Q. Please provide data and workpapers used to prepare JMC-1 through to JMC-10.

A. Please see Attachments B, C, E through I and K through N for data and workpapers used to prepare Exhibits JMC-1 through JMC-10. Attachments A, D and J can be found on Newfoundland Power's stranded website at the following link: https://ftp.nfpower.nf.ca/.

SNL Balance Sheets

ALLETE, Inc. | Balance Sheet

NYSE:ALE (MI KEY: 4022309; SPCIQ KEY: 289272)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	27,500	81,800	84,200	104,400	98,900
Gross Trade Accounts Receivable	106,500	125,200	122,500	138,800	112,600
Trade Accounts Receivable Allowance	3,100	2,400	2,400	2,100	2,100
Net Customer and Trade Accounts Receivable	103,400	122,800	120,100	136,700	110,500
Other Accounts Receivable	0	0	0	0	0
Accounts Receivable	103,400	122,800	120,100	136,700	110,500
Unbilled Revenue	19,100	NA	NA	NA	24,600
Current Inventories	104,200	110,500	103,400	102,600	95,900
Prepaid Expense	40,300	45,500	38,800	44,200	37,600
Current Investments	0	0	0	0	0
Short-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	NA	NA	NA	NA	NA
Current Assets	294,500	360,600	346,500	387,900	367,500
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	NA	NA	NA	NA	NA
Gas PP&E in Service, Gross	NA	NA	NA	NA	NA
Other PP&E in Service, Gross	NA	NA	NA	NA	NA
PP&E in Service, Gross	5,108,600	NA	NA	NA	5,235,700
Total Accumulated Depreciation	1,555,400	NA	NA	NA	1,684,800
Net PP&E in Service	3,553,200	3,745,300	3,745,600	3,746,300	3,550,900
Construction Work in Progress	188,000	NA	NA	NA	271,500
Net Nuclear Fuel	0	0	0	0	0

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	NA	NA	NA	NA	NA
Net PP&E	3,741,200	3,745,300	3,745,600	3,746,300	3,822,400
Other Assets ($000)					
Securities - Noncurrent	18,800	19,600	20,600	21,000	19,100
Nuclear Decommissioning Trust	0	0	0	0	0
Other Investments	36,800	38,100	35,600	34,800	34,000
Investment in Partnerships	135,600	140,200	143,100	146,000	118,700
Noncurrent Investments	191,200	197,900	199,300	201,800	171,800
Goodwill	131,200	131,200	131,400	149,900	148,300
Intangible Assets other than Goodwill	82,200	80,800	79,400	79,000	77,600
Total Intangible Assets	213,400	212,000	210,800	228,900	225,900
Long-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Noncurrent	NA	NA	NA	NA	NA
Regulatory Assets	330,100	320,900	324,500	310,600	384,700
Total Other Assets	106,500	105,200	104,800	103,000	107,700
Total Assets	4,876,900	4,941,900	4,931,500	4,978,500	5,080,000
Tangible Assets	4,663,500	4,729,900	4,720,700	4,749,600	4,854,100
Current Liabilities ($000)					
Short-term Debt	0	1,300	0	0	0
Current Portion of Long-term Debt	187,700	162,600	117,700	64,100	64,100
Short-term and Current Long-term Debt	187,700	163,900	117,700	64,100	64,100
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	17,600	14,800	17,500	14,600	17,600
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	5,400	NA	NA	NA	NA
Other Accounts Payable and Accrued Expense	120,500	115,300	100,100	127,100	186,300
Accounts Payable and Accrued Expense	143,500	130,100	117,600	141,700	203,900
Short-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Other Current Liabilities	68,300	70,600	70,100	84,700	83,200
Current Liabilities	399,500	364,600	305,400	290,500	351,200

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	210,900	195,100	195,800	195,200	191,800
Deferred Income Tax Liability	521,300	NA	NA	NA	197,700
Deferred Tax Credit	33,300	NA	NA	NA	32,800
Deferred Tax Liability	554,600	568,600	577,000	592,900	230,500
Non-current Long-term Debt	1,370,400	1,370,200	1,401,400	1,444,600	1,439,200
Long-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Regulatory Liabilities	125,800	125,000	125,800	111,500	532,000
Total Other Liabilities	322,700	316,900	309,100	301,100	267,100
Total Liabilities	2,983,900	2,940,400	2,914,500	2,935,800	3,011,800
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	1,893,000	2,001,500	2,017,000	2,042,700	2,068,200
Equity Attributable to Parent Company	1,893,000	2,001,500	2,017,000	2,042,700	2,068,200
Noncontrolling Interests	0	0	0	0	0
Total Equity	1,893,000	2,001,500	2,017,000	2,042,700	2,068,200
Tangible Common Equity	1,679,600	1,789,500	1,806,200	1,813,800	1,842,300
Tangible Equity	1,679,600	1,789,500	1,806,200	1,813,800	1,842,300
Capitalization ($000)					
Equity & Mezzanine Preferred	1,893,000	2,001,500	2,017,000	2,042,700	2,068,200
Total Debt	1,558,100	1,534,100	1,519,100	1,508,700	1,503,300

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Total Capitalization, at Book Value	3,451,100	3,535,600	3,536,100	3,551,400	3,571,500
Share Information					
Shares Issued	NA	NA	NA	NA	NA
Treasury Shares	NA	NA	NA	NA	NA
Common Shares Outstanding (actual)	49,560,000	50,883,123	50,956,836	51,039,658	51,117,000

S&P Global Market Intelligence uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, S&P Global Market Intelligence mines data from documents filed by the company, surveys, and other sources of public information.

Alliant Energy Corporation | Balance Sheet

NYSE:LNT (MI KEY: 4057038; SPCIQ KEY: 312949)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	8,200	8,400	7,300	9,200	27,900
Gross Trade Accounts Receivable	111,700	NA	NA	NA	103,300
Trade Accounts Receivable Allowance	8,700	NA	NA	NA	12,000
Net Customer and Trade Accounts Receivable	103,000	NA	NA	NA	91,300
Other Accounts Receivable	300,100	NA	NA	NA	306,400
Accounts Receivable	403,100	424,900	424,900	336,100	397,700
Unbilled Revenue	90,200	NA	NA	NA	85,100
Current Inventories	222,300	187,700	201,600	220,600	222,400
Prepaid Expense	0	0	0	0	0
Current Investments	0	0	0	0	0
Short-term Energy Risk-mgmt Assets	29,400	12,200	35,900	26,700	21,100
Deferred Taxes, Current	0	NA	NA	NA	0
Other Current Assets	123,900	116,600	145,000	158,900	150,900
Current Assets	877,100	749,800	814,700	751,500	905,100
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	11,043,500	NA	NA	NA	12,296,900
Gas PP&E in Service, Gross	1,107,600	NA	NA	NA	1,244,000
Other PP&E in Service, Gross	1,337,100	NA	NA	NA	1,344,600
PP&E in Service, Gross	13,488,200	NA	NA	NA	14,885,500
Total Accumulated Depreciation	4,454,200	NA	NA	NA	4,619,200
Net PP&E in Service	9,034,000	NA	NA	NA	10,266,300
Construction Work in Progress	1,226,800	NA	NA	NA	962,200
Net Nuclear Fuel	0	0	0	0	0

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	18,400	NA	NA	NA	6,000
Net PP&E	10,279,200	10,448,800	10,608,100	10,931,100	11,234,500
Other Assets ($000)					
Securities - Noncurrent	NA	NA	NA	NA	NA
Nuclear Decommissioning Trust	0	0	0	0	0
Other Investments	20,000	19,100	19,300	119,400	121,900
Investment in Partnerships	317,600	327,700	335,200	339,200	274,200
Noncurrent Investments	337,600	346,800	354,500	458,600	396,100
Goodwill	0	0	0	0	0
Intangible Assets other than Goodwill	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0
Long-term Energy Risk-mgmt Assets	12,000	1,100	2,000	2,700	4,000
Deferred Taxes, Noncurrent	NA	NA	NA	NA	NA
Regulatory Assets	1,857,300	1,904,600	1,947,500	1,952,300	1,582,400
Total Other Assets	10,600	13,800	16,600	18,700	65,700
Total Assets	13,373,800	13,464,900	13,743,400	14,114,900	14,187,800
Tangible Assets	13,373,800	13,464,900	13,743,400	14,114,900	14,187,800
Current Liabilities ($000)					
Short-term Debt	244,100	302,800	368,600	485,300	415,200
Current Portion of Long-term Debt	13,400	4,600	5,200	105,200	862,500
Short-term and Current Long-term Debt	257,500	307,400	373,800	590,500	1,277,700
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	NA	NA	NA	NA	NA
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	0	0	0	0	0
Other Accounts Payable and Accrued Expense	504,800	369,500	381,100	517,500	477,300
Accounts Payable and Accrued Expense	504,800	369,500	381,100	517,500	477,300
Short-term Energy Risk-mgmt Liabilities	13,300	13,400	17,800	18,500	18,700
Other Current Liabilities	386,400	474,700	435,500	343,600	375,300
Current Liabilities	1,162,000	1,165,000	1,208,200	1,470,100	2,149,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	489,900	481,700	482,700	481,300	504,000
Deferred Income Tax Liability	2,570,200	2,625,900	2,681,300	2,774,700	1,478,400
Deferred Tax Credit	NA	NA	NA	NA	NA
Deferred Tax Liability	NA	NA	NA	NA	NA
Non-current Long-term Debt	4,396,800	4,316,100	4,354,300	4,255,100	4,085,800
Long-term Energy Risk-mgmt Liabilities	15,300	31,900	27,600	26,600	23,000
Regulatory Liabilities	494,800	481,400	478,200	483,400	1,357,200
Total Other Liabilities	182,800	266,000	260,700	269,500	208,200
Total Liabilities	9,311,800	9,368,000	9,493,000	9,760,700	9,805,600
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	3,862,000	3,896,900	4,050,400	4,154,200	4,182,200
Equity Attributable to Parent Company	3,862,000	3,896,900	4,050,400	4,154,200	4,182,200
Noncontrolling Interests	200,000	200,000	200,000	200,000	200,000
Total Equity	4,062,000	4,096,900	4,250,400	4,354,200	4,382,200
Tangible Common Equity	3,862,000	3,896,900	4,050,400	4,154,200	4,182,200
Tangible Equity	4,062,000	4,096,900	4,250,400	4,354,200	4,382,200
Capitalization ($000)					
Equity & Mezzanine Preferred	4,062,000	4,096,900	4,250,400	4,354,200	4,382,200
Total Debt	4,654,300	4,623,500	4,728,100	4,845,600	5,363,500

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Total Capitalization, at Book Value	8,716,300	8,720,400	8,978,500	9,199,800	9,745,700
Share Information					
Shares Issued	227,673,654	227,823,278	231,062,417	231,204,360	231,348,646
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	227,673,654	227,823,278	231,062,417	231,204,360	231,348,646

S&P Global Market Intelligence uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, S&P Global Market Intelligence mines data from documents filed by the company, surveys, and other sources of public information.

American Electric Power Company, Inc. | Balance Sheet

NYSE:AEP (MI KEY: 4006321; SPCIQ KEY: 135470)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	***2017 FQ1***	***2017 FQ2***	***2017 FQ3***	***2017 FQ4***
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	210,500	175,000	172,400	343,900	214,600
Gross Trade Accounts Receivable	1,677,800	1,501,100	1,488,100	1,490,300	1,598,100
Trade Accounts Receivable Allowance	NA	NA	NA	NA	NA
Net Customer and Trade Accounts Receivable	NA	NA	NA	NA	NA
Other Accounts Receivable	80,200	66,500	51,600	63,300	62,700
Accounts Receivable	1,758,000	1,567,600	1,539,700	1,553,600	1,660,800
Unbilled Revenue	158,700	143,600	122,100	187,300	230,200
Current Inventories	967,300	955,300	982,200	916,500	953,200
Prepaid Expense	325,500	141,000	224,400	350,500	310,400
Current Investments	138,700	275,000	317,600	310,700	161,700
Short-term Energy Risk-mgmt Assets	94,500	85,000	165,700	141,900	123,700
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	2,380,700	273,900	284,900	263,400	598,500
Current Assets	6,033,900	3,616,400	3,809,000	4,067,800	4,253,100
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	55,408,400	56,301,700	57,202,400	58,114,100	59,601,500
Gas PP&E in Service, Gross	0	0	0	0	0
Other PP&E in Service, Gross	3,444,300	3,412,000	3,595,600	3,614,100	3,706,300
PP&E in Service, Gross	58,852,700	59,713,700	60,798,000	61,728,200	63,307,800
Total Accumulated Depreciation	16,397,300	16,674,200	16,907,600	17,121,700	17,167,000
Net PP&E in Service	42,455,400	43,039,500	43,890,400	44,606,500	46,140,800
Construction Work in Progress	3,183,900	3,196,800	3,336,800	3,710,000	4,120,700
Net Nuclear Fuel	NA	NA	NA	NA	NA

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	0	0	0	0	0
Net PP&E	45,639,300	46,236,300	47,227,200	48,316,500	50,261,500
Other Assets ($000)					
Securities - Noncurrent	0	0	0	0	0
Nuclear Decommissioning Trust	2,256,200	2,333,200	2,382,000	2,433,000	2,527,600
Other Investments	0	0	0	0	0
Investment in Partnerships	809,400	NA	NA	NA	812,300
Noncurrent Investments	3,065,600	2,333,200	2,382,000	2,433,000	3,339,900
Goodwill	52,500	52,500	52,500	52,500	52,500
Intangible Assets other than Goodwill	NA	NA	NA	NA	NA
Total Intangible Assets	NA	NA	NA	NA	NA
Long-term Energy Risk-mgmt Assets	289,100	310,500	285,600	310,400	282,100
Deferred Taxes, Noncurrent	NA	NA	NA	NA	NA
Regulatory Assets	5,625,500	5,583,100	5,592,600	5,640,000	3,587,600
Total Other Assets	2,761,800	3,596,300	3,390,200	3,144,700	2,952,400
Total Assets	63,467,700	61,728,300	62,739,100	63,964,900	64,729,100
Tangible Assets	NA	NA	NA	NA	NA
Current Liabilities ($000)					
Short-term Debt	1,713,000	1,536,000	1,851,700	1,059,300	1,638,600
Current Portion of Long-term Debt	2,941,400	2,514,200	2,755,000	2,359,300	1,812,700
Short-term and Current Long-term Debt	4,654,400	4,050,200	4,606,700	3,418,600	3,451,300
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	227,200	239,700	217,000	260,300	234,500
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	343,200	342,000	344,000	346,600	357,000
Other Accounts Payable and Accrued Expense	2,736,500	2,195,400	2,159,900	2,253,500	3,180,800
Accounts Payable and Accrued Expense	3,306,900	2,777,100	2,720,900	2,860,400	3,772,300
Short-term Energy Risk-mgmt Liabilities	53,400	68,200	60,200	68,000	61,600
Other Current Liabilities	1,483,300	1,019,000	1,004,400	975,000	986,100
Current Liabilities	9,498,000	7,914,500	8,392,200	7,322,000	8,271,300

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	614,100	586,200	462,800	468,900	398,100
Deferred Income Tax Liability	11,884,400	11,981,600	12,288,500	12,628,200	6,813,900
Deferred Tax Credit	NA	NA	NA	NA	NA
Deferred Tax Liability	NA	NA	NA	NA	NA
Non-current Long-term Debt	17,620,500	16,722,200	16,796,900	18,362,400	19,658,400
Long-term Energy Risk-mgmt Liabilities	314,800	342,900	310,600	352,700	313,400
Regulatory Liabilities	3,751,300	3,867,600	3,908,800	3,959,600	8,422,300
Total Other Liabilities	2,364,500	2,600,000	2,724,300	2,756,300	2,526,200
Total Liabilities	46,047,600	44,015,000	44,884,100	45,850,100	46,403,600
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	1,600	5,500	9,300	11,900
Total Mezzanine Level Items	0	1,600	5,500	9,300	11,900
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	17,397,000	17,687,100	17,824,100	18,069,100	18,287,000
Equity Attributable to Parent Company	17,397,000	17,687,100	17,824,100	18,069,100	18,287,000
Noncontrolling Interests	23,100	24,600	25,400	36,400	26,600
Total Equity	17,420,100	17,711,700	17,849,500	18,105,500	18,313,600
Tangible Common Equity	NA	NA	NA	NA	NA
Tangible Equity	NA	NA	NA	NA	NA
Capitalization ($000)					
Equity & Mezzanine Preferred	17,420,100	17,711,700	17,849,500	18,105,500	18,313,600
Total Debt	22,274,900	20,772,400	21,403,600	21,781,000	23,109,700

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Total Capitalization, at Book Value	39,695,000	38,485,700	39,258,600	39,895,800	41,435,200
Share Information					
Shares Issued	512,048,520	512,048,663	512,048,663	512,048,663	512,210,644
Treasury Shares	20,336,592	20,336,592	20,211,575	20,206,368	20,205,046
Common Shares Outstanding (actual)	491,711,928	491,712,071	491,837,088	491,842,295	492,005,598

S&P Global Market Intelligence uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, S&P Global Market Intelligence mines data from documents filed by the company, surveys, and other sources of public information.

Duke Energy Corporation | Balance Sheet

NYSE:DUK, BSP:DUKB34 (MI KEY: 4121470; SPCIQ KEY: 267850)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	***2017 FQ1***	***2017 FQ2***	***2017 FQ3***	***2017 FQ4***
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	392,000	878,000	298,000	282,000	358,000
Gross Trade Accounts Receivable	NA	NA	NA	NA	NA
Trade Accounts Receivable Allowance	NA	NA	NA	NA	NA
Net Customer and Trade Accounts Receivable	NA	NA	NA	NA	NA
Other Accounts Receivable	NA	NA	NA	NA	NA
Accounts Receivable	1,813,000	1,581,000	1,617,000	1,846,000	1,830,000
Unbilled Revenue	831,000	724,000	761,000	771,000	944,000
Current Inventories	3,522,000	3,366,000	3,369,000	3,265,000	3,250,000
Prepaid Expense	0	0	0	0	0
Current Investments	0	0	0	0	0
Short-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	1,481,000	1,456,000	1,628,000	1,542,000	2,071,000
Current Assets	8,039,000	8,005,000	7,673,000	7,706,000	8,453,000
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	94,162,000	NA	NA	NA	97,960,000
Gas PP&E in Service, Gross	7,738,000	NA	NA	NA	8,292,000
Other PP&E in Service, Gross	9,739,000	NA	NA	NA	10,580,000
PP&E in Service, Gross	111,639,000	123,301,000	124,439,000	125,582,000	116,832,000
Total Accumulated Depreciation	37,484,000	40,293,000	40,522,000	41,161,000	39,424,000
Net PP&E in Service	74,155,000	83,008,000	83,917,000	84,421,000	77,408,000
Construction Work in Progress	6,186,000	NA	NA	NA	6,995,000
Net Nuclear Fuel	1,650,000	NA	NA	NA	1,567,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	529,000	508,000	487,000	441,000	421,000
Net PP&E	82,520,000	83,516,000	84,404,000	84,862,000	86,391,000
Other Assets ($000)					
Securities - Noncurrent	0	0	0	0	0
Nuclear Decommissioning Trust	6,205,000	6,448,000	6,601,000	6,814,000	7,097,000
Other Investments	0	0	0	0	0
Investment in Partnerships	925,000	1,122,000	1,267,000	1,366,000	1,175,000
Noncurrent Investments	7,130,000	7,570,000	7,868,000	8,180,000	8,272,000
Goodwill	19,425,000	19,425,000	19,425,000	19,418,000	19,396,000
Intangible Assets other than Goodwill	226,000	NA	NA	NA	230,000
Total Intangible Assets	19,651,000	NA	NA	NA	19,626,000
Long-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Noncurrent	(1,892,000)	NA	NA	NA	(1,419,000)
Regulatory Assets	12,878,000	12,838,000	12,808,000	13,367,000	12,442,000
Total Other Assets	4,435,000	2,754,000	2,826,000	2,792,000	4,149,000
Total Assets	132,761,000	134,108,000	135,004,000	136,325,000	137,914,000
Tangible Assets	113,110,000	NA	NA	NA	118,288,000
Current Liabilities ($000)					
Short-term Debt	2,487,000	3,558,000	3,488,000	1,899,000	2,163,000
Current Portion of Long-term Debt	2,319,000	1,977,000	3,472,000	2,485,000	3,244,000
Short-term and Current Long-term Debt	4,806,000	5,535,000	6,960,000	4,384,000	5,407,000
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	503,000	526,000	506,000	538,000	525,000
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	0	0	0	0	0
Other Accounts Payable and Accrued Expense	3,378,000	2,566,000	2,609,000	3,272,000	3,594,000
Accounts Payable and Accrued Expense	3,881,000	3,092,000	3,115,000	3,810,000	4,119,000
Short-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Other Current Liabilities	2,864,000	2,314,000	2,391,000	2,626,000	2,956,000
Current Liabilities	11,551,000	10,941,000	12,466,000	10,820,000	12,482,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	1,111,000	1,115,000	1,108,000	1,105,000	1,103,000
Deferred Income Tax Liability	14,155,000	14,443,000	14,695,000	15,058,000	6,621,000
Deferred Tax Credit	493,000	537,000	534,000	534,000	539,000
Deferred Tax Liability	14,648,000	14,980,000	15,229,000	15,592,000	7,160,000
Non-current Long-term Debt	45,576,000	47,021,000	46,043,000	48,929,000	49,035,000
Long-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Regulatory Liabilities	6,881,000	6,972,000	7,048,000	7,027,000	15,330,000
Total Other Liabilities	11,953,000	11,893,000	11,816,000	11,210,000	11,067,000
Total Liabilities	91,720,000	92,922,000	93,710,000	94,683,000	96,177,000
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	41,033,000	41,179,000	41,284,000	41,631,000	41,739,000
Equity Attributable to Parent Company	41,033,000	41,179,000	41,284,000	41,631,000	41,739,000
Noncontrolling Interests	8,000	7,000	10,000	11,000	(2,000)
Total Equity	41,041,000	41,186,000	41,294,000	41,642,000	41,737,000
Tangible Common Equity	21,382,000	NA	NA	NA	22,113,000
Tangible Equity	21,390,000	NA	NA	NA	22,111,000
Capitalization ($000)					
Equity & Mezzanine Preferred	41,041,000	41,186,000	41,294,000	41,642,000	41,737,000
Total Debt	50,382,000	52,556,000	53,003,000	53,313,000	54,442,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Total Capitalization, at Book Value	91,423,000	93,742,000	94,297,000	94,955,000	96,179,000
Share Information					
Shares Issued	699,607,929	699,883,528	699,950,383	699,975,614	700,092,667
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	699,607,929	699,883,528	699,950,383	699,975,614	700,092,667

S&P Global Market Intelligence uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, S&P Global Market Intelligence mines data from documents filed by the company, surveys, and other sources of public information.

