50/50 sharing around deadband	Docket 97-116; March 1998
ME	Central Maine Power (I)	1995-1999	Bundled power service	Price Cap Index	Even sharing of earnings above/below deadband	Docket 92-345 Phase II; January 1995
ME	Central Maine Power (II)	2001-2007	Power distribution	Price Cap Index	50-50 sharing below deadband	Docket 99-666; November 2000
ME	Central Maine Power (III)	2009-2013	Power distribution	Price Cap Index: GDPPI - 1%, separate capital cost tracker for AMI	50-50 sharing above 11% ROE	Docket 2007-215
ME	Maine Natural Gas	2010-2012	Gas	Revenue Cap Stairstep with steps conditioned on company earnings	None	Docket 2009-67
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	Case 90-G-0981, Opinion 91-21; October 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband and multiple sharing bands	Case 93-G-0941, Opinion 94-22; October 1994
NY	Central Hudson Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Case 09-E-0588
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Gas & power distribution	Price Cap Stairstep	Sharing of overearnings only with deadband, multiple sharing bands up to earnings cap	Case 05-E-0934 & Case 05-G-0935; July 2006
NY	Consolidated Edison	2010-2013	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-G-0795
NY	Consolidated Edison	2007-2010	Gas	Revenue Cap Stairstep	Even sharing of overearnings only above deadband, sharing threshold adjustable depending on work with DSM program administrator for first year only	Case 06-G-1332
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Even sharing of overeearnings only above deadband	Case 93-G-0996, Opinion 94-2; October 1994
NY	Consolidated Edison	2010-2013	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 09-E-0428
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Price Cap Stairstep	Sharing of overearnings only with multiple bands. No allowed ROE approved.	Case 04-E-0572; March 2005
NY	Consolidated Edison	1992-1995	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings with varying allowed ROE and no deadband	Opinion 92-8
NY	Keyspan Energy Delivery - Long Island	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1185
NY	Keyspan Energy Delivery - New York	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1186
NY	Long Island Lighting Company	December 1, 1993- November 30, 1996	Gas	Revenue Cap Stairstep	Even sharing of overearnings only with deadband	Case 93-G-002, Opinion 93-23; December 1993
NY	Long Island Lighting Company	1992-1994	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only without deadband	Opinion 92-8

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
NY	New York State Electric & Gas	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0715
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with annually varying deadbands	Case 94-M-0349, Opinion 95-27; September 1995
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas & bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only above deadband	Case 92-G-1086, Opinion 93-22; November 1993
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband up to earnings cap	Case 29327, Opinion 89-37; June 1991
NY	Orange & Rockland Utilities	2009-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 08-G-1398
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Price Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 05-G-1494; October 2006
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Price Cap Stairstep	Even sharing of overearnings only without deadband	Case 02-G-1553; October 2003
NY	Orange & Rockland Utilities	2012-2015	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-E-0408
NY	Orange & Rockland Utilities	2008-2011	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 07-E-0949
NY	Orange & Rockland Utilities	1991-1993	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings above deadband	Case 89-E-175
NY	Rochester Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0717
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas & bundled power service	Revenue Cap Stairstep	Earnings cap only	Case 92-G-0741, Opinion No. 93-19; August 1993
OH	AEP-Ohio	2012-2015	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Case No. 11-346-EL-SSO; August 2012
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Price Cap Stairstep	Company subject to Significantly Excessive Earnings Test conducted annually	Case 08-920-EL-SSO
OR	PacifiCorp	1998-2001	Power distribution	Revenue Cap Index	Sharing of over/underearning outside deadband in multiple sharing bands	Order No. 98-191
US	All	2006-2011	Oil pipelines	Price Cap Index: PPI-Finished Goods + 1.3%	None	RM05-22-000
US	All	2001-2006	Oil pipelines	Price Cap Index: PPI-Finished Goods + 0%	None	RM00-11-000
US	All	1995-2001	Oil pipelines	Price Cap Index: PPI-Finished Goods - 1%	None	RM93-11-000
VT	Green Mountain Power	2007-2010	Bundled power service	Revenue Cap Stairstep	Earnings cap for overearnings above deadband; Multiple sharing bands for earnings apply if actual ROE below deadband (earnings floor of the deadband also applies)	Docket No. 7176
WA	Puget Sound Energy	1997-2001	Bundled power service	Price Cap Stairstep	None	Docket UE-960195
Australia/New Zealand						
Australia	Jemena Gas Networks	2010-2015	Gas distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement Proposal for NSW Gas Networks, Final Decision; June 2010
Australia	All New South Wales distributors	2009-2014	Power distribution	Australia-Style Hybrid	Not reviewed	New South Wales Distribution Determination 2009-10 to 2013-14 Final Decision
Australia	ElectraNet	2008-2013	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; April 2008
Australia	ElectraNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1094
Australia	Powerlink	2007-2012	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; June 2007

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
Australia	Powerlink	2002-2007	Power transmission	Australia-Style Hybrid	Not reviewed	File No: 2000/659
Australia	Snowy Mountains	1999-2004 (terminated in 2002 due to merger with Transgrid)	Electric transmission	Australia-Style Hybrid	Not reviewed	File No: C1999/62
Australia	SPI PowerNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1093
Australia	Transend	2009-2014	Power transmission	Australia-Style Hybrid	Not reviewed	Transend Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transend	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1100
Australia	Transgrid	2009-2014	Electric transmission	Australia-Style Hybrid	Not reviewed	Transgrid Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transgrid	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No. M2003/287
Australia	Transgrid	1999-2004	Power transmission	Australia-Style Hybrid	Not reviewed	File No: CG98/118
Australia- New South Wales	Country Energy Gas	2006-2010	Gas distribution	Australia-Style Hybrid	Not reviewed	Revised Access Arrangement for Country Energy Gas Network, Final Decision; November 2005
Australia- New South Wales	AGL Gas Networks	1999-2004	Gas transmission & distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement for AGL Gas Networks Limited, Final Decision; July 2000
Australia - New South Wales	All	2004-2009	Power distribution	Australia-Style Hybrid	Not reviewed	File No: S2004/138
Australia - New South Wales	All	1999-2004	Power distribution	Australia-Style Hybrid	Not reviewed	NEC Determination 99-1
Australia - Northern Territory	Power & Water	2000-2003	Power transmission & distribution	Australia-Style Hybrid	Not reviewed	Revenue Determinations document; June 2000
Australia - Northern Territory	Power & Water	2009-2014	Power transmission & distribution	Price Cap Index: CPI + 0.85%	Not reviewed	Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009
Australia - Northern Territory	Power & Water	2004-2009	Power transmission & distribution	Price Cap Index: CPI - 2%	Not reviewed	Final Determination Networks Pricing: 2004 Regulatory Reset; February 2004
Australia -Victoria	All	2008-2012	Gas distribution	Australia-Style Hybrid	Not reviewed	Gas Access Arragement Review 2008-2012, Final Decision; March 2008
Australia -Victoria	All	2003-2007	Gas distribution	Australia-Style Hybrid	Not reviewed	Review of Gas Access Arrangements, Final Decision; October 2002
Australia -Victoria	All	2006-2010	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Review 2006-2010 (Final Decision Volume 1)
Australia -Victoria	All	2001-2005	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Determination 2001-2005 (Final Decision Volume 1)
New Zealand	All	2010-2015	Power distribution	Revenue Cap Index: CPI - 0%	None	Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
New Zealand	All	2004-2009	Power distribution	Revenue Cap Index: CPI - 0.86% (Average across firms)	None	Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003
Canada						
Alberta	Enmax	2007-2013	Power distribution	Price Cap Index: Input Price Index -1.2%	50-50 for excess earnings above deadband	Decision 2009-035
Alberta	Northwestern Utilities	1999-2002, reopened for 2001-2002	Gas distribution	Revenue Cap Stairstep; at reopener replaced with rate freeze	Sharing of earnings above/below deadband with multiple bands for overearnings; at reopener simplified to 50/50 sharing of overearnings with deadband	Decision U98060; March 1998 and Decision 2000-85; December 2000
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Price Cap Index	None	City of Edmonton Distribution Tariff Bylaw 12367; August 2000
Northwest Territory	Northland Utilities	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 17-2011; November 2011
Northwest Territory	Northland Utilities (Yellowknife)	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 13-2011; August 2011
Ontario	All Ontario Distributors	2010-2013	Power distribution	Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	None	EB-2007-0673; July 2008, September 2008, and January 2009
Ontario	All Ontario Distributors	2006-2009	Power distribution	Price Cap Index	None	EB-2006-0089; December 2006
Ontario	All Ontario Distributors	2000-2003	Power distribution	Price Cap Index	50-50 sharing of excess earnings without deadband	RP-1999-0034; January 2000
Ontario	Enbridge Gas Distribution	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI * 53%	50-50 sharing of excess earnings above deadband	EB-2007-0615; February 2008
Ontario	Union Gas	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI -1.82%	Sharing of overearnings only with deadband and multiple sharing bands	EB-2007-0606; January 2008
Ontario	Union Gas	2001-2003	Gas distribution	Price Cap Index	50-50 sharing around deadband	RP-1999-0017; July 2001
Great Britain						
Great Britain	All	2008-2013	Gas distribution	British-Style Hybrid	Not reviewed	Review- Final Proposals; Published December 2007
Great Britain	All	2002-2007, extended to 2008	Gas distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2007-2012	Gas transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Great Britain	All	2002-2007	Gas transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	1998-2002	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1994-1997	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1992-1994	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
England & Wales	All	1995-2000	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2010-2015	Power distribution	British-Style Hybrid	Variances of cost from budgets shared though Information Quality Incentive Mechanism	Ofgem Distribution Price Control Review 5
Great Britain	All	2005-2010	Power distribution	British-Style Hybrid	Not reviewed	Ofgem Distribution Price Control Review 4