NYSE:EIX (MI KEY: 4056943; SPCIQ KEY: 301891)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	96,000	150,000	98,000	117,000	1,091,000
Gross Trade Accounts Receivable	776,000	743,000	891,000	1,160,000	771,000
Trade Accounts Receivable Allowance	62,000	55,000	58,000	55,000	54,000
Net Customer and Trade Accounts Receivable	714,000	688,000	833,000	1,105,000	717,000
Other Accounts Receivable	0	0	0	0	0
Accounts Receivable	714,000	688,000	833,000	1,105,000	717,000
Unbilled Revenue	370,000	266,000	399,000	352,000	212,000
Current Inventories	239,000	237,000	235,000	229,000	242,000
Prepaid Expense	1,000	NA	NA	179,000	457,000
Current Investments	NA	NA	NA	NA	NA
Short-term Energy Risk-mgmt Assets	73,000	69,000	58,000	36,000	105,000
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	630,000	636,000	923,000	740,000	905,000
Current Assets	2,123,000	2,046,000	2,546,000	2,758,000	3,729,000
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	38,257,000	NA	NA	NA	40,228,000
Gas PP&E in Service, Gross	0	0	0	0	0
Other PP&E in Service, Gross	4,633,000	NA	NA	NA	4,534,000
PP&E in Service, Gross	42,890,000	46,272,000	46,181,000	46,839,000	44,762,000
Total Accumulated Depreciation	9,000,000	9,321,000	8,914,000	9,173,000	9,355,000
Net PP&E in Service	33,890,000	36,951,000	37,267,000	37,666,000	35,407,000
Construction Work in Progress	2,790,000	NA	NA	NA	3,175,000
Net Nuclear Fuel	126,000	NA	NA	NA	126,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	194,000	217,000	245,000	295,000	342,000
Net PP&E	37,000,000	37,168,000	37,512,000	37,961,000	39,050,000
Other Assets ($000)					
Securities - Noncurrent	NA	NA	NA	NA	NA
Nuclear Decommissioning Trust	4,242,000	4,352,000	4,381,000	4,415,000	4,440,000
Other Investments	83,000	89,000	87,000	72,000	73,000
Investment in Partnerships	0	0	0	0	0
Noncurrent Investments	4,325,000	4,441,000	4,468,000	4,487,000	4,513,000
Goodwill	0	0	0	0	0
Intangible Assets other than Goodwill	NA	NA	NA	NA	NA
Total Intangible Assets	NA	NA	NA	NA	NA
Long-term Energy Risk-mgmt Assets	1,000	0	1,000	2,000	105,000
Deferred Taxes, Noncurrent	NA	NA	NA	NA	NA
Regulatory Assets	7,455,000	7,674,000	7,850,000	8,028,000	4,914,000
Total Other Assets	415,000	411,000	376,000	356,000	269,000
Total Assets	51,319,000	51,740,000	52,753,000	53,592,000	52,580,000
Tangible Assets	NA	NA	NA	NA	NA
Current Liabilities ($000)					
Short-term Debt	1,307,000	295,000	566,000	908,000	2,393,000
Current Portion of Long-term Debt	981,000	981,000	581,000	583,000	481,000
Short-term and Current Long-term Debt	2,288,000	1,276,000	1,147,000	1,491,000	2,874,000
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	NA	NA	NA	NA	NA
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	269,000	272,000	275,000	276,000	281,000
Other Accounts Payable and Accrued Expense	1,392,000	930,000	1,128,000	1,194,000	1,526,000
Accounts Payable and Accrued Expense	1,661,000	1,202,000	1,403,000	1,470,000	1,807,000
Short-term Energy Risk-mgmt Liabilities	216,000	237,000	190,000	3,000	1,000
Other Current Liabilities	1,747,000	1,701,000	1,862,000	2,445,000	2,386,000
Current Liabilities	5,912,000	4,416,000	4,602,000	5,409,000	7,068,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	1,354,000	1,358,000	1,377,000	1,378,000	943,000
Deferred Income Tax Liability	NA	NA	NA	NA	NA
Deferred Tax Credit	NA	NA	NA	NA	NA
Deferred Tax Liability	8,327,000	8,523,000	8,709,000	9,141,000	4,567,000
Non-current Long-term Debt	10,175,000	11,662,000	11,662,000	11,638,000	11,642,000
Long-term Energy Risk-mgmt Liabilities	941,000	989,000	869,000	0	0
Regulatory Liabilities	5,726,000	5,910,000	5,961,000	5,858,000	8,614,000
Total Other Liabilities	4,692,000	4,633,000	4,761,000	5,545,000	5,861,000
Total Liabilities	37,127,000	37,491,000	37,941,000	38,969,000	38,695,000
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	5,000	7,000	12,000	13,000	19,000
Total Mezzanine Level Items	5,000	7,000	12,000	13,000	19,000
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	11,996,000	12,051,000	12,146,000	12,416,000	11,671,000
Equity Attributable to Parent Company	11,996,000	12,051,000	12,146,000	12,416,000	11,671,000
Noncontrolling Interests	2,191,000	2,191,000	2,654,000	2,194,000	2,195,000
Total Equity	14,187,000	14,242,000	14,800,000	14,610,000	13,866,000
Tangible Common Equity	NA	NA	NA	NA	NA
Tangible Equity	NA	NA	NA	NA	NA
Capitalization ($000)					
Equity & Mezzanine Preferred	14,187,000	14,242,000	14,800,000	14,610,000	13,866,000
Total Debt	12,463,000	12,938,000	12,809,000	13,129,000	14,516,000

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Total Capitalization, at Book Value	26,655,000	27,187,000	27,621,000	27,752,000	28,401,000
Share Information					
Shares Issued	325,811,206	325,811,206	325,811,206	325,811,206	325,811,206
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	325,811,206	325,811,206	325,811,206	325,811,206	325,811,206

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Eversource Energy | Balance Sheet

NYSE:ES (MI KEY: 4057052; SPCIQ KEY: 292525)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	***2017 FQ1***	***2017 FQ2***	***2017 FQ3***	***2017 FQ4***
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	30,251	45,763	24,638	125,761	38,165
Gross Trade Accounts Receivable	1,047,931	1,082,651	1,032,945	1,116,759	1,120,791
Trade Accounts Receivable Allowance	200,630	203,200	199,000	196,800	195,708
Net Customer and Trade Accounts Receivable	847,301	879,451	833,945	919,959	925,083
Other Accounts Receivable	80,471	NA	NA	NA	NA
Accounts Receivable	927,772	879,451	833,945	919,959	925,083
Unbilled Revenue	168,490	166,710	158,183	146,634	201,361
Current Inventories	328,721	361,779	286,296	305,035	223,063
Prepaid Expense	99,755	162,544	139,519	143,794	122,628
Current Investments	24,558	15,615	14,340	13,445	15,381
Short-term Energy Risk-mgmt Assets	10,500	4,500	3,500	2,700	0
Deferred Taxes, Current	NA	NA	NA	NA	NA
Other Current Assets	887,625	875,037	870,393	746,142	961,418
Current Assets	2,477,672	2,511,399	2,330,814	2,403,470	2,487,099
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	23,458,500	23,719,600	24,045,600	24,351,300	25,276,000
Gas PP&E in Service, Gross	3,010,400	3,049,300	3,094,300	3,158,100	3,244,200
Other PP&E in Service, Gross	591,600	585,100	594,000	679,900	693,700
PP&E in Service, Gross	27,060,500	27,354,000	27,733,900	28,189,300	29,213,900
Total Accumulated Depreciation	6,722,400	6,858,800	6,969,400	7,112,900	7,133,800
Net PP&E in Service	20,338,100	20,495,200	20,764,500	21,076,400	22,080,100
Construction Work in Progress	1,012,400	1,146,700	1,307,000	1,460,900	1,537,400
Net Nuclear Fuel	0	0	0	0	0

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	0	0	0	0	0
Net PP&E	21,350,510	21,641,898	22,071,496	22,537,304	23,617,463
Other Assets ($000)					
Securities - Noncurrent	544,642	561,585	565,460	570,255	585,419
Nuclear Decommissioning Trust	0	0	0	0	0
Other Investments	NA	NA	NA	NA	NA
Investment in Partnerships	NA	NA	NA	NA	NA
Noncurrent Investments	NA	NA	NA	NA	NA
Goodwill	3,519,401	3,519,401	3,519,401	3,519,401	4,427,266
Intangible Assets other than Goodwill	NA	NA	NA	NA	NA
Total Intangible Assets	NA	NA	NA	NA	NA
Long-term Energy Risk-mgmt Assets	65,800	68,500	68,000	67,400	66,600
Deferred Taxes, Noncurrent	NA	NA	NA	NA	NA
Regulatory Assets	3,638,688	3,564,700	3,580,981	3,505,901	4,497,447
Total Other Assets	456,460	487,693	522,688	559,889	672,292
Total Assets	32,053,173	32,355,176	32,658,840	33,163,620	36,220,386
Tangible Assets	NA	NA	NA	NA	NA
Current Liabilities ($000)					
Short-term Debt	1,148,500	975,500	937,500	18,238	1,088,087
Current Portion of Long-term Debt	776,183	773,883	1,483,883	957,697	552,531
Short-term and Current Long-term Debt	1,924,683	1,749,383	2,421,383	975,935	1,640,618
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	NA	NA	NA	NA	NA
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	0	0	0	0	0
Other Accounts Payable and Accrued Expense	884,521	745,856	587,174	794,195	1,085,034
Accounts Payable and Accrued Expense	884,521	745,856	587,174	794,195	1,085,034
Short-term Energy Risk-mgmt Liabilities	79,700	72,900	67,500	63,300	58,900
Other Current Liabilities	749,701	765,626	709,652	787,001	804,493
Current Liabilities	3,638,605	3,333,765	3,785,709	2,620,431	3,589,045

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	1,141,514	1,077,593	1,073,510	946,629	1,228,091
Deferred Income Tax Liability	5,607,207	5,758,603	5,900,052	6,001,589	3,297,518
Deferred Tax Credit	NA	NA	NA	NA	NA
Deferred Tax Liability	NA	NA	NA	NA	NA
Non-current Long-term Debt	8,835,978	9,267,891	8,899,021	10,468,193	11,782,887
Long-term Energy Risk-mgmt Liabilities	413,676	415,795	402,138	391,910	377,257
Regulatory Liabilities	702,255	692,989	696,740	700,207	3,637,273
Total Other Liabilities	846,636	848,776	860,579	881,056	1,066,503
Total Liabilities	21,185,871	21,395,412	21,617,749	22,010,015	24,978,574
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	155,568	155,568	155,568	155,568	155,570
Total Minority Interest	155,568	155,568	155,568	155,568	155,570
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	155,568	155,568	155,568	155,568	155,570
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	10,711,734	10,804,196	10,885,523	10,998,037	11,086,242
Equity Attributable to Parent Company	10,711,734	10,804,196	10,885,523	10,998,037	11,086,242
Noncontrolling Interests	0	0	0	0	0
Total Equity	10,711,734	10,804,196	10,885,523	10,998,037	11,086,242
Tangible Common Equity	NA	NA	NA	NA	NA
Tangible Equity	NA	NA	NA	NA	NA
Capitalization ($000)					
Equity & Mezzanine Preferred	10,711,734	10,804,196	10,885,523	10,998,037	11,086,242
Total Debt	10,760,661	11,017,274	11,320,404	11,444,128	13,423,505

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Total Capitalization, at Book Value	21,627,963	21,977,038	22,361,495	22,597,733	24,665,317
Share Information					
Shares Issued	333,878,402	333,878,402	333,878,402	333,878,402	333,878,402
Treasury Shares	16,992,594	16,992,594	16,992,594	16,992,594	16,992,594
Common Shares Outstanding (actual)	316,885,808	316,885,808	316,885,808	316,885,808	316,885,808

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OGE Energy Corp. | Balance Sheet

NYSE:OGE (MI KEY: 4057055; SPCIQ KEY: 293569)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	***2017 FQ1***	***2017 FQ2***	***2017 FQ3***	***2017 FQ4***
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	300	0	0	0	14,400
Gross Trade Accounts Receivable	174,500	137,700	186,100	263,000	190,200
Trade Accounts Receivable Allowance	1,500	1,100	1,100	1,500	1,500
Net Customer and Trade Accounts Receivable	173,000	136,600	185,000	261,500	188,700
Other Accounts Receivable	21,900	19,200	16,900	18,200	7,700
Accounts Receivable	194,900	155,800	201,900	279,700	196,400
Unbilled Revenue	59,700	56,200	86,700	69,800	66,500
Current Inventories	161,500	169,200	160,400	157,400	165,100
Prepaid Expense	NA	NA	NA	NA	NA
Current Investments	0	0	0	0	0
Short-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	133,100	156,900	183,500	92,900	54,600
Current Assets	549,500	538,100	632,500	599,800	497,000
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	NA	NA	NA	NA	NA
Gas PP&E in Service, Gross	NA	NA	NA	NA	NA
Other PP&E in Service, Gross	NA	NA	NA	NA	NA
PP&E in Service, Gross	10,605,000	10,730,800	10,827,400	10,890,300	10,859,400
Total Accumulated Depreciation	3,445,000	3,503,800	3,536,900	3,584,300	3,433,000
Net PP&E in Service	7,160,000	7,227,000	7,290,500	7,306,000	7,426,400
Construction Work in Progress	495,100	673,300	797,800	893,900	867,500
Net Nuclear Fuel	0	0	0	0	0

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	0	0	0	0	0
Net PP&E	7,655,100	7,900,300	8,088,300	8,199,900	8,293,900
Other Assets ($000)					
Securities - Noncurrent	0	0	0	0	0
Nuclear Decommissioning Trust	0	0	0	0	0
Other Investments	73,600	75,500	75,800	76,400	76,700
Investment in Partnerships	1,158,600	1,158,900	1,159,100	1,158,100	1,160,400
Noncurrent Investments	1,232,200	1,234,400	1,234,900	1,234,500	1,237,100
Goodwill	0	0	0	0	0
Intangible Assets other than Goodwill	41,100	NA	NA	NA	46,000
Total Intangible Assets	41,100	NA	NA	NA	46,000
Long-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Noncurrent	0	0	0	0	0
Regulatory Assets	404,800	403,100	406,800	373,400	283,000
Total Other Assets	56,900	59,000	58,000	56,100	55,700
Total Assets	9,939,600	10,134,900	10,420,500	10,463,700	10,412,700
Tangible Assets	9,898,500	NA	NA	NA	10,366,700
Current Liabilities ($000)					
Short-term Debt	236,200	128,200	193,200	146,500	168,400
Current Portion of Long-term Debt	224,700	224,800	224,900	349,700	249,800
Short-term and Current Long-term Debt	460,900	353,000	418,100	496,200	418,200
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	40,400	33,000	43,700	39,000	44,000
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	77,700	78,600	79,100	79,500	80,700
Other Accounts Payable and Accrued Expense	352,200	355,400	321,900	302,400	377,200
Accounts Payable and Accrued Expense	470,300	467,000	444,700	420,900	501,900
Short-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Other Current Liabilities	96,000	95,000	63,400	36,400	30,400
Current Liabilities	1,027,200	915,000	926,200	953,500	950,500

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	274,800	276,500	275,600	185,800	192,700
Deferred Income Tax Liability	2,334,500	2,332,000	2,379,400	2,465,900	1,227,800
Deferred Tax Credit	NA	NA	NA	NA	NA
Deferred Tax Liability	NA	NA	NA	NA	NA
Non-current Long-term Debt	2,405,800	2,703,200	2,863,000	2,749,500	2,749,600
Long-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Regulatory Liabilities	299,700	306,700	321,600	331,700	1,283,400
Total Other Liabilities	153,800	157,100	162,700	160,500	157,600
Total Liabilities	6,495,800	6,690,500	6,928,500	6,846,900	6,561,600
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	3,443,800	3,444,400	3,492,000	3,616,800	3,851,100
Equity Attributable to Parent Company	3,443,800	3,444,400	3,492,000	3,616,800	3,851,100
Noncontrolling Interests	0	0	0	0	0
Total Equity	3,443,800	3,444,400	3,492,000	3,616,800	3,851,100
Tangible Common Equity	3,402,700	NA	NA	NA	3,805,100
Tangible Equity	3,402,700	NA	NA	NA	3,805,100
Capitalization ($000)					
Equity & Mezzanine Preferred	3,443,800	3,444,400	3,492,000	3,616,800	3,851,100
Total Debt	2,866,700	3,056,200	3,281,100	3,245,700	3,167,800

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Total Capitalization, at Book Value	6,310,500	6,500,600	6,773,100	6,862,500	7,018,900
Share Information					
Shares Issued	199,700,000	199,704,099	199,704,288	199,705,254	199,700,000
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	199,700,000	199,704,099	199,704,288	199,705,254	199,700,000

S&P Global Market Intelligence uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, S&P Global Market Intelligence mines data from documents filed by the company, surveys, and other sources of public information.