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Great Britain (cont'd)						
Great Britain	All	2000-2005	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	2001-2006, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	OECD Reviews of Regulatory Reform
England & Wales	National Grid	1997-2001	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	1993-1997	Power transmission	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.452
Great Britain	All	2007-2012	Power transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Scotland	All	2000-2005, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Scotland	All	1995-2000	Power transmission	British-Style Hybrid	Not reviewed	1995 Report by Monopolies and Mergers Commission

[1] Rate freezes without extensive supplemental funding from capital cost trackers are excluded from this table.

VI. Formula Rates

A cost of service formula rate plan ("FRP") is essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service. Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated. Regulatory cost is contained by limiting review of costs and revenues.

The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target. Both approaches can keep the utility whole for the time value of money.

Earning true up mechanisms often include a deadband in which variances don't trigger a rate adjustment. Once the variance exceeds the deadband, however, earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between the earnings true up mechanism of an FRP and the earnings *sharing* mechanisms found in some multiyear rate plans.

Formula rates do not always address major plant additions. In state-regulated FRPs for retail electric services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is often recovered through a separate tracker.

Mechanisms are sometimes added to an FRP to encourage better operating performance. For example, escalation of revenue that compensates the utility for its O&M expenses may be limited by a formula tied to an inflation index. FRPs in several states that include Illinois and Mississippi contain a number of targeted performance incentive mechanisms.