Pinnacle West Capital Corporation | Balance Sheet

NYSE:PNW (MI KEY: 4056951; SPCIQ KEY: 296957)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	***2017 FQ1***	***2017 FQ2***	***2017 FQ3***	***2017 FQ4***
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	8,881	3,028	4,953	10,674	13,892
Gross Trade Accounts Receivable	NA	NA	NA	NA	NA
Trade Accounts Receivable Allowance	NA	NA	NA	NA	NA
Net Customer and Trade Accounts Receivable	NA	NA	NA	NA	NA
Other Accounts Receivable	NA	NA	NA	NA	NA
Accounts Receivable	251,205	198,760	295,188	422,507	302,634
Unbilled Revenue	107,949	101,226	213,703	151,976	112,434
Current Inventories	282,587	283,254	288,024	284,468	289,270
Prepaid Expense	0	0	0	0	0
Current Investments	0	0	0	0	0
Short-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	171,597	208,728	266,336	304,580	298,058
Current Assets	822,219	794,996	1,068,204	1,174,205	1,016,288
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	17,341,888	17,436,720	17,227,444	17,310,294	17,798,061
Gas PP&E in Service, Gross	0	0	0	0	0
Other PP&E in Service, Gross	351,050	NA	NA	NA	351,050
PP&E in Service, Gross	17,692,938	17,436,720	17,227,444	17,310,294	18,149,111
Total Accumulated Depreciation	6,207,635	6,060,254	5,951,653	6,037,467	6,369,940
Net PP&E in Service	11,485,303	11,376,466	11,275,791	11,272,827	11,779,171
Construction Work in Progress	1,019,947	1,005,797	1,195,076	1,379,501	1,291,498
Net Nuclear Fuel	119,004	135,821	118,909	135,460	117,408

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	NA	112,548	111,580	110,613	NA
Net PP&E	12,624,254	12,630,632	12,701,356	12,898,401	13,188,077
Other Assets ($000)					
Securities - Noncurrent	NA	NA	NA	NA	NA
Nuclear Decommissioning Trust	779,586	805,048	822,244	841,980	871,000
Other Investments	0	0	0	0	0
Investment in Partnerships	0	0	0	0	0
Noncurrent Investments	779,586	805,048	822,244	841,980	871,000
Goodwill	0	0	0	0	0
Intangible Assets other than Goodwill	90,022	251,208	265,926	256,198	257,189
Total Intangible Assets	90,022	251,208	265,926	256,198	257,189
Long-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Noncurrent	NA	NA	NA	NA	NA
Regulatory Assets	1,313,428	1,321,473	1,415,091	1,381,179	1,202,302
Total Other Assets	374,744	389,468	396,906	425,904	484,226
Total Assets	16,004,253	16,192,825	16,669,727	16,977,867	17,019,082
Tangible Assets	15,914,231	15,941,617	16,403,801	16,721,669	16,761,893
Current Liabilities ($000)					
Short-term Debt	177,200	207,297	482,000	131,400	95,400
Current Portion of Long-term Debt	125,000	125,000	207,000	207,000	82,000
Short-term and Current Long-term Debt	302,200	332,297	689,000	338,400	177,400
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	52,835	48,576	53,046	49,218	56,397
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	82,520	76,149	72,585	69,690	70,388
Other Accounts Payable and Accrued Expense	476,521	433,009	494,084	465,537	483,055
Accounts Payable and Accrued Expense	611,876	557,734	619,715	584,445	609,840
Short-term Energy Risk-mgmt Liabilities	NA	NA	NA	NA	NA
Other Current Liabilities	378,870	303,782	329,879	380,298	410,612
Current Liabilities	1,292,946	1,193,813	1,638,594	1,303,143	1,197,852

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	509,310	469,746	460,368	409,871	327,300
Deferred Income Tax Liability	2,945,232	2,955,441	3,048,007	3,182,400	1,690,805
Deferred Tax Credit	210,162	209,818	206,969	205,870	205,575
Deferred Tax Liability	3,155,394	3,165,259	3,254,976	3,388,270	1,896,380
Non-current Long-term Debt	4,021,785	4,273,890	4,192,520	4,491,048	4,789,713
Long-term Energy Risk-mgmt Liabilities	NA	NA	NA	NA	NA
Regulatory Liabilities	948,916	948,293	940,106	891,715	2,452,536
Total Other Liabilities	1,139,990	1,175,884	1,193,086	1,216,213	1,219,571
Total Liabilities	11,068,341	11,226,885	11,679,650	11,700,260	11,883,352
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	4,803,622	4,828,776	4,859,412	5,142,068	5,006,690
Equity Attributable to Parent Company	4,803,622	4,828,776	4,859,412	5,142,068	5,006,690
Noncontrolling Interests	132,290	137,164	130,665	135,539	129,040
Total Equity	4,935,912	4,965,940	4,990,077	5,277,607	5,135,730
Tangible Common Equity	4,713,600	4,577,568	4,593,486	4,885,870	4,749,501
Tangible Equity	4,845,890	4,714,732	4,724,151	5,021,409	4,878,541
Capitalization ($000)					
Equity & Mezzanine Preferred	4,935,912	4,965,940	4,990,077	5,277,607	5,135,730
Total Debt	4,323,985	4,606,187	4,881,520	4,829,448	4,967,113

	2016 FQ4	***2017 FQ1***	***2017 FQ2***	***2017 FQ3***	***2017 FQ4***
Total Capitalization, at Book Value	9,259,897	9,572,127	9,871,597	10,107,055	10,102,843
Share Information					
Shares Issued	111,392,053	111,587,048	111,642,680	111,666,876	111,816,170
Treasury Shares	55,317	29,195	19,298	9,864	64,463
Common Shares Outstanding (actual)	111,336,736	111,557,853	111,623,382	111,657,012	111,751,707

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NYSE:PNM (MI KEY: 4006880; SPCIQ KEY: 298441)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	4,522	2,283	2,193	43,149	3,974
Gross Trade Accounts Receivable	88,221	83,446	87,684	108,491	91,554
Trade Accounts Receivable Allowance	1,209	1,212	1,086	1,063	1,081
Net Customer and Trade Accounts Receivable	87,012	82,234	86,598	107,428	90,473
Other Accounts Receivable	34,311	33,051	32,005	23,328	24,461
Accounts Receivable	121,323	115,285	118,603	130,756	114,934
Unbilled Revenue	58,284	41,808	69,849	57,241	54,055
Current Inventories	73,027	66,140	67,007	68,179	66,502
Prepaid Expense	0	0	0	0	0
Current Investments	38,360	29,664	20,968	12,272	3,576
Short-term Energy Risk-mgmt Assets	5,224	4,586	3,847	3,093	1,088
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	77,299	67,003	71,120	59,845	50,291
Current Assets	378,039	326,769	353,587	374,535	294,420
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	NA	NA	NA	NA	NA
Gas PP&E in Service, Gross	0	0	0	0	0
Other PP&E in Service, Gross	NA	NA	NA	NA	NA
PP&E in Service, Gross	6,947,938	7,013,102	7,085,319	7,137,050	7,241,689
Total Accumulated Depreciation	2,334,938	2,373,542	2,395,590	2,431,695	2,592,692
Net PP&E in Service	4,613,000	4,639,560	4,689,729	4,705,355	4,648,997
Construction Work in Progress	208,206	232,056	252,759	301,466	245,933
Net Nuclear Fuel	86,913	87,379	88,586	88,702	88,701

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	0	0	0	0	0
Net PP&E	4,908,119	4,958,995	5,031,074	5,095,523	4,983,631
Other Assets ($000)					
Securities - Noncurrent	272,977	286,099	295,026	306,444	323,524
Nuclear Decommissioning Trust	NA	NA	NA	NA	NA
Other Investments	57,187	56,165	55,256	54,344	53,567
Investment in Partnerships	0	0	0	0	16,510
Noncurrent Investments	330,164	342,264	350,282	360,788	393,601
Goodwill	278,297	278,297	278,297	278,297	278,297
Intangible Assets other than Goodwill	0	0	0	0	0
Total Intangible Assets	278,297	278,297	278,297	278,297	278,297
Long-term Energy Risk-mgmt Assets	0	0	4,106	3,846	3,556
Deferred Taxes, Noncurrent	NA	NA	NA	NA	NA
Regulatory Assets	501,223	496,012	490,454	489,416	600,672
Total Other Assets	75,238	75,342	76,645	94,849	91,926
Total Assets	6,471,080	6,477,679	6,584,445	6,697,254	6,646,103
Tangible Assets	6,192,783	6,199,382	6,306,148	6,418,957	6,367,806
Current Liabilities ($000)					
Short-term Debt	287,100	303,100	373,500	266,500	305,400
Current Portion of Long-term Debt	273,348	414,856	174,257	165,312	256,895
Short-term and Current Long-term Debt	560,448	717,956	547,757	431,812	562,295
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	NA	NA	NA	NA	NA
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	11,374	11,207	11,023	10,951	11,028
Other Accounts Payable and Accrued Expense	168,024	161,186	134,182	192,618	204,980
Accounts Payable and Accrued Expense	179,398	172,393	145,205	203,569	216,008
Short-term Energy Risk-mgmt Liabilities	2,339	360	1,990	1,279	1,182
Other Current Liabilities	62,923	71,427	71,618	74,225	56,159
Current Liabilities	805,108	962,136	766,570	710,885	835,644

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	125,844	121,632	119,243	116,812	94,003
Deferred Income Tax Liability	884,633	NA	NA	NA	491,479
Deferred Tax Credit	56,017	NA	NA	NA	55,731
Deferred Tax Liability	940,650	948,177	971,440	1,015,967	547,210
Non-current Long-term Debt	2,119,364	1,969,304	2,199,105	2,282,390	2,180,750
Long-term Energy Risk-mgmt Liabilities	0	0	4,106	3,846	3,556
Regulatory Liabilities	455,649	453,580	454,952	456,740	933,578
Total Other Liabilities	268,064	256,337	262,055	265,939	278,385
Total Liabilities	4,714,679	4,711,166	4,777,471	4,852,579	4,873,126
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	11,529	11,529	11,529	11,529	11,529
Total Minority Interest	11,529	11,529	11,529	11,529	11,529
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	11,529	11,529	11,529	11,529	11,529
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	1,675,952	1,686,640	1,727,260	1,765,737	1,695,253
Equity Attributable to Parent Company	1,675,952	1,686,640	1,727,260	1,765,737	1,695,253
Noncontrolling Interests	68,920	68,344	68,185	67,409	66,195
Total Equity	1,744,872	1,754,984	1,795,445	1,833,146	1,761,448
Tangible Common Equity	1,397,655	1,408,343	1,448,963	1,487,440	1,416,956
Tangible Equity	1,466,575	1,476,687	1,517,148	1,554,849	1,483,151
Capitalization ($000)					
Equity & Mezzanine Preferred	1,744,872	1,754,984	1,795,445	1,833,146	1,761,448
Total Debt	2,679,812	2,687,260	2,746,862	2,714,202	2,743,045

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Total Capitalization, at Book Value	4,436,213	4,453,773	4,553,836	4,558,877	4,516,022
Share Information					
Shares Issued	79,653,624	79,653,624	79,653,624	79,653,624	79,653,624
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	79,653,624	79,653,624	79,653,624	79,653,624	79,653,624

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NYSE:SO (MI KEY: 4004298; SPCIQ KEY: 120623)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets ($000)					
Cash and Cash Equivalents	1,975,000	1,094,000	1,433,000	1,841,000	2,130,000
Gross Trade Accounts Receivable	1,583,000	1,560,000	1,600,000	1,744,000	1,806,000
Trade Accounts Receivable Allowance	43,000	53,000	52,000	43,000	44,000
Net Customer and Trade Accounts Receivable	1,540,000	1,507,000	1,548,000	1,701,000	1,762,000
Other Accounts Receivable	1,544,000	1,517,000	1,565,000	1,205,000	1,476,000
Accounts Receivable	3,084,000	3,024,000	3,113,000	2,906,000	3,238,000
Unbilled Revenue	706,000	589,000	593,000	595,000	810,000
Current Inventories	2,151,000	2,164,000	2,085,000	2,070,000	2,032,000
Prepaid Expense	364,000	401,000	361,000	365,000	452,000
Current Investments	NA	NA	NA	NA	NA
Short-term Energy Risk-mgmt Assets	73,000	48,000	23,000	21,000	10,000
Deferred Taxes, Current	NA	NA	NA	NA	NA
Other Current Assets	1,369,000	1,107,000	1,229,000	1,404,000	1,400,000
Current Assets	9,722,000	8,427,000	8,837,000	9,202,000	10,072,000
Property, Plant and Equipment ($000)					
Electric PP&E in Service, Gross	83,165,000	99,774,000	101,021,000	102,014,000	86,482,000
Gas PP&E in Service, Gross	11,996,000	NA	NA	NA	13,078,000
Other PP&E in Service, Gross	3,255,000	NA	NA	NA	3,982,000
PP&E in Service, Gross	98,416,000	99,774,000	101,021,000	102,014,000	103,542,000
Total Accumulated Depreciation	29,852,000	30,330,000	30,667,000	31,164,000	31,457,000
Net PP&E in Service	68,564,000	69,444,000	70,354,000	70,850,000	72,085,000
Construction Work in Progress	8,977,000	9,465,000	7,440,000	8,026,000	6,904,000
Net Nuclear Fuel	905,000	902,000	892,000	865,000	883,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	0	0	0	0	0
Net PP&E	78,446,000	79,811,000	78,686,000	79,741,000	79,872,000
Other Assets ($000)					
Securities - Noncurrent	0	0	0	0	0
Nuclear Decommissioning Trust	1,606,000	1,678,000	1,722,000	1,783,000	1,832,000
Other Investments	1,044,000	1,073,000	1,012,000	1,024,000	1,024,000
Investment in Partnerships	1,549,000	1,615,000	1,632,000	1,637,000	1,513,000
Noncurrent Investments	4,199,000	4,366,000	4,366,000	4,444,000	4,369,000
Goodwill	6,251,000	6,251,000	6,271,000	6,267,000	6,268,000
Intangible Assets other than Goodwill	970,000	935,000	929,000	902,000	873,000
Total Intangible Assets	7,221,000	7,186,000	7,200,000	7,169,000	7,141,000
Long-term Energy Risk-mgmt Assets	25,000	6,000	8,000	13,000	7,000
Deferred Taxes, Noncurrent	1,629,000	1,647,000	1,325,000	1,318,000	825,000
Regulatory Assets	NA	NA	NA	NA	NA
Total Other Assets	8,455,000	8,317,000	8,262,000	8,428,000	8,719,000
Total Assets	109,697,000	109,760,000	108,684,000	110,315,000	111,005,000
Tangible Assets	102,476,000	102,574,000	101,484,000	103,146,000	103,864,000
Current Liabilities ($000)					
Short-term Debt	2,241,000	2,818,000	3,274,000	2,579,000	2,439,000
Current Portion of Long-term Debt	2,587,000	3,269,000	3,031,000	3,505,000	3,892,000
Short-term and Current Long-term Debt	4,828,000	6,087,000	6,305,000	6,084,000	6,331,000
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	518,000	453,000	508,000	443,000	488,000
Income Taxes Payable	193,000	258,000	125,000	176,000	6,000
Customer Security Deposits	558,000	541,000	546,000	550,000	542,000
Other Accounts Payable and Accrued Expense	5,281,000	3,408,000	3,928,000	4,214,000	4,671,000
Accounts Payable and Accrued Expense	6,550,000	4,660,000	5,107,000	5,383,000	5,707,000
Short-term Energy Risk-mgmt Liabilities	134,000	93,000	106,000	25,000	43,000
Other Current Liabilities	1,405,000	1,444,000	1,233,000	1,111,000	1,513,000
Current Liabilities	12,917,000	12,284,000	12,751,000	12,603,000	13,594,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities ($000)					
Postretirement Benefits	2,299,000	2,234,000	2,156,000	2,139,000	2,256,000
Deferred Income Tax Liability	14,092,000	14,307,000	13,529,000	14,321,000	6,842,000
Deferred Tax Credit	2,447,000	2,479,000	2,513,000	2,290,000	9,523,000
Deferred Tax Liability	16,539,000	16,786,000	16,042,000	16,611,000	16,365,000
Non-current Long-term Debt	42,629,000	42,786,000	43,885,000	44,042,000	44,462,000
Long-term Energy Risk-mgmt Liabilities	33,000	38,000	31,000	23,000	24,000
Regulatory Liabilities	NA	NA	NA	NA	NA
Total Other Liabilities	8,386,000	8,354,000	8,409,000	8,538,000	8,452,000
Total Liabilities	82,803,000	82,482,000	83,274,000	83,956,000	85,153,000
Mezzanine ($000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	118,000	118,000	118,000	361,000	324,000
Total Minority Interest	118,000	118,000	118,000	361,000	324,000
Other Mezzanine Items	164,000	164,000	51,000	59,000	0
Total Mezzanine Level Items	282,000	282,000	169,000	420,000	324,000
Equity ($000)					
Total Preferred Equity	0	0	0	0	0
Common Equity	24,758,000	25,094,000	23,372,000	24,082,000	24,167,000
Equity Attributable to Parent Company	24,758,000	25,094,000	23,372,000	24,082,000	24,167,000
Noncontrolling Interests	1,854,000	1,902,000	1,869,000	1,857,000	1,361,000
Total Equity	26,612,000	26,996,000	25,241,000	25,939,000	25,528,000
Tangible Common Equity	17,537,000	17,908,000	16,172,000	16,913,000	17,026,000
Tangible Equity	19,391,000	19,810,000	18,041,000	18,770,000	18,387,000
Capitalization ($000)					
Equity & Mezzanine Preferred	26,612,000	26,996,000	25,241,000	25,939,000	25,528,000
Total Debt	47,457,000	48,873,000	50,190,000	50,126,000	50,793,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Total Capitalization, at Book Value	74,351,000	76,151,000	75,600,000	76,485,000	76,645,000
Share Information					
Shares Issued	991,213,000	995,453,000	1,000,342,000	1,004,521,000	1,008,532,000
Treasury Shares	819,000	854,000	868,000	894,000	929,000
Common Shares Outstanding (actual)	990,394,000	994,598,783	999,474,028	1,003,627,691	1,007,603,000

S&P Global Market Intelligence uses a variety of sources to retrieve financial information for each company we cover. For Energy companies, S&P Global Market Intelligence mines data from documents filed by the company, surveys, and other sources of public information.

Canadian Utilities Limited | Balance Sheet

TSX:CU, TSX:CU.X (MI KEY: 4142320; SPCIQ KEY: 873742)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	***2017 FQ1***	***2017 FQ2***	***2017 FQ3***	***2017 FQ4***
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	IFRS	IFRS	IFRS	IFRS	IFRS
Current Assets (C$000)					
Cash and Cash Equivalents	345,000	515,000	459,000	566,000	425,000
Gross Trade Accounts Receivable	NA	NA	NA	NA	NA
Trade Accounts Receivable Allowance	NA	NA	NA	NA	NA
Net Customer and Trade Accounts Receivable	518,000	495,000	439,000	463,000	619,000
Other Accounts Receivable	47,000	47,000	65,000	64,000	50,000
Accounts Receivable	565,000	542,000	504,000	527,000	669,000
Unbilled Revenue	NA	NA	NA	NA	NA
Current Inventories	38,000	41,000	42,000	43,000	40,000
Prepaid Expense	37,000	45,000	51,000	54,000	45,000
Current Investments	NA	NA	NA	NA	NA
Short-term Energy Risk-mgmt Assets	NA	NA	NA	NA	NA
Deferred Taxes, Current	NA	NA	NA	NA	NA
Other Current Assets	0	NA	NA	NA	861,000
Current Assets	985,000	1,143,000	1,056,000	1,190,000	2,040,000
Property, Plant and Equipment (C$000)					
Electric PP&E in Service, Gross	19,576,000	19,747,000	19,993,000	20,078,000	20,334,000
Gas PP&E in Service, Gross	0	0	0	0	0
Other PP&E in Service, Gross	1,770,000	1,750,000	1,736,000	1,741,000	1,790,000
PP&E in Service, Gross	21,346,000	21,497,000	21,729,000	21,819,000	22,124,000
Total Accumulated Depreciation	5,665,000	5,783,000	5,877,000	5,971,000	5,947,000
Net PP&E in Service	15,681,000	15,714,000	15,852,000	15,848,000	16,177,000
Construction Work in Progress	682,000	740,000	661,000	809,000	609,000
Net Nuclear Fuel	0	0	0	0	0

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	0	0	0	0	0
Net PP&E	16,363,000	16,454,000	16,513,000	16,657,000	16,786,000
Other Assets (C$000)					
Securities - Noncurrent	0	0	0	0	0
Nuclear Decommissioning Trust	0	0	0	0	0
Other Investments	0	0	0	0	0
Investment in Partnerships	388,000	391,000	371,000	364,000	196,000
Noncurrent Investments	388,000	391,000	371,000	364,000	196,000
Goodwill	0	0	0	0	0
Intangible Assets other than Goodwill	526,000	530,000	542,000	549,000	563,000
Total Intangible Assets	526,000	530,000	542,000	549,000	563,000
Long-term Energy Risk-mgmt Assets	NA	NA	NA	NA	NA
Deferred Taxes, Noncurrent	55,000	58,000	63,000	64,000	62,000
Regulatory Assets	0	0	0	0	0
Total Other Assets	464,000	539,000	668,000	837,000	1,178,000
Total Assets	18,781,000	19,115,000	19,213,000	19,661,000	20,825,000
Tangible Assets	18,255,000	18,585,000	18,671,000	19,112,000	20,262,000
Current Liabilities (C$000)					
Short-term Debt	60,000	46,000	179,000	538,000	7,000
Current Portion of Long-term Debt	169,000	169,000	169,000	170,000	20,000
Short-term and Current Long-term Debt	229,000	215,000	348,000	708,000	27,000
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	NA	NA	NA	NA	NA
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	NA	NA	NA	NA	NA
Other Accounts Payable and Accrued Expense	605,000	676,000	607,000	616,000	824,000
Accounts Payable and Accrued Expense	605,000	676,000	607,000	616,000	824,000
Short-term Energy Risk-mgmt Liabilities	NA	NA	NA	NA	NA
Other Current Liabilities	58,000	68,000	76,000	85,000	97,000
Current Liabilities	892,000	959,000	1,031,000	1,409,000	948,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Liabilities (C$000)					
Postretirement Benefits	302,000	360,000	393,000	331,000	340,000
Deferred Income Tax Liability	1,163,000	1,185,000	1,207,000	1,255,000	1,248,000
Deferred Tax Credit	0	0	0	0	0
Deferred Tax Liability	1,163,000	1,185,000	1,207,000	1,255,000	1,248,000
Non-current Long-term Debt	8,149,000	8,180,000	8,159,000	8,145,000	9,895,000
Long-term Energy Risk-mgmt Liabilities	NA	NA	NA	NA	NA
Regulatory Liabilities	NA	NA	NA	NA	NA
Total Other Liabilities	1,855,000	1,900,000	1,928,000	1,996,000	1,932,000
Total Liabilities	12,361,000	12,584,000	12,718,000	13,136,000	14,363,000
Mezzanine (C$000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity (C$000)					
Total Preferred Equity	1,483,000	1,483,000	1,483,000	1,483,000	1,483,000
Common Equity	4,735,000	4,861,000	4,825,000	4,855,000	4,792,000
Equity Attributable to Parent Company	6,218,000	6,344,000	6,308,000	6,338,000	6,275,000
Noncontrolling Interests	202,000	187,000	187,000	187,000	187,000
Total Equity	6,420,000	6,531,000	6,495,000	6,525,000	6,462,000
Tangible Common Equity	4,209,000	4,331,000	4,283,000	4,306,000	4,229,000
Tangible Equity	5,894,000	6,001,000	5,953,000	5,976,000	5,899,000
Capitalization (C$000)					
Equity & Mezzanine Preferred	6,420,000	6,531,000	6,495,000	6,525,000	6,462,000
Total Debt	8,378,000	8,395,000	8,507,000	8,853,000	9,922,000

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Total Capitalization, at Book Value	14,798,000	14,926,000	15,002,000	15,378,000	16,384,000
Share Information					
Shares Issued	268,553,785	269,423,604	270,354,931	270,721,996	271,102,055
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	268,553,785	269,423,604	270,354,931	270,721,996	271,102,055

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Emera Incorporated | Balance Sheet

TSX:EMA (MI KEY: 4072693; SPCIQ KEY: 877188)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets (C$000)					
Cash and Cash Equivalents	404,000	255,000	217,000	221,000	438,000
Gross Trade Accounts Receivable	715,000	NA	NA	NA	805,000
Trade Accounts Receivable Allowance	13,000	NA	NA	NA	12,000
Net Customer and Trade Accounts Receivable	702,000	996,000	923,000	896,000	793,000
Other Accounts Receivable	91,000	39,000	40,000	15,000	99,000
Accounts Receivable	793,000	1,035,000	963,000	911,000	892,000
Unbilled Revenue	270,000	NA	NA	NA	278,000
Current Inventories	472,000	442,000	469,000	452,000	418,000
Prepaid Expense	57,000	277,000	228,000	147,000	59,000
Current Investments	8,000	NA	NA	NA	8,000
Short-term Energy Risk-mgmt Assets	145,000	135,000	121,000	128,000	141,000
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	362,000	164,000	161,000	169,000	292,000
Current Assets	2,511,000	2,308,000	2,159,000	2,028,000	2,526,000
Property, Plant and Equipment (C$000)					
Electric PP&E in Service, Gross	NA	NA	NA	NA	NA
Gas PP&E in Service, Gross	NA	NA	NA	NA	NA
Other PP&E in Service, Gross	NA	NA	NA	NA	NA
PP&E in Service, Gross	23,673,000	25,098,000	24,912,000	24,477,000	24,197,000
Total Accumulated Depreciation	7,787,000	7,843,000	7,843,000	7,785,000	7,824,000
Net PP&E in Service	15,886,000	17,255,000	17,069,000	16,692,000	16,373,000
Construction Work in Progress	1,404,000	NA	NA	NA	622,000
Net Nuclear Fuel	0	0	0	0	0

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Other Net PP&E	0	0	0	0	0
Net PP&E	17,290,000	17,255,000	17,069,000	16,692,000	16,995,000
Other Assets (C$000)					
Securities - Noncurrent	48,000	55,000	55,000	55,000	0
Nuclear Decommissioning Trust	0	0	0	0	0
Other Investments	488,000	487,000	485,000	483,000	481,000
Investment in Partnerships	947,000	1,030,000	1,131,000	1,167,000	1,215,000
Noncurrent Investments	1,483,000	1,572,000	1,671,000	1,705,000	1,696,000
Goodwill	6,213,000	6,165,000	6,005,000	5,775,000	5,805,000
Intangible Assets other than Goodwill	NA	NA	NA	NA	NA
Total Intangible Assets	NA	NA	NA	NA	NA
Long-term Energy Risk-mgmt Assets	131,000	117,000	105,000	101,000	112,000
Deferred Taxes, Noncurrent	125,000	61,000	87,000	111,000	138,000
Regulatory Assets	1,242,000	1,274,000	1,279,000	1,257,000	1,238,000
Total Other Assets	226,000	194,000	209,000	213,000	261,000
Total Assets	29,221,000	28,946,000	28,584,000	27,882,000	28,771,000
Tangible Assets	NA	NA	NA	NA	NA
Current Liabilities (C$000)					
Short-term Debt	961,000	1,007,000	1,039,000	939,000	1,241,000
Current Portion of Long-term Debt	476,000	473,000	1,175,000	1,105,000	741,000
Short-term and Current Long-term Debt	1,437,000	1,480,000	2,214,000	2,044,000	1,982,000
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	96,000	NA	NA	NA	78,000
Income Taxes Payable	19,000	17,000	3,000	4,000	1,000
Customer Security Deposits	NA	NA	NA	NA	NA
Other Accounts Payable and Accrued Expense	1,395,000	970,000	963,000	1,070,000	1,306,000
Accounts Payable and Accrued Expense	1,510,000	987,000	966,000	1,074,000	1,385,000
Short-term Energy Risk-mgmt Liabilities	325,000	137,000	129,000	145,000	227,000
Other Current Liabilities	452,000	645,000	496,000	717,000	352,000
Current Liabilities	3,724,000	3,249,000	3,805,000	3,980,000	3,946,000

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Other Liabilities (C$000)					
Postretirement Benefits	669,000	644,000	636,000	590,000	559,000
Deferred Income Tax Liability	1,672,000	1,719,000	1,747,000	1,776,000	1,011,000
Deferred Tax Credit	NA	NA	NA	NA	NA
Deferred Tax Liability	NA	NA	NA	NA	NA
Non-current Long-term Debt	14,276,000	14,273,000	13,446,000	13,059,000	13,140,000
Long-term Energy Risk-mgmt Liabilities	150,000	110,000	99,000	83,000	83,000
Regulatory Liabilities	1,277,000	1,265,000	1,250,000	1,132,000	2,242,000
Total Other Liabilities	637,000	644,000	650,000	611,000	609,000
Total Liabilities	22,405,000	21,904,000	21,633,000	21,231,000	21,590,000
Mezzanine (C$000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity (C$000)					
Total Preferred Equity	709,000	709,000	709,000	709,000	709,000
Common Equity	5,995,000	6,221,000	6,131,000	5,833,000	6,380,000
Equity Attributable to Parent Company	6,704,000	6,930,000	6,840,000	6,542,000	7,089,000
Noncontrolling Interests	112,000	112,000	111,000	109,000	92,000
Total Equity	6,816,000	7,042,000	6,951,000	6,651,000	7,181,000
Tangible Common Equity	NA	NA	NA	NA	NA
Tangible Equity	NA	NA	NA	NA	NA
Capitalization (C$000)					
Equity & Mezzanine Preferred	6,816,000	7,042,000	6,951,000	6,651,000	7,181,000
Total Debt	15,713,000	15,753,000	15,660,000	15,103,000	15,122,000

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Total Capitalization, at Book Value	22,529,000	22,795,000	22,611,000	21,754,000	22,303,000
Share Information					
Shares Issued	210,024,388	211,110,000	212,160,000	213,140,000	228,777,760
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	210,024,388	211,110,000	212,160,000	213,140,000	228,777,760

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Enbridge Inc. | Balance Sheet

TSX:ENB (MI KEY: 4089108; SPCIQ KEY: 280420)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets (C$000)					
Cash and Cash Equivalents	1,494,000	1,855,000	2,028,000	745,000	480,000
Gross Trade Accounts Receivable	974,000	NA	NA	NA	NA
Trade Accounts Receivable Allowance	46,000	NA	NA	NA	NA
Net Customer and Trade Accounts Receivable	928,000	NA	NA	NA	NA
Other Accounts Receivable	360,000	NA	NA	NA	NA
Accounts Receivable	1,288,000	6,317,000	5,504,000	4,974,000	6,804,000
Unbilled Revenue	2,886,000	NA	NA	NA	NA
Current Inventories	1,233,000	1,205,000	1,249,000	1,707,000	1,528,000
Prepaid Expense	168,000	NA	NA	NA	NA
Current Investments	NA	NA	NA	NA	NA
Short-term Energy Risk-mgmt Assets	353,000	350,000	266,000	265,000	296,000
Deferred Taxes, Current	0	NA	NA	NA	0
Other Current Assets	365,000	175,000	100,000	102,000	107,000
Current Assets	7,787,000	9,902,000	9,147,000	7,793,000	9,215,000
Property, Plant and Equipment (C$000)					
Oil and Gas Gathering Pipeline Systems	34,474,000	NA	NA	NA	47,720,000
Oil and Gas Processing Facilities	NA	NA	NA	NA	NA
Oil and Gas Pipeline Transmission Assets	NA	NA	NA	NA	NA
Plants, Pipelines and Related Assets	34,474,000	NA	NA	NA	47,720,000
Oil and Gas Storage & Terminals	0	NA	NA	NA	1,545,000
Other Oil and Gas Transportation Equipment	25,543,000	NA	NA	NA	33,636,000
Rights of Way	2,067,000	NA	NA	NA	2,538,000
Other Midstream PP&E	9,530,000	NA	NA	NA	12,383,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Midstream Plant, Property & Equipment, Gross	71,614,000	NA	NA	NA	97,822,000
Construction Work in Progress	6,966,000	NA	NA	NA	7,601,000
Other PP&E in Service, Gross	315,000	NA	NA	NA	390,000
PP&E in Service, Gross	78,895,000	NA	NA	NA	105,813,000
Total Accumulated Depreciation	14,611,000	NA	NA	NA	15,102,000
Other Net PP&E	0	NA	NA	NA	0
Net PP&E	64,284,000	99,518,000	99,462,000	96,305,000	90,711,000
Other Assets (C$000)					
Securities - Noncurrent	0	NA	NA	NA	0
Other Investments	614,000	NA	NA	NA	785,000
Investment in Partnerships	6,312,000	NA	NA	NA	16,126,000
Noncurrent Investments	6,926,000	14,703,000	14,558,000	16,572,000	16,911,000
Goodwill	78,000	35,300,000	34,581,000	32,638,000	34,457,000
Intangible Assets other than Goodwill	1,573,000	3,838,000	4,061,000	3,009,000	3,267,000
Total Intangible Assets	1,651,000	39,138,000	38,642,000	35,647,000	37,724,000
Long-term Energy Risk-mgmt Assets	151,000	173,000	181,000	201,000	181,000
Deferred Taxes, Noncurrent	1,170,000	1,202,000	1,129,000	1,067,000	1,090,000
Regulatory Assets	1,921,000	NA	NA	NA	NA
Total Other Assets	1,319,000	5,893,000	5,917,000	5,856,000	6,261,000
Total Assets	85,209,000	170,529,000	169,036,000	163,441,000	162,093,000
Tangible Assets	83,558,000	131,391,000	130,394,000	127,794,000	124,369,000
Current Liabilities (C$000)					
Short-term Debt	351,000	1,669,000	1,977,000	1,424,000	1,444,000
Current Portion of Long-term Debt	4,100,000	4,343,000	2,607,000	2,807,000	2,871,000
Short-term and Current Long-term Debt	4,451,000	6,012,000	4,584,000	4,231,000	4,315,000
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	333,000	628,000	593,000	573,000	634,000
Income Taxes Payable	NA	NA	NA	NA	NA
Customer Security Deposits	52,000	NA	NA	NA	NA
Other Accounts Payable and Accrued Expense	4,970,000	6,767,000	6,292,000	6,178,000	7,167,000
Accounts Payable and Accrued Expense	5,355,000	7,395,000	6,885,000	6,751,000	7,801,000

	2016 FQ4	*2017 FQ1*	*2017 FQ2*	*2017 FQ3*	*2017 FQ4*
Short-term Energy Risk-mgmt Liabilities	1,941,000	1,759,000	1,378,000	1,197,000	1,130,000
Other Current Liabilities	596,000	143,000	43,000	35,000	1,378,000
Current Liabilities	12,343,000	15,309,000	12,890,000	12,214,000	14,624,000
Other Liabilities (C$000)					
Postretirement Benefits	597,000	NA	NA	NA	NA
Deferred Income Tax Liability	6,036,000	14,717,000	14,484,000	14,435,000	9,295,000
Deferred Tax Credit	0	0	0	0	0
Deferred Tax Liability	6,036,000	14,717,000	14,484,000	14,435,000	9,295,000
Non-current Long-term Debt	36,494,000	60,736,000	62,081,000	61,434,000	60,865,000
Long-term Energy Risk-mgmt Liabilities	2,713,000	2,454,000	2,201,000	1,774,000	1,539,000
Regulatory Liabilities	793,000	NA	NA	NA	NA
Total Other Liabilities	878,000	4,555,000	4,738,000	4,870,000	5,971,000
Total Liabilities	59,854,000	97,771,000	96,394,000	94,727,000	92,294,000
Mezzanine (C$000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	3,392,000	3,239,000	3,712,000	3,718,000	4,067,000
Total Mezzanine Level Items	3,392,000	3,239,000	3,712,000	3,718,000	4,067,000
Equity (C$000)					
Total Preferred Equity	7,255,000	7,255,000	7,255,000	7,255,000	7,747,000
Common Equity	14,131,000	52,483,000	51,424,000	50,258,000	50,388,000
Equity Attributable to Parent Company	21,386,000	59,738,000	58,679,000	57,513,000	58,135,000
Noncontrolling Interests	577,000	9,781,000	10,251,000	7,483,000	7,597,000
Total Equity	21,963,000	69,519,000	68,930,000	64,996,000	65,732,000
Tangible Common Equity	12,480,000	13,345,000	12,782,000	14,611,000	12,664,000
Tangible Equity	20,312,000	30,381,000	30,288,000	29,349,000	28,008,000

	2016 FQ4	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4
Capitalization (C$000)					
Equity & Mezzanine Preferred	21,963,000	69,519,000	68,930,000	64,996,000	65,732,000
Total Debt	40,945,000	66,748,000	66,665,000	65,665,000	65,180,000
Total Capitalization, at Book Value	66,300,000	139,506,000	139,307,000	134,379,000	134,979,000
Shares Issued	943,112,225	1,639,000,000	1,645,000,000	1,653,000,000	1,695,000,000
Treasury Shares	0	0	0	0	0
Common Shares Outstanding	943,112,225	1,639,000,000	1,645,000,000	1,653,000,000	1,695,000,000

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Valener Inc. | Balance Sheet

TSX:VNR (MI KEY: 4290080; SPCIQ KEY: 114271781)

Source SNL Financial
Periods 2016Q4, 2017Q1, 2017Q2, 2017Q3, 2017Q4

	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4	2018 FQ1
Fiscal Period Ended	12/31/2016	3/31/2017	6/30/2017	9/30/2017	12/31/2017
Period Restated?	No	No	No	No	No
Restatement Date	NA	NA	NA	NA	NA
Accounting Principle	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP	U.S. GAAP
Current Assets (C$000)					
Cash and Cash Equivalents	1,335	508	641	713	513
Gross Trade Accounts Receivable	0	0	0	0	0
Trade Accounts Receivable Allowance	0	0	0	0	0
Net Customer and Trade Accounts Receivable	0	0	0	0	0
Other Accounts Receivable	14,067	14,374	14,772	15,180	15,252
Accounts Receivable	14,067	14,374	14,772	15,180	15,252
Unbilled Revenue	0	0	0	0	0
Current Inventories	0	0	0	0	0
Prepaid Expense	NA	NA	NA	NA	NA
Current Investments	NA	NA	NA	NA	NA
Short-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Current	0	0	0	0	0
Other Current Assets	33	23	13	3	33
Current Assets	15,435	14,905	15,426	15,896	15,798
Property, Plant and Equipment (C$000)					
Electric PP&E in Service, Gross	0	0	0	0	0
Gas PP&E in Service, Gross	0	0	0	0	0
Other PP&E in Service, Gross	0	0	0	0	0
PP&E in Service, Gross	0	0	0	0	0
Total Accumulated Depreciation	0	0	0	0	0
Net PP&E in Service	0	0	0	0	0
Construction Work in Progress	0	0	0	0	0
Net Nuclear Fuel	0	0	0	0	0

	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4	2018 FQ1
Other Net PP&E	0	0	0	0	0
Net PP&E	0	0	0	0	0
Other Assets (C$000)					
Securities - Noncurrent	0	0	0	0	0
Nuclear Decommissioning Trust	0	0	0	0	0
Other Investments	0	0	0	0	0
Investment in Partnerships	893,846	949,536	930,541	897,966	905,928
Noncurrent Investments	893,846	949,536	930,541	897,966	905,928
Goodwill	0	0	0	0	0
Intangible Assets other than Goodwill	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0
Long-term Energy Risk-mgmt Assets	0	0	0	0	0
Deferred Taxes, Noncurrent	84	0	0	0	0
Regulatory Assets	0	0	0	0	0
Total Other Assets	0	0	0	0	0
Total Assets	909,365	964,441	945,967	913,862	921,726
Tangible Assets	909,365	964,441	945,967	913,862	921,726
Current Liabilities (C$000)					
Short-term Debt	0	0	0	0	0
Current Portion of Long-term Debt	0	0	0	0	0
Short-term and Current Long-term Debt	0	0	0	0	0
Current Portion of Preferred Equity	0	0	0	0	0
Accrued Interest Payable	0	0	0	0	0
Income Taxes Payable	537	7,794	5,671	1,260	2,559
Customer Security Deposits	0	0	0	0	0
Other Accounts Payable and Accrued Expense	12,390	12,455	12,311	12,651	12,915
Accounts Payable and Accrued Expense	12,927	20,249	17,982	13,911	15,474
Short-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Other Current Liabilities	0	0	0	0	0
Current Liabilities	12,927	20,249	17,982	13,911	15,474

	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4	2018 FQ1
Other Liabilities (C$000)					
Postretirement Benefits	0	0	0	0	0
Deferred Income Tax Liability	35,659	37,502	38,402	39,165	40,750
Deferred Tax Credit	0	0	0	0	0
Deferred Tax Liability	35,659	37,502	38,402	39,165	40,750
Non-current Long-term Debt	90,250	116,717	112,251	103,759	102,281
Long-term Energy Risk-mgmt Liabilities	0	0	0	0	0
Regulatory Liabilities	0	0	0	0	0
Total Other Liabilities	0	0	0	0	0
Total Liabilities	138,836	174,468	168,635	156,835	158,505
Mezzanine (C$000)					
Minority Interest	0	0	0	0	0
Subsidiary Preferred	0	0	0	0	0
Total Minority Interest	0	0	0	0	0
Other Mezzanine Items	0	0	0	0	0
Total Mezzanine Level Items	0	0	0	0	0
Equity (C$000)					
Total Preferred Equity	97,480	97,480	97,480	97,480	97,480
Common Equity	673,049	692,493	679,852	659,547	665,741
Equity Attributable to Parent Company	770,529	789,973	777,332	757,027	763,221
Noncontrolling Interests	0	0	0	0	0
Total Equity	770,529	789,973	777,332	757,027	763,221
Tangible Common Equity	673,049	692,493	679,852	659,547	665,741
Tangible Equity	770,529	789,973	777,332	757,027	763,221
Capitalization (C$000)					
Equity & Mezzanine Preferred	770,529	789,973	777,332	757,027	763,221
Total Debt	90,250	116,717	112,251	103,759	102,281

	2017 FQ1	2017 FQ2	2017 FQ3	2017 FQ4	2018 FQ1
Total Capitalization, at Book Value	860,779	906,690	889,583	860,786	865,502
Share Information					
Shares Issued	38,691,000	38,752,159	38,812,058	38,877,164	38,946,614
Treasury Shares	0	0	0	0	0
Common Shares Outstanding (actual)	38,691,000	38,752,159	38,812,058	38,877,164	38,946,614

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Allete, Inc. (ALE)
(Real Time Quote from BATS)

$72.25 USD

+0.42 (0.59%)

Updated Mar 29, 2018 04:02 PM ET

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Zacks Rank:
4-Sell 4

Style Scores:
D Value | C Growth | C Momentum | D VGM

Industry Rank:
Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

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Allete, Inc. (ALE) Quote Overview » Estimates » Allete, Inc. (ALE) Detailed Estimates

Detailed Estimates

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Estimates

Next Report Date	5/3/18	Earnings ESP	3.03%
Current Quarter	0.99	Current Year	3.34
EPS Last Quarter	0.75	Next Year	3.55
Last EPS Surprise	-17.33%	EPS (TTM)	3.35
ABR	2.60	P/E (F1)	21.61

Growth Estimates	ALE	IND	S&P
Current Qtr (03/2018)	2.06	-20.83	29.93
Next Qtr (06/2018)	2.78	-15.01	28.38
Current Year (12/2018)	4.70	4.20	42.42
Next Year (12/2019)	6.29	11.00	9.36
Past 5 Years	3.90	5.00	2.80
Next 5 Years	6.60	7.00	NA
PE	21.61	17.70	17.45
PEG Ratio	3.27	2.53	NA

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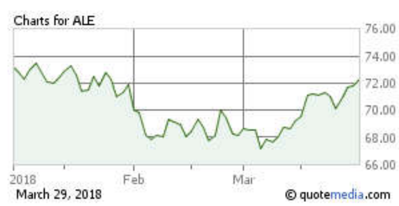
Research for ALE

Chart for ALE



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	Monday	In a Week	In a Month	In 3 Months
ALE Allete, Inc.				