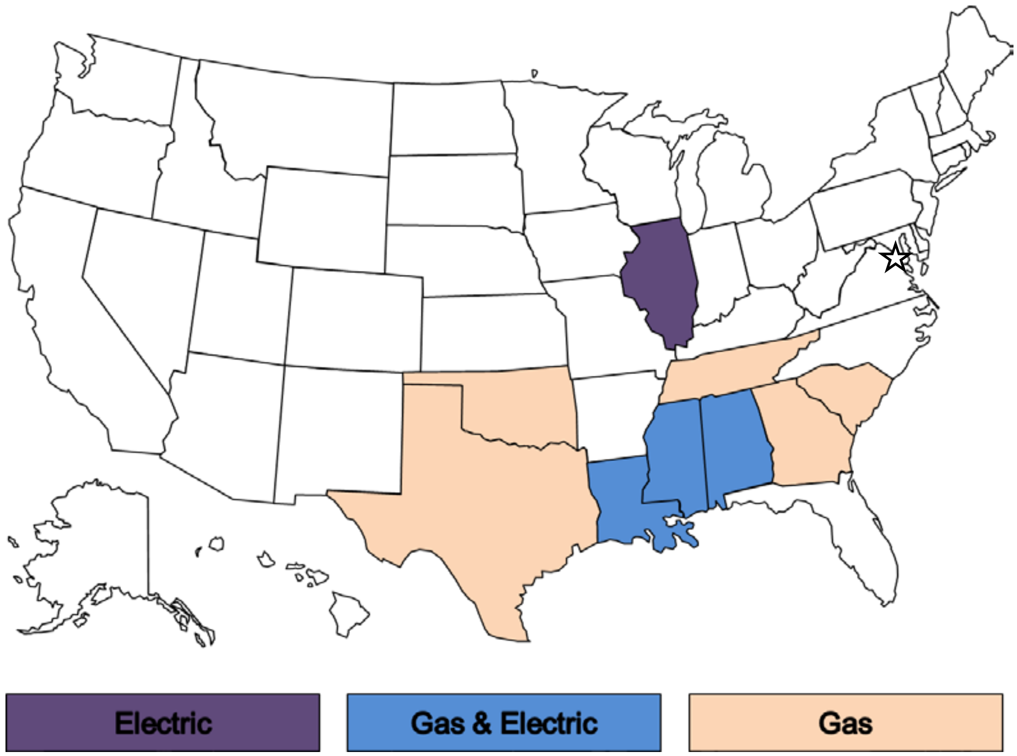
Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of energy utilities for decades. Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 8 and Figure 9.[10] It can be seen that FRPs for retail utility services are most common in the Southeast and South Central states. Alabama was an early innovator, approving "Rate Stabilization and Equalization"

[10] Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition. These usually take the form of ESMs that may or may not protect the utility from underearning.

plans for Alabama Power and Alabama Gas in the early 1980s.[11] Formula rates are now used to regulate electric utilities in Illinois, some gas and electric utilities in Louisiana and Mississippi, and some gas utilities in Georgia, Oklahoma, South Carolina, Tennessee, and Texas. Most of the recent approvals of formula rates have been for gas distribution, as this is one means to avoid the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized legislatively for electric utilities in Arkansas.

Figure 9: Current Retail Formula Rate Precedents by State



[11] For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 8

Retail Formula Rate Plan Precedents[1]