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Premium Research for ALE

Zacks Rank	Sell 4
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)
Style Scores	

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D Value | C Growth | C Momentum | D VGM

Earnings ESP	3.03%
Research Report for ALE	Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	354.77M	342.22M	907.37M	1.43B
# of Estimates	1	1	2	1
High Estimate	354.77M	342.22M	1.41B	1.43B
Low Estimate	354.77M	342.22M	403.80M	1.43B
Year ago Sales	365.60M	353.30M	1.42B	907.37M
Year over Year Growth Est.	-2.96%	-3.14%	-36.07%	57.60%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.99	0.74	3.34	3.55
# of Estimates	3	2	3	2
Most Recent Consensus	0.98	0.76	3.40	3.68
High Estimate	1.02	0.76	3.40	3.68
Low Estimate	0.95	0.72	3.23	3.41
Year ago EPS	0.97	0.72	3.19	3.34
Year over Year Growth Est.	2.06%	2.78%	4.70%	6.04%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	1	0	2
Up Last 60 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0
Down Last 60 Days	0	0	3	1

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.99	0.74	3.34	3.55
7 Days Ago	0.99	0.74	3.34	3.55
30 Days Ago	0.98	0.73	3.36	3.43
60 Days Ago	NA	NA	3.54	3.68
90 Days Ago	NA	NA	3.50	3.65

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	1.02	0.72	3.23	3.55
Zacks Consensus Estimate	0.99	0.74	3.34	3.55
Earnings ESP	3.03%	-2.70%	-3.39%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.62	1.04	0.72	0.97	NA
Estimate	0.75	0.95	0.57	0.95	NA
Difference	-0.13	0.09	0.15	0.02	0.03
Surprise	-17.33%	9.47%	26.32%	2.11%	5.14%

Annual Estimates By Analyst

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Alliant Energy Corporation (LNT)

(Real Time Quote from BATS)

$40.86 USD

+0.24 (0.59%)

Updated Mar 29, 2018 04:03 PM ET

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Zacks Rank:
3-Hold 3

Style Scores:
D Value | D Growth | D Momentum | F VGM

Industry Rank:
Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

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Alliant Energy Corporation (LNT) Quote Overview » Estimates » Alliant Energy Corporation (LNT) Detailed Estimates

Detailed Estimates

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Estimates

Next Report Date	5/2/18	Earnings ESP	0.00%
Current Quarter	0.49	Current Year	2.11
EPS Last Quarter	0.38	Next Year	2.23
Last EPS Surprise	-13.16%	EPS (TTM)	1.92
ABR	3.00	P/E (F1)	19.36

Growth Estimates	LNT	IND	S&P
Current Qtr (03/2018)	13.95	-20.83	29.93
Next Qtr (06/2018)	9.76	-15.01	28.38
Current Year (12/2018)	9.33	4.20	42.42
Next Year (12/2019)	5.69	11.00	9.36
Past 5 Years	5.00	5.00	2.80
Next 5 Years	5.30	7.00	NA
PE	19.36	17.70	17.45
PEG Ratio	3.66	2.53	NA

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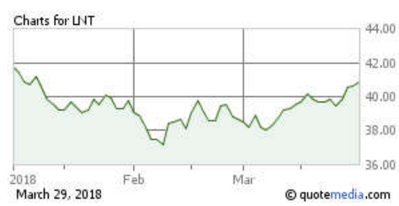
Research for LNT

Chart for LNT



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	Monday	In a Week	In a Month	In 3 Months
LNT Alliant Energy ...				

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Premium Research for LNT

Zacks Rank	**Hold** 3
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)
Style Scores	

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Earnings ESP	0.00%
Research Reports for LNT	Analyst | Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	3.60B	3.75B
# of Estimates	NA	NA	1	1
High Estimate	NA	NA	3.60B	3.75B
Low Estimate	NA	NA	3.60B	3.75B
Year ago Sales	853.90M	765.30M	3.38B	3.60B
Year over Year Growth Est.	NA	NA	6.38%	4.20%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.49	0.45	2.11	2.23
# of Estimates	2	1	4	4
Most Recent Consensus	0.50	0.45	2.10	2.20
High Estimate	0.50	0.45	2.12	2.25
Low Estimate	0.47	0.45	2.10	2.20
Year ago EPS	0.43	0.41	1.93	2.11
Year over Year Growth Est.	13.95%	9.76%	9.33%	5.45%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	0	0	1	0

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.49	0.45	2.11	2.23
7 Days Ago	0.49	0.45	2.11	2.23
30 Days Ago	0.49	0.45	2.11	2.23
60 Days Ago	NA	NA	2.12	2.20
90 Days Ago	NA	NA	2.13	2.20

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.49	0.45	2.10	2.20
Zacks Consensus Estimate	0.49	0.45	2.11	2.23
Earnings ESP	0.00%	0.00%	-0.47%	-1.12%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.33	0.75	0.41	0.43	NA
Estimate	0.38	0.88	0.39	0.45	NA
Difference	-0.05	-0.13	0.02	-0.02	-0.05
Surprise	-13.16%	-14.77%	5.13%	-4.44%	-6.81%

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Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

American Electric Power Company, Inc. (AEP)

(Real Time Quote from BATS)

$68.59 USD

-0.07 (-0.10%)

Updated Mar 29, 2018 04:03 PM ET

Add to portfolio | Trades from $3

Zacks Rank:
3-Hold 3

Style Scores:
C Value | D Growth | F Momentum | D VGM

Industry Rank:
Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

American Electric Power Company, Inc. (AEP) Quote Overview » Estimates » American Electric Power Company, Inc. (AEP) Detailed Estimates

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	4/26/18	Earnings ESP	-0.91%
Current Quarter	0.99	Current Year	3.89
EPS Last Quarter	0.81	Next Year	4.12
Last EPS Surprise	4.94%	EPS (TTM)	3.66
ABR	1.57	P/E (F1)	17.65

Growth Estimates	AEP	IND	S&P
Current Qtr (03/2018)	3.13	-20.83	29.93
Next Qtr (06/2018)	9.33	-15.01	28.38
Current Year (12/2018)	5.71	4.20	42.42
Next Year (12/2019)	5.91	11.00	9.36
Past 5 Years	3.20	5.00	2.80
Next 5 Years	5.40	7.00	NA
PE	17.65	17.70	17.45
PEG Ratio	3.28	2.53	NA

Learn More About Estimate Research

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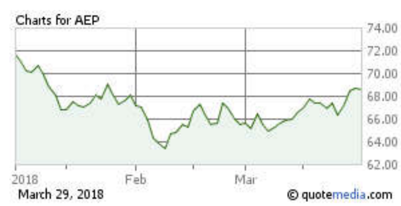
See Earnings Report Transcript

Research for AEP

Chart for AEP



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	Monday	In a Week	In a Month	In 3 Months
AEP American Electr...				

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Premium Research for AEP

Zacks Rank	**Hold** 3
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)

Access Zacks Data Feed

Style Scores	C Value | D Growth | F Momentum | D VGM
Earnings ESP	-0.91%
Research Reports for AEP	Analyst | Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	3.73B	NA	15.49B	15.86B
# of Estimates	1	NA	5	5
High Estimate	3.73B	NA	16.25B	16.55B
Low Estimate	3.73B	NA	14.21B	14.55B
Year ago Sales	3.93B	3.60B	15.44B	15.49B
Year over Year Growth Est.	-5.22%	NA	0.31%	2.43%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.99	0.82	3.89	4.12
# of Estimates	5	3	9	7
Most Recent Consensus	1.00	0.80	3.90	4.15
High Estimate	1.01	0.87	3.92	4.21
Low Estimate	0.97	0.79	3.84	4.02
Year ago EPS	0.96	0.75	3.68	3.89
Year over Year Growth Est.	3.13%	9.33%	5.71%	6.03%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	1	1	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	0	1	0
Down Last 60 Days	1	0	1	1

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.99	0.82	3.89	4.12
7 Days Ago	0.99	0.82	3.89	4.12
30 Days Ago	1.00	0.82	3.89	4.12
60 Days Ago	1.00	0.82	3.89	4.12
90 Days Ago	1.00	0.83	3.89	4.13

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.99	0.82	3.92	4.16
Zacks Consensus Estimate	0.99	0.82	3.89	4.12
Earnings ESP	-0.91%	0.00%	0.86%	0.94%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.85	1.10	0.75	0.96	NA
Estimate	0.81	1.15	0.82	0.97	NA
Difference	0.04	-0.05	-0.07	-0.01	-0.02
Surprise	4.94%	-4.35%	-8.54%	-1.03%	-2.25%

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Duke Energy Corporation (DUK)

(Real Time Quote from BATS)

$77.47 USD

+0.05 (0.07%)

Updated Mar 29, 2018 04:04 PM ET

Add to portfolio | Trades from $3

Zacks Rank: 3-Hold 3

Style Scores: C Value | D Growth | C Momentum | D VGM

Industry Rank: Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

Duke Energy Corporation (DUK) Quote Overview » Estimates » Duke Energy Corporation (DUK) Detailed Estimates

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	5/8/18	Earnings ESP	4.61%
Current Quarter	1.13	Current Year	4.70
EPS Last Quarter	0.91	Next Year	4.95
Last EPS Surprise	3.30%	EPS (TTM)	4.58
ABR	2.82	P/E (F1)	16.49

Growth Estimates	DUK	IND	S&P
Current Qtr (03/2018)	8.65	-20.83	29.93
Next Qtr (06/2018)	2.97	-15.01	28.38
Current Year (12/2018)	2.84	4.20	42.42
Next Year (12/2019)	5.32	11.00	9.36
Past 5 Years	1.00	5.00	2.80
Next 5 Years	3.70	7.00	NA
PE	16.49	17.70	17.45
PEG Ratio	4.46	2.53	NA

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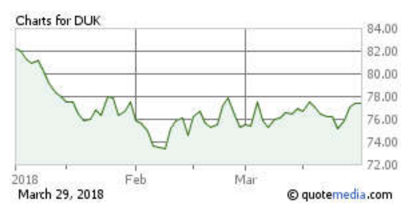
Research for DUK

Chart for DUK



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DUK Duke Energy Cor...				

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Premium Research for DUK

Zacks Rank	Hold 3
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)
Style Scores	

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C Value | D Growth | C Momentum | D VGM

Earnings ESP	4.61%
Research Reports for DUK	Analyst | Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	5.74B	5.50B	23.51B	24.13B
# of Estimates	1	1	4	4
High Estimate	5.74B	5.50B	23.81B	24.29B
Low Estimate	5.74B	5.50B	23.31B	23.98B
Year ago Sales	5.73B	5.56B	23.62B	23.51B
Year over Year Growth Est.	0.24%	-0.98%	-0.47%	2.66%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	1.13	1.04	4.70	4.95
# of Estimates	5	4	9	6
Most Recent Consensus	1.05	1.03	4.70	4.95
High Estimate	1.27	1.09	4.75	5.00
Low Estimate	1.05	0.98	4.65	4.85
Year ago EPS	1.04	1.01	4.57	4.70
Year over Year Growth Est.	8.65%	2.97%	2.84%	5.31%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	1	0	0	0
Up Last 30 Days	0	0	0	1
Up Last 60 Days	0	0	0	1
Down Last 7 Days	0	1	1	1
Down Last 30 Days	1	1	3	1
Down Last 60 Days	2	2	9	3

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	1.13	1.04	4.70	4.95
7 Days Ago	1.13	1.04	4.70	4.95
30 Days Ago	1.14	1.07	4.73	4.95
60 Days Ago	1.21	1.11	4.82	4.99
90 Days Ago	1.20	1.11	4.83	5.05

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	1.18	1.04	4.69	4.92
Zacks Consensus Estimate	1.13	1.04	4.70	4.95
Earnings ESP	4.61%	0.00%	-0.30%	-0.57%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.94	1.59	1.01	1.04	NA
Estimate	0.91	1.56	1.02	1.06	NA
Difference	0.03	0.03	-0.01	-0.02	0.01
Surprise	3.30%	1.92%	-0.98%	-1.89%	0.59%

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Edison International (EIX)

(Real Time Quote from BATS)

$63.66 USD

+0.59 (0.94%)

Updated Mar 29, 2018 04:01 PM ET

Add to port | Trades from $3

Zacks Rank: 3-Hold 3

Style Scores: C Value | D Growth | F Momentum | D VGM

Industry Rank: Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

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Edison International (EIX) Quote Overview » Estimates » Edison International (EIX) Detailed Estimates

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	5/7/18	Earnings ESP	-5.12%
Current Quarter	0.92	Current Year	4.13
EPS Last Quarter	0.93	Next Year	4.55
Last EPS Surprise	18.28%	EPS (TTM)	4.48
ABR	2.45	P/E (F1)	15.41

Growth Estimates	EIX	IND	S&P
Current Qtr (03/2018)	-16.36	-20.83	29.93
Next Qtr (06/2018)	-4.71	-15.01	28.38
Current Year (12/2018)	-8.22	4.20	42.42
Next Year (12/2019)	10.17	11.00	9.36
Past 5 Years	4.20	5.00	2.80
Next 5 Years	5.50	7.00	NA
PE	15.41	17.70	17.45
PEG Ratio	2.78	2.53	NA

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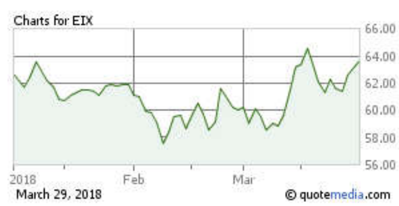
See Earnings Report Transcript

Research for EIX

Chart for EIX



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	Monday	In a Week	In a Month	In 3 Months
EIX Edison Internat...				

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Premium Research for EIX

Zacks Rank	Hold 3
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)
Style Scores	

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C Value | D Growth | F Momentum | D VGM

Earnings ESP	-5.12%
Research Reports for EIX	Analyst | Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	2.46B	2.95B	12.60B	12.98B
# of Estimates	1	1	5	5
High Estimate	2.46B	2.95B	13.19B	13.58B
Low Estimate	2.46B	2.95B	12.25B	12.70B
Year ago Sales	2.46B	2.97B	12.32B	12.60B
Year over Year Growth Est.	-0.32%	-0.44%	2.28%	3.04%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.92	0.81	4.13	4.55
# of Estimates	5	4	7	7
Most Recent Consensus	1.00	0.88	4.13	4.50
High Estimate	1.10	0.88	4.25	4.61
Low Estimate	0.71	0.72	3.86	4.50
Year ago EPS	1.10	0.85	4.50	4.13
Year over Year Growth Est.	-16.36%	-4.71%	-8.22%	10.21%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	1	1
Down Last 7 Days	0	1	1	1
Down Last 30 Days	2	2	4	3
Down Last 60 Days	2	2	6	3

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.92	0.81	4.13	4.55
7 Days Ago	0.92	0.82	4.16	4.56
30 Days Ago	0.95	0.84	4.23	4.58
60 Days Ago	1.01	0.89	4.26	4.62
90 Days Ago	1.01	0.89	4.27	4.65

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.88	0.81	4.10	4.55
Zacks Consensus Estimate	0.92	0.81	4.13	4.55
Earnings ESP	-5.12%	0.21%	-0.66%	-0.01%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	1.10	1.43	0.85	1.10	NA
Estimate	0.93	1.33	0.85	0.89	NA
Difference	0.17	0.10	0.00	0.21	0.12
Surprise	18.28%	7.52%	0.00%	23.60%	12.35%

Quarterly Estimates By Analyst

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Annual Estimates By Analyst

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Eversource Energy (ES)

(Real Time Quote from BATS)

$58.92 USD

+0.45 (0.77%)

Updated Mar 29, 2018 04:02 PM ET

Zacks Rank: 4-Sell 4

Style Scores: C Value | B Growth | D Momentum | C VGM

Industry Rank: Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

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Eversource Energy (ES) Quote Overview » Estimates » Eversource Energy (ES) Detailed Estimates

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	5/2/18	Earnings ESP	0.86%
Current Quarter	0.87	Current Year	3.27
EPS Last Quarter	0.76	Next Year	3.47
Last EPS Surprise	-1.32%	EPS (TTM)	3.11
ABR	2.73	P/E (F1)	18.00

Growth Estimates	ES	IND	S&P
Current Qtr (03/2018)	6.10	-20.83	29.93
Next Qtr (06/2018)	2.78	-15.01	28.38
Current Year (12/2018)	5.14	4.20	42.42
Next Year (12/2019)	6.12	11.00	9.36
Past 5 Years	5.30	5.00	2.80
Next 5 Years	5.80	7.00	NA
PE	18.00	17.70	17.45
PEG Ratio	3.13	2.53	NA

Learn More About Estimate Research

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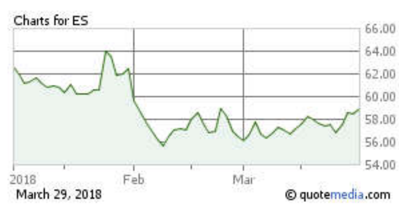
Research for ES

Chart for ES



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	Monday	In a Week	In a Month	In 3 Months
ES Eversource Ener...				

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Premium Research for ES

Zacks Rank	Sell 4
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)
Style Scores	

Access Zacks Data Feed

C Value | B Growth | D Momentum | C VGM

Earnings ESP	0.86%
Research Reports for ES	Analyst | Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	2.18B	1.83B	7.88B	8.08B
# of Estimates	1	1	4	4
High Estimate	2.18B	1.83B	8.11B	8.40B
Low Estimate	2.18B	1.83B	7.67B	7.87B
Year ago Sales	2.11B	1.76B	7.75B	7.88B
Year over Year Growth Est.	3.45%	3.73%	1.63%	2.52%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.87	0.74	3.27	3.47
# of Estimates	4	4	8	7
Most Recent Consensus	0.86	0.72	3.25	3.48
High Estimate	0.88	0.76	3.38	3.64
Low Estimate	0.86	0.72	3.22	3.40
Year ago EPS	0.82	0.72	3.11	3.27
Year over Year Growth Est.	6.10%	2.78%	5.14%	6.04%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	1	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	2	0
Down Last 60 Days	0	0	6	4

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.87	0.74	3.27	3.47
7 Days Ago	0.87	0.74	3.27	3.47
30 Days Ago	0.87	0.74	3.29	3.47
60 Days Ago	0.88	0.73	3.33	3.57
90 Days Ago	0.88	0.74	3.33	3.54

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.88	0.76	3.26	3.43
Zacks Consensus Estimate	0.87	0.74	3.27	3.47
Earnings ESP	0.86%	2.70%	-0.52%	-1.19%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.75	0.82	0.72	0.82	NA
Estimate	0.76	0.84	0.68	0.83	NA
Difference	-0.01	-0.02	0.04	-0.01	0.00
Surprise	-1.32%	-2.38%	5.88%	-1.20%	0.25%

Quarterly Estimates By Analyst

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OGE Energy Corporation (OGE)

(Real Time Quote from BATS)

$32.77 USD

+0.44 (1.36%)

Updated Mar 29, 2018 04:06 PM ET

Add to portfolio Trades from $3

Zacks Rank: 3-Hold 3

Style Scores: C Value | D Growth | C Momentum | D VGM

Industry Rank: Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

OGE Energy Corporation (OGE) Quote Overview » Estimates » OGE Energy Corporation (OGE) Detailed Estimates

View All Zacks #1 Ranked Stocks

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	5/3/18	Earnings ESP	0.00%
Current Quarter	0.16	Current Year	2.00
EPS Last Quarter	0.28	Next Year	2.14
Last EPS Surprise	7.14%	EPS (TTM)	1.92
ABR	2.33	P/E (F1)	16.41

Growth Estimates	OGE	IND	S&P
Current Qtr (03/2018)	-11.11	-20.83	29.93
Next Qtr (06/2018)	1.92	-15.01	28.38
Current Year (12/2018)	4.17	4.20	42.42
Next Year (12/2019)	7.00	11.00	9.36
Past 5 Years	1.10	5.00	2.80
Next 5 Years	6.00	7.00	NA
PE	16.41	17.70	17.45
PEG Ratio	2.75	2.53	NA

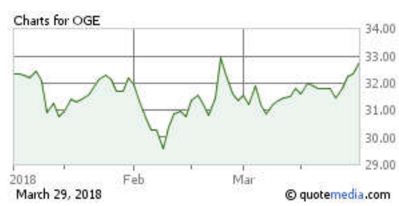
Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Research for OGE

Chart for OGE



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	Monday	In a Week	In a Month	In 3 Months
OGE Oge Energy Corp…				

Predicting constitutes acceptance of PredictWallStreet's terms of use.

Premium Research for OGE

Zacks Rank	Hold 3
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)
Style Scores	

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Earnings ESP	0.00%
Research Reports for OGE	Analyst | Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	NA	NA
# of Estimates	NA	NA	NA	NA
High Estimate	NA	NA	NA	NA
Low Estimate	NA	NA	NA	NA
Year ago Sales	456.00M	586.40M	2.26B	NA
Year over Year Growth Est.	NA	NA	NA	NA

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.16	0.53	2.00	2.14
# of Estimates	1	1	4	2
Most Recent Consensus	0.16	0.53	1.98	2.14
High Estimate	0.16	0.53	2.01	2.15
Low Estimate	0.16	0.53	1.98	2.12
Year ago EPS	0.18	0.52	1.92	2.00
Year over Year Growth Est.	-11.11%	1.92%	4.17%	6.88%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	1	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.16	0.53	2.00	2.14
7 Days Ago	0.16	0.53	2.00	2.14
30 Days Ago	0.16	0.53	2.00	2.14
60 Days Ago	NA	NA	1.98	NA
90 Days Ago	NA	NA	1.99	NA

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.16	0.53	2.00	2.14
Zacks Consensus Estimate	0.16	0.53	2.00	2.14
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.30	0.92	0.52	0.18	NA
Estimate	0.28	0.93	0.47	0.17	NA
Difference	0.02	-0.01	0.05	0.01	0.02
Surprise	7.14%	-1.08%	10.64%	5.88%	5.65%

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Pinnacle West Capital Corporation (PNW)

(Real Time Quote from BATS)

$79.80 USD

+0.33 (0.42%)

Updated Mar 29, 2018 04:05 PM ET

Add to port Trades from $3

Zacks Rank: 3-Hold 3

Style Scores: C Value | D Growth | D Momentum | D VGM

Industry Rank: Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

Pinnacle West Capital Corporation (PNW) Quote Overview » Estimates » Pinnacle West Capital Corporation (PNW) Detailed Estimates

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	5/1/18	Earnings ESP	13.33%
Current Quarter	0.15	Current Year	4.46
EPS Last Quarter	0.10	Next Year	4.67
Last EPS Surprise	90.00%	EPS (TTM)	4.35
ABR	3.00	P/E (F1)	17.91

Growth Estimates	PNW	IND	S&P
Current Qtr (03/2018)	-28.57	-20.83	29.93
Next Qtr (06/2018)	-4.70	-15.01	28.38
Current Year (12/2018)	2.53	4.20	42.42
Next Year (12/2019)	4.71	11.00	9.36
Past 5 Years	5.10	5.00	2.80
Next 5 Years	3.00	7.00	NA
PE	17.91	17.70	17.45
PEG Ratio	6.03	2.53	NA

Learn More About Estimate Research

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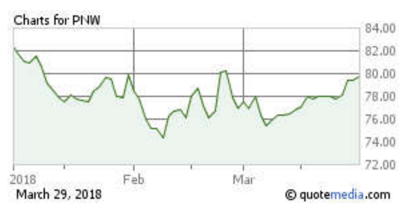
Research for PNW

Chart for PNW



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	Monday	In a Week	In a Month	In 3 Months
PNW Pinnacle West C...				

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Premium Research for PNW

Zacks Rank	Hold 3
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)

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Style Scores	C Value | D Growth | D Momentum | D VGM
Earnings ESP	13.33%
Research Reports for PNW	Analyst | Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	3.60B	3.69B
# of Estimates	NA	NA	2	2
High Estimate	NA	NA	3.64B	3.77B
Low Estimate	NA	NA	3.56B	3.62B
Year ago Sales	677.73M	944.59M	3.57B	3.60B
Year over Year Growth Est.	NA	NA	0.95%	2.53%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.15	1.42	4.46	4.67
# of Estimates	4	3	5	4
Most Recent Consensus	0.15	1.25	4.45	4.65
High Estimate	0.23	1.54	4.48	4.75
Low Estimate	0.05	1.25	4.45	4.58
Year ago EPS	0.21	1.49	4.35	4.46
Year over Year Growth Est.	-28.57%	-4.70%	2.53%	4.85%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	1	0
Up Last 60 Days	1	1	4	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	0	0	0
Down Last 60 Days	1	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.15	1.42	4.46	4.67
7 Days Ago	0.15	1.42	4.46	4.67
30 Days Ago	0.17	1.42	4.45	4.67
60 Days Ago	0.24	1.49	4.40	4.73
90 Days Ago	0.24	1.49	4.40	4.73

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.17	1.46	4.45	4.71
Zacks Consensus Estimate	0.15	1.42	4.46	4.67
Earnings ESP	13.33%	3.06%	-0.14%	0.80%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.19	2.46	1.49	0.21	NA
Estimate	0.10	2.33	1.16	0.15	NA
Difference	0.09	0.13	0.33	0.06	0.15
Surprise	90.00%	5.58%	28.45%	40.00%	41.01%

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PNM Resources, Inc. (Holding Co.) (PNM)

(Real Time Quote from BATS)

$38.25 USD

-0.05 (-0.13%)

Updated Mar 29, 2018 04:00 PM ET

Zacks Rank: 2-Buy

Style Scores: F Value | F Growth | B Momentum | F VGM

Industry Rank: Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	*BMO 4/27/18	Earnings ESP	-10.00%
Current Quarter	0.23	Current Year	1.87
EPS Last Quarter	0.19	Next Year	2.09
Last EPS Surprise	26.32%	EPS (TTM)	1.94
ABR	3.50	P/E (F1)	20.50

*BMO = Before Market Open *AMC = After Market Close

Growth Estimates	PNM	IND	S&P
Current Qtr (03/2018)	-17.86	-20.83	29.93
Next Qtr (06/2018)	2.04	-15.01	28.38
Current Year (12/2018)	-3.61	4.20	42.42
Next Year (12/2019)	11.76	11.00	9.36
Past 5 Years	8.80	5.00	2.80
Next 5 Years	5.40	7.00	NA
PE	20.50	17.70	17.45
PEG Ratio	3.82	2.53	NA

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See Earnings Report Transcript

Premium Research for PNM

Zacks Rank	Buy 2
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)

Research for PNM

Chart for PNM

Interactive Chart | Fundamental Charts

Style Scores	F Value | F Growth | B Momentum | F VGM
Earnings ESP	-10.00%
Research Report for PNM	Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	1.46B	1.52B
# of Estimates	NA	NA	2	2
High Estimate	NA	NA	1.48B	1.53B
Low Estimate	NA	NA	1.45B	1.52B
Year ago Sales	330.18M	362.32M	1.45B	1.46B
Year over Year Growth Est.	NA	NA	1.21%	4.10%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.23	0.50	1.87	2.09
# of Estimates	3	2	5	5
Most Recent Consensus	0.21	0.50	1.86	2.10
High Estimate	0.28	0.50	1.89	2.10
Low Estimate	0.21	0.50	1.85	2.05
Year ago EPS	0.28	0.49	1.94	1.87
Year over Year Growth Est.	-17.86%	2.04%	-3.61%	11.76%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	1	0
Up Last 30 Days	0	0	1	0
Up Last 60 Days	1	1	5	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.23	0.50	1.87	2.09
7 Days Ago	0.23	0.50	1.83	2.08
30 Days Ago	0.23	0.50	1.83	2.08
60 Days Ago	0.19	0.47	1.74	2.09
90 Days Ago	0.20	0.46	1.74	2.08

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.21	0.50	1.87	2.09
Zacks Consensus Estimate	0.23	0.50	1.87	2.09
Earnings ESP	-10.00%	0.00%	0.21%	0.35%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.24	0.93	0.49	0.28	NA
Estimate	0.19	0.85	0.45	0.25	NA
Difference	0.05	0.08	0.04	0.03	0.05
Surprise	26.32%	9.41%	8.89%	12.00%	14.16%

Quarterly Estimates By Analyst

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Annual Estimates By Analyst

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Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

Southern Company (The) (SO)

(Real Time Quote from BATS)

$44.66 USD

+0.02 (0.05%)

Updated Mar 29, 2018 04:00 PM ET

Add to portfolio Trades from $3

Zacks Rank:
4-Sell 4

Style Scores:
D Value | C Growth | D Momentum | D VGM

Industry Rank:
Bottom 30%(185 out of 265)

Industry: Utility - Electric Power

Southern Company (The) (SO) Quote Overview » Estimates » Southern Company (The) (SO) Detailed Estimates

View All Zacks #1 Ranked Stocks

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	5/2/18	Earnings ESP	-5.71%
Current Quarter	0.81	Current Year	2.90
EPS Last Quarter	0.46	Next Year	3.05
Last EPS Surprise	10.87%	EPS (TTM)	3.02
ABR	2.95	P/E (F1)	15.38

Growth Estimates	SO	IND	S&P
Current Qtr (03/2018)	22.73	-20.83	29.93
Next Qtr (06/2018)	-10.96	-15.01	28.38
Current Year (12/2018)	-3.97	4.20	42.42
Next Year (12/2019)	5.17	11.00	9.36
Past 5 Years	2.60	5.00	2.80
Next 5 Years	4.50	7.00	NA
PE	15.38	17.70	17.45
PEG Ratio	3.42	2.53	NA

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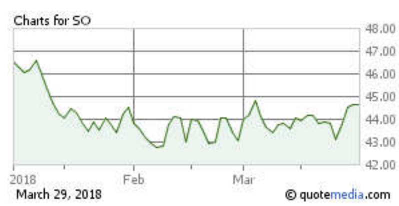
Research for SO

Chart for SO



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Predict to see real-time community sentiment

	Monday	In a Week	In a Month	In 3 Months
SO Southern Compan…				

Predicting constitutes acceptance of PredictWallStreet's terms of use.

Premium Research for SO

Zacks Rank	**Sell** 4
Zacks Industry Rank	Bottom 30%(185 out of 265)
Zacks Sector Rank	Bottom 25% (12 out of 16)
Style Scores	

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D Value | C Growth | D Momentum | D VGM

Earnings ESP	-5.71%
Research Reports for SO	Analyst | Snapshot

(= Change in last 30 days)

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Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	5.84B	NA	22.90B	23.49B
# of Estimates	1	NA	5	5
High Estimate	5.84B	NA	24.15B	24.97B
Low Estimate	5.84B	NA	22.28B	22.49B
Year ago Sales	5.77B	5.43B	23.03B	22.90B
Year over Year Growth Est.	1.27%	NA	-0.57%	2.56%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.81	0.65	2.90	3.05
# of Estimates	5	3	9	6
Most Recent Consensus	0.84	0.57	2.90	3.05
High Estimate	0.85	0.74	3.00	3.15
Low Estimate	0.74	0.57	2.84	2.97
Year ago EPS	0.66	0.73	3.02	2.90
Year over Year Growth Est.	22.73%	-10.96%	-3.97%	5.06%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	1	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	2	2
Down Last 60 Days	0	1	8	4

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.81	0.65	2.90	3.05
7 Days Ago	0.81	0.65	2.90	3.05
30 Days Ago	0.82	0.65	2.93	3.07
60 Days Ago	0.71	0.74	3.00	3.11
90 Days Ago	0.72	0.74	3.01	3.13

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.76	0.65	2.87	3.03
Zacks Consensus Estimate	0.81	0.65	2.90	3.05
Earnings ESP	-5.71%	0.00%	-1.15%	-0.82%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.51	1.12	0.73	0.66	NA
Estimate	0.46	1.08	0.71	0.58	NA
Difference	0.05	0.04	0.02	0.08	0.05
Surprise	10.87%	3.70%	2.82%	13.79%	7.80%

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +25% per year. These returns cover a period from 1988-2017. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zack Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

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Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

Our Research. Your Success.

Enbridge Inc (ENB)
(Real Time Quote from BATS)

$31.47 USD
+1.11 (3.66%)
Updated Mar 29, 2018 04:04 PM ET

Add to port Trades from $3

Zacks Rank:
4-Sell 4

Style Scores:
C Value | C Growth | F Momentum | C VGM

Industry Rank:
Bottom 9%(241 out of 265)

Industry: Oil and Gas - Production and Pipelines

Enbridge Inc (ENB) Quote Overview » Estimates » Enbridge Inc (ENB) Detailed Estimates

Detailed Estimates

Enter Symbol

Estimates

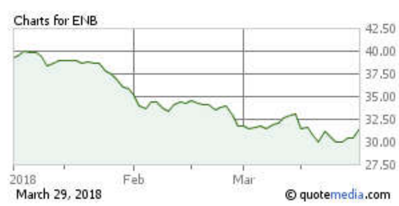
Next Report Date	5/10/18	Earnings ESP	0.00%
Current Quarter	0.47	Current Year	1.75
EPS Last Quarter	0.42	Next Year	1.92
Last EPS Surprise	14.29%	EPS (TTM)	1.60
ABR	2.29	P/E (F1)	17.98

Growth Estimates	ENB	IND	S&P
Current Qtr (03/2018)	9.30	-3.18	29.93
Next Qtr (06/2018)	30.00	-0.73	28.38
Current Year (12/2018)	13.64	11.40	42.42
Next Year (12/2019)	9.71	17.40	9.36
Past 5 Years	0.30	1.10	2.80
Next 5 Years	9.00	8.00	NA
PE	17.98	20.10	17.45
PEG Ratio	2.00	2.51	NA

Learn More About Estimate Research
See Brokerage Recommendations
See Earnings Report Transcript

Research for ENB

Chart for ENB



Interactive Chart | Fundamental Charts

Predict to see real-time community sentiment

	Monday	In a Week	In a Month	In 3 Months
ENB Enbridge Inc				

Predicting constitutes acceptance of PredictWallStreet's terms of use.

Premium Research for ENB

Zacks Rank	Sell 4
Zacks Industry Rank	Bottom 9%(241 out of 265)
Zacks Sector Rank	Bottom 0% (16 out of 16)
Style Scores	

C Value | C Growth | F Momentum | C VGM

Earnings ESP	0.00%
Research Reports for ENB	Analyst | Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Sales Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	10.29B	9.59B	46.28B	49.10B
# of Estimates	1	1	3	3
High Estimate	10.29B	9.59B	61.59B	67.06B
Low Estimate	10.29B	9.59B	36.14B	36.30B
Year ago Sales	8.42B	8.26B	36.06B	46.28B
Year over Year Growth Est.	22.23%	16.14%	28.35%	6.09%

Earnings Estimates

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.47	0.39	1.75	1.92
# of Estimates	3	2	6	6
Most Recent Consensus	0.47	0.41	1.74	1.88
High Estimate	0.48	0.41	1.85	2.15
Low Estimate	0.47	0.36	1.64	1.81
Year ago EPS	0.43	0.30	1.54	1.75
Year over Year Growth Est.	9.30%	30.00%	13.64%	9.43%

Agreement - Estimate Revisions

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	1
Up Last 60 Days	1	1	1	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	2	2	3	2
Down Last 60 Days	1	1	2	2

Magnitude - Consensus Estimate Trend

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.47	0.39	1.75	1.92
7 Days Ago	0.47	0.39	1.75	1.92
30 Days Ago	0.48	0.40	1.78	1.92
60 Days Ago	0.48	0.40	1.81	1.92
90 Days Ago	0.48	0.39	1.82	2.01

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (3/2018)	Next Qtr (6/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.47	0.39	1.76	1.96
Zacks Consensus Estimate	0.47	0.39	1.75	1.92
Earnings ESP	0.00%	0.00%	0.57%	2.22%

Surprise - Reported Earnings History

	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Quarter Ending (3/2017)	Average Surprise
Reported	0.48	0.39	0.30	0.43	NA
Estimate	0.42	0.36	0.35	0.52	NA
Difference	0.06	0.03	-0.05	-0.09	-0.01
Surprise	14.29%	8.33%	-14.29%	-17.31%	-2.25%

Quarterly Estimates By Analyst

Zacks Premium Subscription Required Learn more

Annual Estimates By Analyst

Zacks Premium Subscription Required Learn more

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Value Line Reports

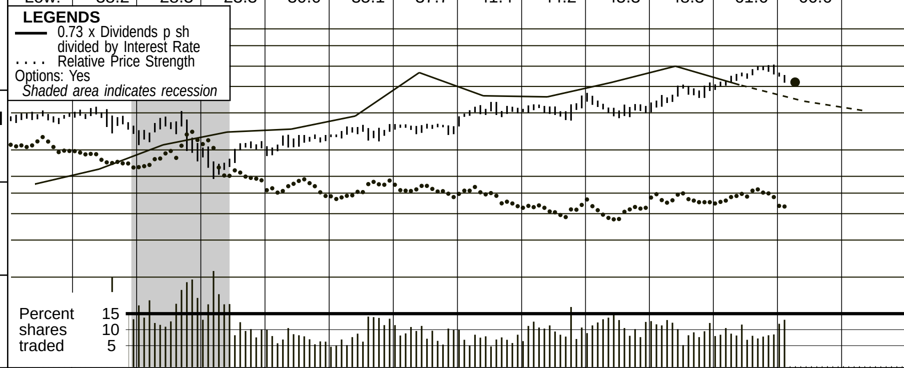
ALLETE NYSE-ALE

RECENT PRICE **67.19** | P/E RATIO **21.6** (Trailing: 21.5; Median: 16.0) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **3.4%** | **VALUE LINE**

TIMELINESS 3 Lowered 1/26/18
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 3/2/18
BETA .75 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High:	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	81.2
Low:	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6

	High:	Low:
74.4	74.4	66.6



Target Price Range
2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+10%)	6%
Low	55	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	8	0	0	1	0	0	0	8
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	140	118	117
to Sell	108	124	98
Hld's(000)	43781	44573	38769

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.5	10.1
3 yr.	38.0	24.2
5 yr.	73.9	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
- -	- -	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	*28.45*	*28.85*	Revenues per sh	*30.75*
- -	- -	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	*7.00*	*7.35*	"Cash Flow" per sh	*8.50*
- -	- -	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	*3.40*	*3.60*	Earnings per sh A	*4.25*
- -	- -	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	*2.24*	*2.34*	Div'd Decl'd per sh B ■ †	*2.70*
- -	- -	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	*6.25*	*6.80*	Cap'l Spending per sh	*6.25*
- -	- -	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	*42.10*	*43.80*	Book Value per sh C	*49.25*
- -	- -	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	*52.00*	*53.00*	Common Shs Outst'g D	*56.00*
- -	- -	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
- -	- -	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.14	*Value Line*		Relative P/E Ratio	*.85*
- -	- -	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	1419.3	*1480*	*1530*	Revenues ($mill)	*1725*
82.5	61.0	75.3	93.8	97.1	104.7	124.8	163.4	155.3	159.2	*175*	*190*	Net Profit ($mill)	*235*
34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	*NMF*	*Nil*	Income Tax Rate	*Nil*
5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	.8%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	*40.5%*	*38.5%*	Long-Term Debt Ratio	*38.0%*
58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	*59.5%*	*61.5%*	Common Equity Ratio	*62.0%*
1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	*3685*	*3785*	Total Capital ($mill)	*4450*
1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	*3960*	*4120*	Net Plant ($mill)	*4275*
6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.0%*	Return on Com Equity E	*8.5%*
3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
61%	93%	81%	66%	71%	72%	67%	60%	66%	68%	*66%*	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1503.3 mill. **Due in 5 Yrs** $450.5 mill.
LT Debt $1439.2 mill. **LT Interest** $61.9 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $14.2 mill.

Pension Assets-12/17 $628.2 mill. **Oblig** $793.2 mill.

Pfd Stock None

Common Stock 51,143,656 shs.
as of 2/1/18
MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-8.9	-2.3	+8.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.40	NA	NA
Capacity at Peak (Mw)	1942	NA	NA
Peak Load, Winter (Mw)	1631	1520	1599
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	381	318	339

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	2.5%	*1.5%*
"Cash Flow"	5.0%	7.5%	*3.5%*
Earnings	1.5%	5.5%	*4.5%*
Dividends	3.5%	3.0%	*4.5%*
Book Value	6.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	320.0	323.3	462.5	380.6	1486.4
2016	333.8	314.8	349.6	341.5	1339.7
2017	365.6	353.3	362.5	337.9	1419.3
2018	*370*	*360*	*390*	*360*	*1480*
2019	*380*	*375*	*400*	*375*	*1530*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	.85	.46	1.23	.83	3.38
2016	.93	.50	.81	.89	3.14
2017	.97	.72	.88	.56	3.13
2018	*1.00*	*.60*	*.95*	*.85*	*3.40*
2019	*1.05*	*.65*	*1.00*	*.90*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	2.02
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535	.535	2.14
2018	.56				

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 41%; wind, 12%; other, 6%; purchased, 41%. Fuel costs: 28% of revs. '17 deprec. rate: 3.2%. Has 2,000 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's main utility subsidiary received a disappointing rate decision. Minnesota Power had sought a rate increase of $55 million (8.6%), based on a 10.25% return on a 53.8% common-equity ratio. The state commission (through a verbal order) granted a hike of $13 million (2.0%), based on a 9.25% return on the same common-equity ratio. Minnesota Power expected to receive a written order shortly after our report went to press, and plans to decide what steps it will take once management reviews the order.

We think earnings will advance solidly in 2018. Minnesota Power should benefit from healthy industrial demand for power. The utility is also earning a return on the construction work in progress for a transmission line that is scheduled for completion in 2020. ALLETE's wind-energy subsidiary should benefit from increased production and the construction and sale of a 50-megawatt project to a utility in North Dakota. U.S. Water Services is seeing rising demand for its water-treatment services and a full year of revenues from an acquisition it made last September. Our 2018 share-earnings estimate is within ALLETE's targeted range of $3.20-$3.50. Note that the company's profits in the fourth quarter of 2017 benefited from the revaluation of deferred taxes due to the new federal tax law. This added $0.25 a share to the bottom line, which we excluded as a nonrecurring item.

We forecast solid profit growth next year. The factors that are likely to help earnings in 2018 should be present in 2019, as well. We look for a 6% increase in share net, which is within ALLETE's annual growth goal of 5%-7%.

The board of directors raised the dividend in the first quarter. The annual increase was $0.10 a share (4.7%), a greater hike than in recent years. The accelerated growth rate is in line with the company's expectation of faster profit growth. ALLETE is targeting a payout ratio of 60%-65%.