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Current					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2013-open	Dockets 18117 and 18416 (August 2013)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2014-2018	Dockets 18406 and 18328 (December 2013)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2013-2017	Docket 28101 (August 2013)
GA	Atmos Energy	Gas	Georgia Rate Adjustment Mechanism (GRAM)	2012-open	Docket 34764 (December 2011)
IL	Ameren Illinois	Power Distribution	Rate Modernization Action Plan - Pricing (Rate MAP-P)	2011-2017, extended through 2019	Case 12-0001 (September 2012) and Public Act 098-1175
IL	Commonwealth Edison	Power Distribution	Rate Delivery Service Pricing and Performance (Rate DSPP)	2011-2017, extended through 2019	Case 11-0721 (May 2012) and Public Act 098-1175
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Southwestern Electric Power	Electric	Formula Rate Plan	2013-2016	Docket U-32220 (July 2014)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2011-present	Docket 05-UN-0503 (April 2011)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2014-open	Docket 2014-UN-060 (May 2014)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 6 (FRP-6)	2015-open	Docket 2014-UN-132 (December 2014)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket 2003-UN-0898 (November 2009)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Cause PUD 201000030 (July 2010)
OK	Arkansas Oklahoma Gas	Gas	Performance Based Rate of Change Plan	2013-open	Cause PUD 201200236 (July 2013)
SC	Piedmont Gas	Gas	NA	2005-open	Docket 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas	NA	2005-open	Docket 2005-113-G (October 2005)
TN	Atmos Energy	Gas	Annual Review Mechanism	2015-open	Docket 14-00146 (May 2015)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2013-2017	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2007
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2014-open	Various Resolutions/Ordinances across cities in service territory including City of Tulia Ordinance 2014-03
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2012-open	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-2013	Dockets 18117 and 18416 (October 2005)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014, later changed to 2013	Dockets 18406 and 18328 (December 2007)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets 18046 and 18328 (June 2002)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1995	Dockets 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-2014	Docket U-21484 (May 2006)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket U-21484 (January 2001)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-2014	Dockets U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket UD-08-03 (April 2009)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket UD-01-04 (May 2003)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2009-2011	Docket 05-UN-0503 (December 2009)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2006-2009	Docket 05-UN-0503 (October 2005)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	1992-2006	Docket 92-UA-0230 (September 1992)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2012-2014	Docket 12-UN-139 (May 2012)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic (cont'd)					
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	2008-2012	Docket 07-UN-548 (December 2007)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	1996-2007	Docket 96-UN-0202 (September 1996)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP-5)	2010-2014	Docket 2009-UN-388 (March 2010)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 1 (FRP-1)	1995	Docket 93-UA-0301 (March 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket 06-UN-0511 (January 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Cause PUD U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Cause PUD 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Cause PUD 200400187 (November 2004)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2010-2014	Docket 200800348 (April 2009)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - varying end dates	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Centerpoint Energy - Beaumont East Texas Gas Division	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory

[1] Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

VII. Marketing Flexibility

This is a new section, added since the last survey. We've added it because we (and EEI) believe that marketing flexibility is a growing, strategic issue for EEI members. Several trends in business conditions are driving the need for more flexibility. The growth of distributed energy resources, for example, is a competitive challenge but also brings new service opportunities related to the development of distributed energy assets (e.g., designing, financing, procuring, building, fueling, and maintaining). Grid modernization is providing new functional capabilities to the grid which also create new service opportunities.[12] Examples include new reliability, network management, and transaction management services. Residential and commercial customers also have a growing interest in plug-in electric vehicles, and all retail customers have shown an interest in green power packages that can be supplied from grid-accessed resources.

New services will tend to be optional services that all customers will not want. Customers must be able to decline them; and if they do, not to incur associated costs. Competitive alternatives will be available for many of these services, and customers may have special needs that are difficult to address with standard tariffs. Thus, utilities will need to be able to respond quickly to the market. They will often be price "takers," as opposed to price "makers."

To date, regulatory precedent allowing investor-owned electric utilities to offer many of these services has been limited. This chapter is, in effect, a place holder for expected future electricity precedent.

Why Electric Utilities Need Marketing Flexibility

Of course, electric utilities have always needed flexibility in some of the markets they serve:

- Utility assets have uses in markets other than those for retail electric services. Most notably, surplus generating capacity of VIEUs can be used for sales in bulk power markets. These markets are competitive and price-volatile. Land in transmission corridors can be well-suited for nurseries. Prices utilities charge in competitive markets like these are largely decontrolled. Margins earned in these markets are shared with customers of retail electric services.
- The demand of large-load retail customers is often sensitive to the rates and other terms of service utilities offer because these customers have power-intensive technologies and/or options to cost-competitively cogenerate or operate at alternative locations, or are economically marginal. Customers of this kind are especially important to vertically integrated utilities. Discounts or special contracts for such customers are traditionally allowed but often require specific approval. Commission reviews of special contracts can take months.