This stock's dividend yield is close to the average for electric utility equities. With the recent quotation above the midpoint of our 3- to 5-year Target Price Range, total return potential is unappealing.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '04, (25¢); '05, ($1.84); '15, (46¢); '17, 25¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '17: $11.95/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '17: 8.6%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	85

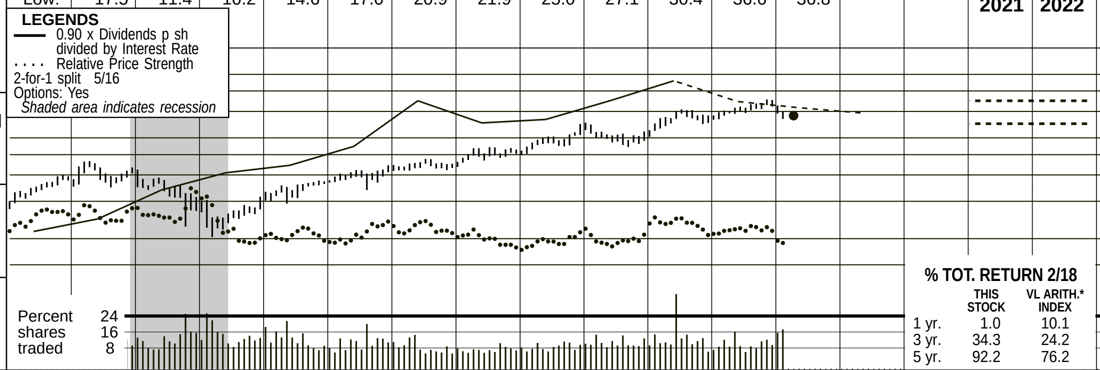
ALLIANT ENERGY NYSE-LNT

RECENT PRICE **38.17** | P/E RATIO **17.7** (Trailing: 19.2 / Median: 15.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS 2 Raised 3/9/18
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Lowered 3/2/18
BETA .70 (1.00 = Market)

High:	23.3	21.2	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	45.6	42.7
Low:	17.5	11.4	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8

LEGENDS
—— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-10%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	1	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	198	194	190
to Sell	188	187	165
Hld's(000)	179256	182717	166325

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.0	10.1
3 yr.	34.3	24.2
5 yr.	92.2	76.2

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	**15.30**	**15.55**	Revenues per sh	**17.75**
	2.28	2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.97	**4.25**	**4.45**	"Cash Flow" per sh	**5.00**
	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	**2.10**	**2.25**	Earnings per sh A	**2.60**
	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	**1.34**	**1.42**	Div'd Decl'd per sh B ■ †	**1.66**
	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	**6.75**	**7.10**	Cap'l Spending per sh	**5.30**
	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	**19.00**	**20.25**	Book Value per sh C	**22.85**
	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	**233.00**	**235.00**	Common Shs Outst'g D	**235.00**
	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**15.0**
	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.01			Relative P/E Ratio	**.85**
	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%			Avg Ann'l Div'd Yield	**4.3%**
	3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	**3560**	**3650**	Revenues ($mill)	**4175**
	280.0	208.6	303.9	304.4	337.8	382.1	385.5	380.7	373.8	455.9	**490**	**530**	Net Profit ($mill)	**610**
	33.4%	--	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	**12.0%**	**12.0%**	Income Tax Rate	**12.0%**
	--	--	--	--	--	--	--	6.5%	7.0%	7.0%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**7.0%**
	36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	49.0%	**50.0%**	**50.0%**	Long-Term Debt Ratio	**50.0%**
	58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	51.0%	**50.0%**	**50.0%**	Common Equity Ratio	**50.0%**
	4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	8192.8	**8300**	**8400**	Total Capital ($mill)	**8700**
	5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	9809.9	10797.9	**11125**	**11645**	Net Plant ($mill)	**12900**
	7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	5.6%	**6.0%**	**6.5%**	Return on Total Cap'l	**7.0%**
	9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	10.9%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.5%**
	9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	10.9%	**11.0%**	**11.0%**	Return on Com Equity E	**11.5%**
	3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	4.0%	**4.0%**	**4.0%**	Retained to Com Eq	**4.0%**
	62%	88%	64%	67%	64%	57%	59%	65%	72%	63%	**64%**	**63%**	All Div'ds to Net Prof	**64%**

CAPITAL STRUCTURE as of 12/31/17
Total Debt $5186.5 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $4010.6 mill. **LT Interest** $180.0 mill.
(LT interest earned: 4.0x)

Pension Assets-12/17 $950.7 mill. **Oblig.** $1303.1 mill.
Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 231,348,646 shs.

MARKET CAP: $8.8 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.1	+2.0	1.0
Avg. Indust. Use (MWH)	11735	11987	12102
Avg. Indust. Revs. per KWH (¢)	6.92	7.04	7.16
Capacity at Peak (Mw)	5385	5615	5375
Peak Load, Summer (Mw)	5385	5615	5375
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	+.4
Fixed Charge Cov. (%)	315	295	319

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	.5%	-1.5%	3.0%
"Cash Flow"	3.5%	6.5%	5.5%
Earnings	5.0%	6.5%	6.5%
Dividends	7.5%	6.5%	6.0%
Book Value	4.0%	4.5%	5.0%

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	897.4	717.2	898.9	740.1	3253.6
2016	843.8	754.2	925.0	797.0	3320.0
2017	853.9	765.3	906.9	856.1	3382.2
2018	**950**	**790**	**945**	**875**	**3560**
2019	**960**	**815**	**975**	**900**	**3650**

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.44	.30	.80	.15	1.69
2016	.43	.37	.57	.28	1.65
2017	.44	.41	.73	.41	1.99
2018	**.50**	**.40**	**.85**	**.35**	**2.10**
2019	**.53**	**.43**	**.90**	**.39**	**2.25**

QUARTERLY DIVIDENDS PAID B ■†

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.255	.255	.255	.255	1.02
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315	.315	.315	.315	1.26
2018	.335				

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 38%; IA, 61%; MN, 1%. Elect. rev.: residential, 36%; commercial, 24%; industrial, 30%; wholesale, 8%; other, 2%. Fuel sources, 2017: coal, 40%; gas, 17%; other, 43%. Fuel costs: 45% of revs. 2017 depreciation rate: 5.5%. Estimated plant age: 15 years. Has approximately 3,989 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy's largest utility subsidiary has reached a settlement of its rate case. Under the agreement, electric rates for Interstate Power and Light Company (IPL) would rise $130 million (7.8%) in 2018. That is down from the original $176 million (11.6%) request, but within our range of estimates. The Iowa Utilities Board also approved a return on common equity of 9.6% and said that temporary rates, which have been in effect since April 2017, would remain until the board reviews and approves tariff filings to be made by Alliant. The company said it would use the funds to upgrade power grids and improve facilities like the Marshalltown natural gas generating station.

Earnings should advance in 2018 and 2019. Each year, the utility is expected to benefit from electric and gas rate increases at IPL and Wisconsin Power and Light Company (WPL). Our 2018 profit estimate is near the midpoint of management's guidance range of $2.04-$2.18 a share, while our 2019 estimate calls for 7% year-on-year growth. It should be noted that tax reform is not forecasted to have a material impact on earnings. This is because much of the anticipated savings will be returned to customers through fewer/lower rate increases over time.

Wind energy remains an area of focus for Alliant. In December, the utility agreed to purchase English Farms Wind Farm for an undisclosed sum. The 170-megawatt, Iowa-based project is expected to power approximately 75,000 homes upon completion. Alliant is aiming to generate at least one-third of its Iowa energy mix from wind starting in 2020.

The board raised the dividend in the first quarter of 2018. This is the usual timing of the annual increase. The directors boosted the yearly disbursement by $0.08 a share (6.3%), the same increase as in each of the past four years. Alliant is targeting a payout ratio of 60%-70%.

This good-quality stock is well ranked for year-ahead relative price performance. The dividend yield is slightly below the median for a utility. Appreciation potential, while improved since our December report, is still well below the *Value Line* median. Accordingly, we advise long-term investors to wait on the sidelines.

Daniel Henigson *March 16, 2018*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '08, 4¢; '09, (44¢); '10, (8¢); '11, (1¢); '12, (8¢). Next earnings report due early May. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. In '17: $69.7 mill., $0.30/sh. (D) In millions, adjusted for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '17: 10.5%; in WI in '17 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	90

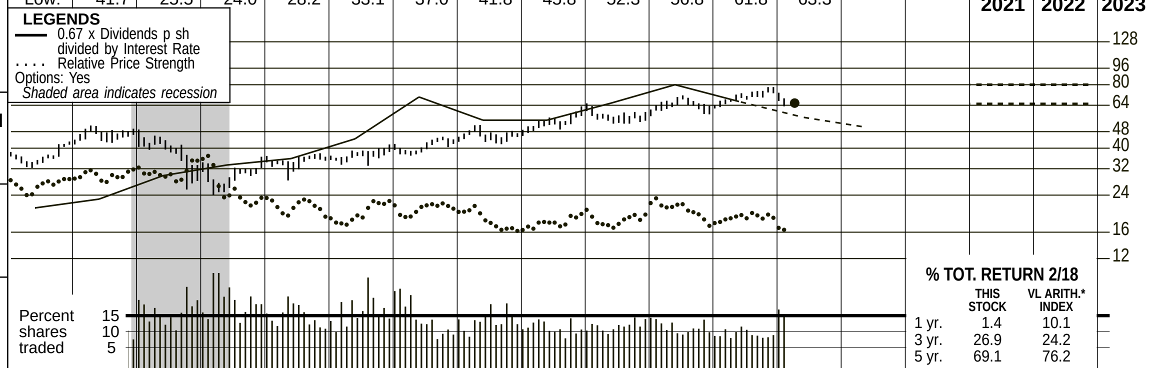
AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE 65.50 | P/E RATIO 16.5 (Trailing: 18.1; Median: 14.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 1/19/18
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Lowered 3/2/18
BETA .65 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High:	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	78.1	73.4
Low:	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8	61.8	63.3

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+20%)	9%
Low	65	(Nil)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	9	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	376	388	371
to Sell	369	351	342
Hld's(000)	384520	382879	352776

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.4	10.1
3 yr.	26.9	24.2
5 yr.	69.1	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	*30.60*	*31.30*	Revenues per sh	*33.00*
6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	*8.30*	*8.60*	"Cash Flow" per sh	*9.50*
2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	*3.90*	*4.10*	Earnings per sh A	*5.00*
2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	*2.51*	*2.63*	Div'd Decl'd per sh B ■	*3.05*
5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	*12.50*	*12.95*	Cap'l Spending per sh	*11.25*
20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	*38.70*	*40.25*	Book Value per sh C	*46.75*
338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	*493.50*	*495.00*	Common Shs Outst'g D	*516.00*
12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.96	*Value Line*		Relative P/E Ratio	*.80*
6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
14440	13489	14427	15116	14945	15357	17020	16453	16380	15425	*15100*	*15500*	Revenues ($mill)	*17000*
1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	*1870*	*1960*	Net Profit ($mill)	*2490*
31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*6.0%*
59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	*52.5%*	*54.5%*	Long-Term Debt Ratio	*50.5%*
40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	*47.5%*	*45.5%*	Common Equity Ratio	*49.5%*
26290	28958	29184	29747	30823	32913	33001	35633	34775	37707	*40325*	*43775*	Total Capital ($mill)	*48800*
32987	34344	35674	36971	38763	40997	44117	46133	45639	50262	*54250*	*58450*	Net Plant ($mill)	*68700*
6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
55%	56%	66%	60%	63%	62%	61%	60%	54%	67%	*66%*	*66%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $22812 mill. **Due in 5 Yrs** $9694 mill.
LT Debt $19420 mill. **LT Interest** $874 mill.
Incl. $1410.5 mill. securitized bonds. Incl. $294 mill. capitalized leases.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $245.9 mill.
Pension Assets-12/17 $5174.1 mill.
Oblig $5215.8 mill.
Pfd Stock None

Common Stock 492,005,598 shs.

MARKET CAP: $32 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.2	+.3	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	NA	NA
Fixed Charge Cov. (%)	356	374	354

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	- -	1.5%	*Nil*
"Cash Flow"	2.5%	4.0%	*2.5%*
Earnings	3.0%	5.5%	*4.5%*
Dividends	4.0%	4.5%	*5.0%*
Book Value	4.0%	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	4580	3827	4431	3615	16453
2016	4045	3893	4652	3790	16380
2017	3933	3577	4105	3810	15425
2018	*3850*	*3450*	*4100*	*3700*	*15100*
2019	*4000*	*3650*	*4200*	*3650*	*15500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.27	.88	1.04	.41	3.59
2016	1.02	1.03	1.43	.76	4.23
2017	.94	.76	1.11	.81	3.62
2018	*1.10*	*.80*	*1.25*	*.75*	*3.90*
2019	*1.15*	*.85*	*1.30*	*.80*	*4.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	2.15
2016	.56	.56	.56	.59	2.27
2017	.59	.59	.59	.62	2.39
2018	.62				

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 34% of revenues. '17 reported depreciation rates (utility): 1.6%-9.2%. Has 17,700 employees. Chairman, President & CEO: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power's earnings will likely advance solidly in 2018 and 2019. The company's utilities are benefiting from rate relief. Public Service of Oklahoma received an $84 million rate increase (before passing through to customers the reduction in federal taxes), based on a 9.3% return on equity. Also this quarter, SWEPCo was granted a hike of $50 million, based on a 9.6% ROE. Indiana & Michigan has rate cases pending in each state. In Indiana, the utility reached a settlement (subject to approval by the state commission) for an increase of $97 million, based on a 9.95% ROE. New tariffs would take effect in mid-2018. In Michigan, I&M requested a $52 million hike, based on a 10.6% ROE. An order is expected in April. Heavy investment in electric transmission (some $3 billion annually) is also expanding the company's earning power. Our 2018 and 2019 share-earnings estimates are within AEP's targeted ranges of $3.75-$3.95 and $4.00-$4.20, respectively.

The company wants to build a large wind project to serve four states. The 2,000-megawatt facility would cost $4.5 billion and would be completed by the fourth quarter of 2020. This needs the approval of the state commissions in Oklahoma, Arkansas, Texas, and Louisiana. (Opposition to the project has emerged in Oklahoma.) Rulings on the proposals are expected by the end of April.

AEP no longer has exposure to the vagaries of the power markets. The company has sold or written off its nonregulated generating facilities. (This caused a large nonrecurring charge in 2016.) It is still seeking a buyer for its remaining generating assets.

Finances are solid. The fixed-charge coverage, common-equity ratio, and earned ROE are healthy. AEP's exit from merchant (uncontracted) power has lowered its business risk, too. The company's Financial Strength rating is A+.

The stock has a dividend yield that is somewhat above the utility average. This might well appeal to conservative investors, given the stock's Safety rank of 1 (Highest). Total return potential to 2021-2023 does not stand out among electric companies, however.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; disc. ops.: '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). '15-'16 EPS don't sum due to rounding. Next egs. report due late April. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '17: $12.59/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '17: 10.0%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	85

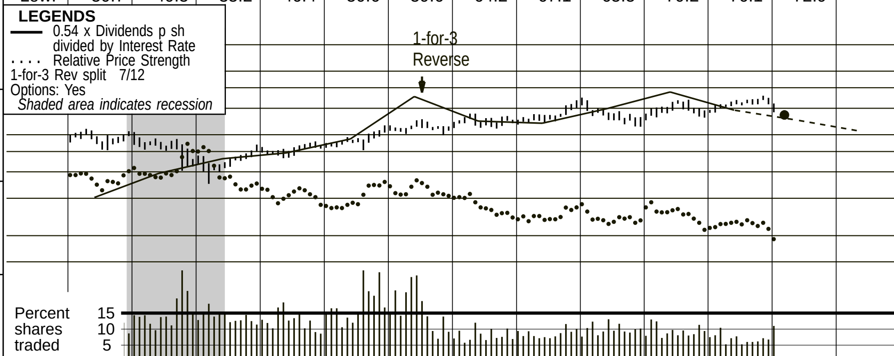
DUKE ENERGY NYSE-DUK

RECENT PRICE	74.49	P/E RATIO	15.9 (Trailing: 19.1 Median: 17.0)	RELATIVE P/E RATIO	0.83	DIV'D YLD	4.9%	VALUE LINE

TIMELINESS 4 Lowered 6/23/17
SAFETY 2 New 6/1/07
TECHNICAL 1 Raised 12/22/17
BETA .60 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.8	91.8	84.4
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.9

Target Price Range
2021 | 2022 | 2023



160 120 100 80 60 50 40 30 20 15

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+50%)	14%
Low	85	(+15%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	2	0	0	0	0	0	0	0
Options	0	6	0	0	0	0	0	0	0
to Sell	0	2	0	0	1	0	0	1	0

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	552	528	531
to Sell	500	509	494
Hld's(000)	437355	435858	442941

% TOT. RETURN 1/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.2	17.3
3 yr.	2.4	38.0
5 yr.	41.5	85.6

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
- -	- -	- -	- -	- -	- -	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	**33.50**	**33.85**	**34.80**	Revenues per sh	**37.75**
- -	- -	- -	- -	- -	- -	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	**10.15**	**10.95**	**11.40**	"Cash Flow" per sh	**13.00**
- -	- -	- -	- -	- -	- -	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	**4.30**	**4.80**	**5.00**	Earnings per sh A	**5.50**
- -	- -	- -	- -	- -	- -	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	**3.64**	**3.80**	Div'd Decl'd per sh B ■	**4.40**
- -	- -	- -	- -	- -	- -	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	**13.45**	**15.35**	**15.25**	Cap'l Spending per sh	**12.75**
- -	- -	- -	- -	- -	- -	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	**59.35**	**60.45**	**61.60**	Book Value per sh C	**65.00**
- -	- -	- -	- -	- -	- -	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	**701.00**	**702.00**	**703.00**	Common Shs Outst'g D	**706.00**
- -	- -	- -	- -	- -	- -	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	**19.6**	*Bold figures are*		Avg Ann'l P/E Ratio	**18.0**
- -	- -	- -	- -	- -	- -	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	**.95**	*Value Line*		Relative P/E Ratio	**1.00**
- -	- -	- -	- -	- -	- -	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	*estimates*		Avg Ann'l Div'd Yield	**4.5%**

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
13207	12731	14272	14529	19624	24598	23925	23459	22743	**23500**	**23750**	**24450**	Revenues ($mill)	**26650**
1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	**3005**	**3385**	**3515**	Net Profit ($mill)	**3970**
32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	**31.5%**	**20.0%**	**20.0%**	Income Tax Rate	**20.0%**
16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	**13.0%**	**12.0%**	**12.0%**	AFUDC % to Net Profit	**11.0%**
38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	**54.0%**	**54.5%**	**55.5%**	Long-Term Debt Ratio	**57.0%**
61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	**46.0%**	**45.5%**	**44.5%**	Common Equity Ratio	**43.0%**
34238	37863	40457	41451	77307	79482	78088	77222	86609	**90200**	**93525**	**96900**	Total Capital ($mill)	**107000**
34036	37950	40344	42661	68558	69490	70046	75709	82520	**87850**	**94325**	**100525**	Net Plant ($mill)	**112900**
4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	**4.5%**	**4.5%**	**4.5%**	Return on Total Cap'l	**5.0%**
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	**7.0%**	**8.0%**	**8.0%**	Return on Shr. Equity	**8.5%**
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	**7.0%**	**8.0%**	**8.0%**	Return on Com Equity E	**8.5%**
.6%	1.1%	2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	**1.5%**	**2.0%**	**2.0%**	Retained to Com Eq	**2.0%**
89%	84%	73%	72%	82%	78%	76%	79%	91%	**81%**	**75%**	**76%**	All Div'ds to Net Prof	**78%**

CAPITAL STRUCTURE as of 9/30/17
Total Debt $53313 mill. **Due in 5 Yrs** $18876 mill.
LT Debt $48929 mill. **LT Interest** $1795 mill.
Incl. $1100 mill. capitalized leases.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $218 mill.
Pension Assets-12/16 $8531 mill.
Oblig $8006 mill.
Pfd Stock None

Common Stock 699,975,614 shs.