[12] For an overview of modernization, see: EPRI, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, 2014.

Marketing Flexibility Remedies

Marketing flexibility runs the gamut from greater commission effort to approve new rates and services by traditional means to "light handed" regulation and outright decontrol. Light handed regulation typically takes the form of expedited approval of market offerings. These offerings may be subject to further scrutiny at a later date (e.g., in the next rate case).

Flexibility is most commonly granted for rates and services with certain characteristics. Light handed regulation of optional rates and services, for example, is based on the grounds that customers are protected by their freedom not to take the service, their continued access to service under standard tariffs, and the availability of alternatives in unregulated markets. Optional offerings include tariffs open to all qualifying customers, special contracts, and discretionary value-added services. Decontrol is typically permitted only for offerings to markets where vigorous competition reigns.

Marketing Flexibility Examples: Electric Utilities

Marketing flexibility is not extensive in the electric utility industry today but there are nonetheless notable examples such as the following.

- Four Florida electric utilities have "Commercial/Industrial Service Rider" ("CISR") tariffs that allow them to negotiate contract service agreements ("CSAs") that outline discounts on the base energy and/or demand charges for large load customers who can show that they have viable alternatives to utility-provided electric service.[13] The discounted rate must cover the incremental cost of service provision and provide a contribution to fixed costs. CSAs do not need commission approval but the commission has the option to conduct a prudence review of any signed contract.

- Duke Energy offers large North Carolina customers an optional Green Source Rider service. The program allows customers that have added at least 1 MW of new load since June 2012 to apply for an annual amount of renewable energy (and the associated renewable energy certificates) over a specific term (between 3-15 years). Customers may request a particular renewable resource in their application. Duke would then negotiate a purchased power agreement on behalf of the customer or attempt to source the energy from its own assets.

[13] Florida Public Service Commission (2014), Order Approving Commercial/Industrial Service Rider Tariff, Order No. PSC-14-0110-TRF-EI.

Marketing Flexibility in Other Regulated Industries

Regulators and electric utilities considering new forms of marketing flexibility can learn from other utility industries that have experienced technological change, increased competition, and/or complex and changing customer needs. We provide here brief overviews of experience in the telecommunications, gas distribution, gas transmission, and railroad industries.

Telecommunications

Local telephone companies (aka incumbent local exchange carriers or "ILECs") control the traditional distribution networks connecting residences and businesses. The "last mile" services they provide include the interconnection needed for long-distance, data, security, paging, and mobile telephone services as well as local telephone calling. ILECs have in the last 30 years confronted extensive competition, rapid technological change, and new marketing opportunities. Challenges they have faced have many parallels to those emerging for electric utilities.

The Federal Communications Commission (“FCC”) regulates interstate access services of ILECs. Other ILEC services are regulated by state commissions. In the 1980s, ILECs were still regulated using cost-of-service regulation with complex reporting and compensation schemes. This was succeeded by multiyear rate plans, often called "price cap" plans since they capped rate escalation but permitted some discounts to encourage greater system use. Price caps were often escalated using inflation – X formulas where the X factor reflected an estimate of the telecommunication industry productivity trend. Prices were separately capped for several baskets of services. This insulated customers in each service basket from discounts offered to other baskets. Insulation was heightened by the infrequency (or elimination) of rate cases and the common lack of earnings sharing. The FCC instituted price caps for interstate access services of ILECs in the early 1990s. Price caps also became commonplace in state ILEC regulation.

Marketing flexibility for ILECs has been most relevant in the following two areas.

<u>Competition in Traditional Service Markets</u> Some services ILECs offered became subject to mounting competitive pressure that varied with the location where service was offered. For example, by the late 1990s, competitive access providers like MFS were constructing high-speed fiber optic networks connecting office buildings in metropolitan areas. These networks allowed businesses and long-distance carriers to connect to customers while bypassing ILEC data facilities. They could also be used to transmit voice traffic, avoiding ILEC voice access charges. High regulated prices were uncompetitive in high-traffic locations where facilities-based competitors entered the market. For services subject to competitive challenges, price cap plans in many states permitted discounts to standard tariffs within certain bands (e.g., rates could rise by 5% less than the price cap index) and/or subject to pricing floors that discouraged predation and cross-subsidization. In markets where pronounced competition could be demonstrated, ILEC rates were sometimes effectively decontrolled.

<u>Innovative Services</u> Technological change gave rise to innovative new services [e.g., Voicemail, Centrex and high-speed data (e.g., digital subscriber loop or "DSL")] which utilize essential network assets of ILECs

and cannot not practically be performed by affiliates.[14] Many of these services were deemed "information" services and were regulated by the FCC. Regulators ultimately permitted ILECs to provide a host of these services and allowed considerable pricing flexibility.

Gas Distribution

Natural gas distributors also need flexibility to address some markets that they serve. Like VIEUs, many large-load customers of gas distributors have price sensitive demands and special needs. Distributors have frequently obtained light handed regulation to respond to these challenges. Nicor Gas, for example, offers a contract service for customers taking delivery near interstate gas pipelines. Contracts are submitted to state regulators for informational purposes and are treated on a proprietary basis. Nicor has similar flexibility to enter into custom contracts with electric power generators. The Company must document to the regulator that revenues from such service exceed the incremental cost of service, thereby ensuring a positive contribution to fixed cost recovery.

Interstate Gas Transmission

Interstate pipeline companies need marketing flexibility for many reasons. Demand for a pipeline's services can be sensitive to the terms it offers due to competition from other pipelines, dual-fuel capabilities of large volume customers, the extreme variability of need for service, and other special needs. It is difficult to design standard tariffs that meet the needs of all customers. Pipelines also have their own needs, such as an interest in signing anchor shippers to long-term contracts before constructing new facilities. Since 1996, the FERC has engaged in light handed regulation of negotiated pipeline rates to individual customers who have recourse to service under a standard tariff. The FERC gives a quick turnaround to most requests for negotiated contracts. A sizable share of pipeline service is conducted under negotiated rates. A remarkable variety of rate designs have been employed.[15]

Railroads

In the railroad industry, MRPs were permitted under the terms of the Staggers Railroad Act of 1980. Railroads were given a freer hand to respond to competition from truckers, waterborne carriers, and other railroads. The railroads also used marketing flexibility to offer discounts to customers that reduced their cost by assembling their own unit trains and not requesting pickups or deliveries in remote locations.

MRPs are less common today in the railroad and telecom industries. However, marketing flexibility continues under new regulatory systems that share with MRPs the attribute of protecting core customers without linking a carrier's rates closely to its own cost. Railroads have recently used this flexibility to compete for traffic from new oil field developments.

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[14] Centrex service, which provided businesses features like call-waiting, auto attendant, voicemail, 4-digit extension dialing and conference calling, could also be sourced by purchasing or leasing a private branch exchange ("PBX"), a private network platform that enabled these features.

[15] See, for example, Comments of the Interstate Natural Gas Association of America in FERC Docket PLO2-6-000, September 2002.

VIII. Conclusions

Regulation of North American energy utilities is evolving to better meet the needs of utilities and their customers in a rapidly changing world. Innovation continues, while some older forms of Altreg such as multiyear rate plans are having a renaissance.

The variety of Altreg approaches that have been established reflects the varied circumstances of utilities. Some are vertically integrated, while others are more specialized wire companies. Capex needs and trends in average use vary greatly. Regulatory traditions also vary across the US and other advanced industrial countries.

No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying challenges increases the chance that an approach has already been tried that would work well, with some adjustments, in new situations. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to achieve compensatory rates of return while making needed investments, improving efficiency, and developing more market-responsive rates and services. Regulation can be streamlined, and utilities can be encouraged to embrace cost-effective DERs. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which kinds of Altreg might work best in their situation.