MARKET CAP: $52 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.2	+.6	-.3
Avg. Indust. Use (MWH)	2876	2883	3486
Avg. Indust. Revs. per KWH (¢)	6.15	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.0	+1.2	+1.4
Fixed Charge Cov. (%)	315	317	264

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	3.0%	1.5%	1.5%
"Cash Flow"	1.5%	2.5%	5.0%
Earnings	3.5%	.5%	4.5%
Dividends	- -	2.5%	4.5%
Book Value	-.5%	3.0%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	6065	5589	6483	5322	23459
2016	5377	5213	6576	5577	22743
2017	5729	5555	6482	**5734**	**23500**
2018	**5750**	**5600**	**6600**	**5800**	**23750**
2019	**5900**	**5700**	**6950**	**5900**	**24450**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.87	1.44	.70	4.10
2016	.83	.90	1.44	.53	3.71
2017	1.02	.98	1.36	**.94**	**4.30**
2018	**1.05**	**1.05**	**1.65**	**1.05**	**4.80**
2019	**1.10**	**1.10**	**1.70**	**1.10**	**5.00**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.78	.78	.795	.795	3.15
2015	.795	.795	.825	.825	3.24
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018					

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.4 mill. elec. customers in NC, FL, IN, SC, Oh, & KY, and 1.5 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 43%; commercial, 29%; industrial, 14%; other, 14%. Generating sources: coal, 27%; nuclear, 27%; gas, 23%; other, 1%; purchased, 22%. Fuel costs: 30% of revs. '16 reported deprec. rate: 2.8%. Has 28,800 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

One of Duke Energy's utilities has reached a partial settlement of its rate case. Duke Energy Progress filed for an increase of $477 million (14.9%), based on a 10.75% return on a 53% common-equity ratio. The settlement with the staff of the North Carolina Utilities Commission (NCUC) would provide for a hike (before the pass-through of reduced federal income taxes) of $127 million (4.0%), based on a return of 9.9% on a common-equity ratio of 52%. The treatment of deferred costs associated with storms and coal ash basin remediation has not been resolved, so far.

Other rate cases are pending. Duke Energy Carolinas asked the NCUC for an increase of $647 million (13.6%), based on a 10.75% return on a 53% common-equity ratio. New tariffs should take effect in the second quarter. Duke asked the Kentucky commission for a boost of $48.6 million (15%), based on a 10.3% return on a 49% common-equity ratio. New rates are likely to take effect in April.

We estimate a sharp earnings increase in 2018, followed by a more moderate rise in 2019. Last year, the third-period tally was weakened by unfavorable weather conditions, an $0.08-a-share write-off of a nonregulated wind-farm, and a $0.12-a-share charge for the cancelation of a nuclear project that was under consideration in Florida. Rate relief should be a positive factor for the bottom line each year. All told, we estimate share earnings of $4.80 this year and $5.00 in 2019.

Some significant capital projects are under way. Duke is building gas-fired plants in South Carolina and Florida and modernizing the electric system in Indiana and the western Carolinas. This will expand the company's rate base, and thus, its earning power. Duke also intends to expand its gas pipeline infrastructure. The company's goal for average annual profit growth is 4%-6%.

This stock is ranked unfavorably for Timeliness, but offers a dividend yield that is well above the utility average. The yield is about a percentage point above the norm for this industry. Total return potential over the 3- to 5-year period is attractive.

Paul E. Debbas, CFA *February 16, 2018*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; gains (losses) on disc. ops.: '12, 6¢; '13, 2¢; '14, (80¢); '15, 5¢; '16, (60¢). '16 EPS don't sum due to rounding. Next egs. report due early May. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '16: $46.17/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC: 10.2%; in '17 in SC: 10.1%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earn. on avg. com. eq., '16: 6.3%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	85

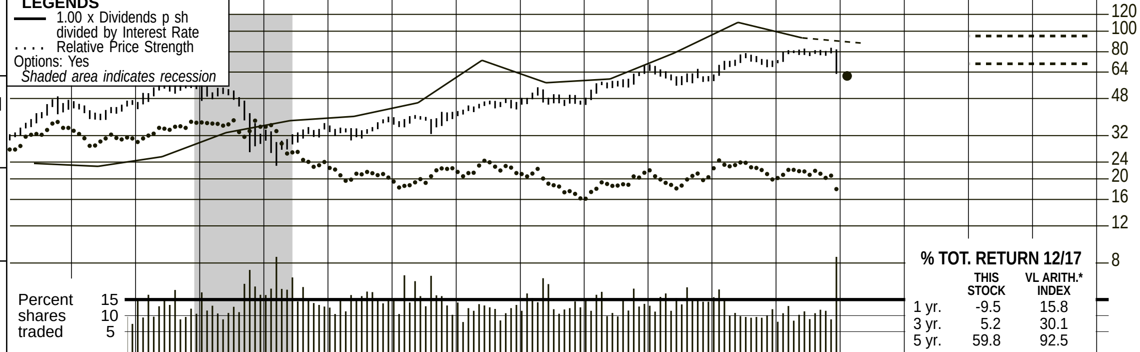
EDISON INTERNAT'L NYSE-EIX

RECENT PRICE **61.33** | P/E RATIO **14.0** (Trailing: 14.1 / Median: 12.0) | RELATIVE P/E RATIO **0.68** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS **2** Raised 11/17/17
SAFETY **2** Raised 5/3/13
TECHNICAL **2** Lowered 1/19/18
BETA .65 (1.00 = Market)

High:	47.2	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6	78.7	83.4
Low:	37.9	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	62.7

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+55%)	15%
Low	70	(+15%)	7%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	2	2	3	2	0	1	0	0	1
to Sell	1	1	1	2	0	1	0	0	1

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	252	299	274
to Sell	273	236	258
Hld's(000)	292772	290101	288374

Percent shares traded 15 10 5

% TOT. RETURN 12/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-9.5	15.8
3 yr.	5.2	30.1
5 yr.	59.8	92.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	*37.00*	*38.20*	Revenues per sh	*44.25*
4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	*11.20*	*11.55*	"Cash Flow" per sh	*13.75*
1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	*4.35*	*4.40*	Earnings per sh A	*5.25*
--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	*2.45*	Div'd Decl'd per sh B ■	*2.90*
2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	*13.10*	*15.40*	Cap'l Spending per sh	*16.00*
10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	*38.40*	*39.80*	Book Value per sh C	*44.75*
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	*18.1*		Avg Ann'l P/E Ratio	*15.5*
.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	*.90*		Relative P/E Ratio	*.95*
--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $13129 mill. **Due in 5 Yrs** $3408 mill.
LT Debt $11638 mill. **LT Interest** $569 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $393 mill.
Pens. Assets-12/16 $3388 mill. **Oblig** $4284 mill.
Pfd Stock $2654 mill. **Pfd Div'd** $123 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 10/27/17**
MARKET CAP: $20 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
13113	14112	12374	12409	12760	11862	12581	13413	11524	11869	*12050*	*12450*	Revenues ($mill)	*14400*
1151.0	1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1422.0	*1565*	*1575*	Net Profit ($mill)	*1870*
27.3%	30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	11.1%	*Nil*	*180.0%*	Income Tax Rate	*10.0%*
8.2%	8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	6.8%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
49.1%	51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	41.8%	*43.5%*	*45.5%*	Long-Term Debt Ratio	*46.0%*
46.0%	44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	49.2%	*48.0%*	*46.5%*	Common Equity Ratio	*47.0%*
18375	21374	21185	23861	24773	20422	21516	23216	24352	24362	*25975*	*27925*	Total Capital ($mill)	*31100*
17403	18969	21966	24778	32116	30273	30455	32981	35085	37000	*39075*	*41775*	Net Plant ($mill)	*49400*
8.3%	7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.9%	*7.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
12.3%	12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
13.0%	12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	10.8%	*11.5%*	*11.0%*	Return on Com Equity E	*12.0%*
9.2%	8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.6%	*5.5%*	*5.0%*	Retained to Com Eq	*5.5%*
33%	35%	41%	40%	43%	32%	40%	37%	44%	53%	*54%*	*58%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.1	-1.4	-2.6
Avg. Indust. Use (MWH)	788	703	664
Avg. Indust. Revs. per KWH (¢)	8.86	9.07	6.51
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23055	23079	23091
Annual Load Factor (%)	52.3	52.2	50.7
% Change Customers (yr-end)	+.6	+.6	+.5
Fixed Charge Cov. (%)	306	247	246

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	5.5%	4.0%	*5.0%*
Earnings	5.5%	5.0%	*4.0%*
Dividends	6.0%	6.5%	*9.0%*
Book Value	5.5%	2.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2926	3016	4356	3115	13413
2015	2512	2908	3763	2341	11524
2016	2440	2777	3767	2885	11869
2017	2463	2965	3672	*2950*	*12050*
2018	*2500*	*3000*	*3950*	*3000*	*12450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.61	1.07	1.51	1.15	4.33
2015	.91	1.15	1.15	.94	4.15
2016	.85	.86	1.27	.96	3.94
2017	1.11	.85	1.44	*.95*	*4.35*
2018	*1.10*	*.90*	*1.40*	*1.00*	*4.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.355	.355	.355	.355	1.42
2015	.4175	.4175	.4175	.4175	1.67
2016	.48	.48	.48	.48	1.92
2017	.5425	.5425	.5425	.5425	2.17
2018	.605				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.1 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 6%; nuclear, 6%; hydro, 5%; purchased, 83%. Fuel costs: 38% of revs. '16 reported depr. rate: 3.8%. Has 12,400 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International's stock price has plummeted in recent weeks due to investors' concerns about the possible wildfire liability of its utility subsidiary. The share price is down more than 25% from its 52-week high. The service area of Southern California Edison experienced wildfires in the fall of 2017. The cause of the fires has not yet been determined. However, under California's inverse condemnation law, a utility can be held liable if its power lines contributed to the wildfires, even if the utility followed acceptable inspection and safety rules. SCE has $1 billion in liability insurance. Moreover, there is no guarantee that the utility will be able to pass through to customers any restoration and other costs stemming from the wildfires. Despite the uncertainty surrounding this matter . . .

The board of directors raised the dividend significantly at the December meeting. The annual increase was $0.25 a share (11.5%). By contrast, about two weeks after the board's action, the directors of PG&E Corporation (the parent of Pacific Gas and Electric in northern California) suspended the dividends of its common and preferred stocks due to similar wildfire worries. PG&E's move exacerbated the decline in Edison International's stock price. Even so, we think the company's dividend is not facing the risk of a cut.

The utility is still awaiting an order on its general rate case. SCE is seeking rate hikes of $10 million this year, $477 million in 2019, and $554 million in 2020. SCE forecasts capital spending of $14.8 billion for the three-year request, including $1.8 billion for modernization of the electric grid. This portion of the proposal has proved controversial. The CPUC's order will be retroactive to the start of 2018.

This timely stock has a dividend yield that is a cut above the utility average. Investors with a 3- to 5-year horizon should receive a respectable total return. However, they must be willing to accept the uncertainty surrounding the wildfires. Another uncertainty concerns the possibility of additional refunds and/or customer credits stemming from the closing of the San Onofre nuclear plant. SCE's customers have already received refunds and credits totaling nearly $1.6 billion.

Paul E. Debbas, CFA *January 26, 2018*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '16, 3¢. '14 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '16: $22.88/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '16: 11.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	60

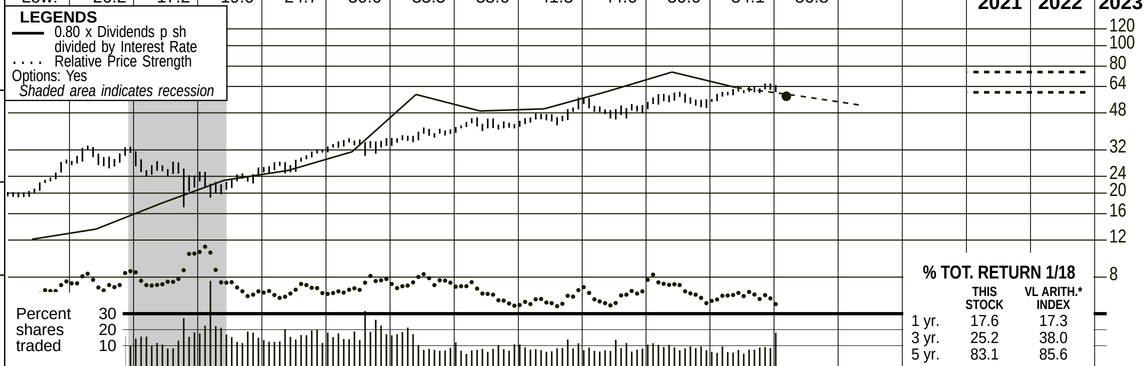
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE **57.54** | P/E RATIO **17.5** (Trailing: 18.7; Median: 17.0) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS	**3** Lowered 1/19/18
SAFETY	**1** Raised 5/22/15
TECHNICAL	**2** Raised 2/16/18
BETA .65 (1.00 = Market)	

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High:	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8	60.4	66.1	65.0
Low:	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6	50.0	54.1	56.8

LEGENDS
—— 0.80 x Dividends p sh divided by Interest Rate
. . . . Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+30%)	*10%*
Low	60	(+5%)	*5%*

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	1	0	0	0	0	0	0
to Sell	0	1	1	0	0	0	0	0	0

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	268	270	274
to Sell	246	253	232
Hld's(000)	250335	253282	253377

% TOT. RETURN 1/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.6	17.3
3 yr.	25.2	38.0
5 yr.	83.1	85.6

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	*24.15*	*24.60*	*25.25*	Revenues per sh	*27.50*
6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	*5.75*	*6.15*	*6.55*	"Cash Flow" per sh	*8.00*
1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	*3.10*	*3.30*	*3.50*	Earnings per sh A	*4.25*
.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	*2.02*	*2.14*	Div'd Decl'd per sh B ■	*2.50*
3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	*8.55*	*9.15*	*8.20*	Cap'l Spending per sh	*5.75*
17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	*35.00*	*36.30*	*37.70*	Book Value per sh C	*42.50*
127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	*316.89*	*316.89*	*316.89*	Common Shs Outst'g D	*316.89*
16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	*19.5*	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	*.95*	*Value Line*		Relative P/E Ratio	*.90*
3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $11444 mill. **Due in 5 Yrs** $3718.4 mill.
LT Debt $10468 mill. **LT Interest** $418.7 mill.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $14.1 mill.
Pension Assets-12/16 $4076.0 mill. **Oblig** $5242.3 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption, call. at $50.50-$54.00; 430,000 shs 4.25%-4.78% not subject to mandatory redemption, call. at $102.80-$103.63.
Common Stock 316,885,808 shs. **as of 10/31/17**
MARKET CAP: $18 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	7954.8	7639.1	*7650*	*7800*	*8000*	Revenues ($mill)	*8700*
296.2	335.6	377.8	400.3	533.0	793.7	827.1	886.0	949.8	*995*	*1060*	*1120*	Net Profit ($mill)	*1370*
29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	37.9%	36.9%	*37.0%*	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	2.9%	3.9%	*5.0%*	*4.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	45.6%	44.8%	*49.5%*	*50.0%*	*50.5%*	Long-Term Debt Ratio	*51.0%*
38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	53.6%	54.4%	*49.5%*	*49.0%*	*49.0%*	Common Equity Ratio	*48.5%*
7926.2	8629.5	8741.8	8856.0	16675	17544	18738	19313	19697	*22375*	*23400*	*24425*	Total Capital ($mill)	*27800*
8207.9	8840.0	9567.7	10403	16605	17576	18647	19892	21351	*23375*	*25525*	*27300*	Net Plant ($mill)	*29700*
5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	5.5%	5.8%	*5.5%*	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	8.4%	8.7%	*9.0%*	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	8.8%	*9.0%*	*9.0%*	*9.5%*	Return on Com Equity E	*10.0%*
5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	3.4%	3.5%	*3.5%*	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
45%	50%	49%	50%	72%	59%	58%	61%	60%	*61%*	*61%*	*61%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.6	+.3	-1.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.14	5.86	6.04
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	426	447	436

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	-6.0%	-2.5%	*1.5%*
"Cash Flow"	.5%	-.5%	*7.0%*
Earnings	12.0%	6.0%	*6.5%*
Dividends	9.5%	10.5%	*6.0%*
Book Value	6.0%	8.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2513	1817	1933	1691	7954.8
2016	2056	1767	2040	1776	7639.1
2017	2105	1763	1989	*1793*	*7650*
2018	*2150*	*1800*	*2000*	*1850*	*7800*
2019	*2200*	*1850*	*2050*	*1900*	*8000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.80	.65	.74	.57	2.76
2016	.77	.64	.83	.72	2.96
2017	.82	.72	.82	*.74*	*3.10*
2018	*.90*	*.75*	*.90*	*.75*	*3.30*
2019	*.95*	*.80*	*.95*	*.80*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.3925	.3925	.3925	.3925	1.57
2015	.4175	.4175	.4175	.4175	1.67
2016	.445	.445	.445	.445	1.78
2017	.475	.475	.475	.475	1.90
2018	.505				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 mill. electric, 504,000 gas, 230,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17. Electric rev. breakdown: residential, 52%; commercial, 36%; industrial, 5%; other, 7%. Fuel costs: 33% of revs. '16 reported deprec. rate: 3.0%. Has 8,300 empls. Chairman, Pres. & CEO: James J. Judge. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy completed the acquisition of Aquarion Water in early December. The company paid $880 million in cash for the water utility, which serves nearly 230,000 customers in Connecticut (mostly), Massachusetts, and New Hampshire. Eversource also assumed $795 million of debt and borrowed $900 million to finance the purchase. The earnings from the addition of Aquarion Water should offset the lost income from the generating assets that Eversource's utility in New Hampshire has sold and is selling.

We estimate profits will advance 6% this year and next. This is within the company's goal of 5%-7% yearly growth. Eversource's utility in Massachusetts received rate relief at the start of February. It was granted (before the pass-through of federal tax cuts to customers) $37 million, based on a 10% return on equity. The utility will receive additional annual increases to compensate for the effects of inflation. Connecticut Light & Power reached a settlement that, if approved by the state regulators, will provide a tariff hike of $97 million on May 1st, $33 million a year later, and $25 million a year after that, based on a 9.25% ROE. Spending on electric transmission is also boosting the company's earning power. (There is some uncertainty about what the federally allowed ROE will be, but even in the worst case it will stay above the allowed ROEs for Eversource's distribution business.) On the gas side, the company is benefiting from the conversion of oil heating customers to gas.

A proposed transmission project has had a setback. Eversource wants to build a line to connect New England and Quebec. However, the New Hampshire Site Evaluation Committee denied the project's siting application. Eversource will seek reconsideration of this decision. It will have to write off some $200 million of development costs if the project is canceled.

The board of directors raised the dividend. The quarterly payout was increased by $0.03 a share (6.3%). Eversource's goal is 5%-7% annual dividend growth, the same as for earnings.

This high-quality stock has a dividend yield and 3- to 5-year total return potential that are about average for a utility.

Paul E. Debbas, CFA *February 16, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. Next earnings report due late Feb. **(B)** Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. def'd charges. In '16: $22.59 sh. **(D)** In mill. **(E)** Rate allowed on com. eq. in MA: (elec) '18, 10.0%; (gas) '16, 9.8%; in CT: (elec.) '15, 9.02%; (gas) '15, 9.5%; in NH: '10, 9.67%; earned on avg. com. eq., '16: 9.0%. Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	85

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE **31.20** | P/E RATIO **15.2** (Trailing: 16.3 / Median: 15.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **4.6%** | VALUE LINE

TIMELINESS 3 Lowered 1/12/18
SAFETY 2 Lowered 12/18/15
TECHNICAL 4 Raised 3/16/18
BETA .95 (1.00 = Market)

High:	20.7	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4	33.1
Low:	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6

2021-23 PROJECTIONS

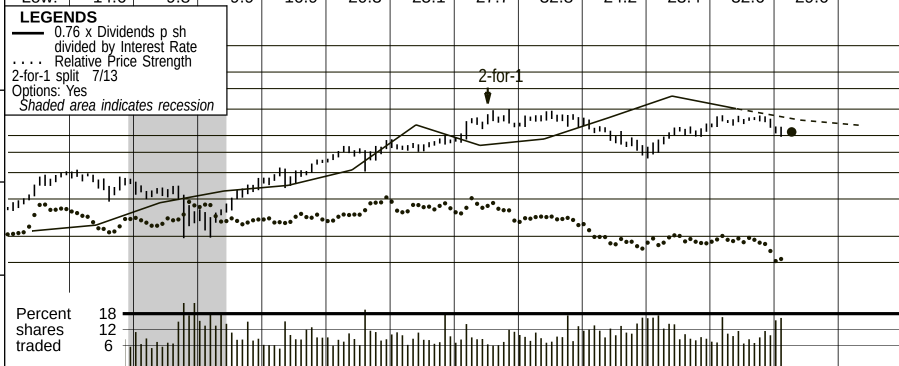
	Price	Gain	Ann'l Total Return
High	50	(+60%)	16%
Low	35	(+10%)	8%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	2	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	159	151	155
to Sell	202	155	138
Hld's(000)	145860	145781	124353



Target Price Range 2021 | 2022 | 2023
80 60 50 40 30 25 20 15 10 7.5

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.7	10.1
3 yr.	7.7	24.2
5 yr.	26.5	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	**11.75**	**12.50**	Revenues per sh	**14.75**
1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	**3.60**	**4.00**	"Cash Flow" per sh	**4.75**
.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	**2.05**	**2.15**	Earnings per sh A	**2.50**
.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	**1.40**	**1.54**	Div'd Decl'd per sh B ■	**1.85**
1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	**3.15**	**3.15**	Cap'l Spending per sh	**2.75**
6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	**19.95**	**20.55**	Book Value per sh C	**22.50**
157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	**199.70**	**199.70**	Common Shs Outst'g D	**199.70**
14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.91	*Value Line*		Relative P/E Ratio	**.95**
6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	*estimates*		Avg Ann'l Div'd Yield	**4.3%**

CAPITAL STRUCTURE as of 12/31/17
Total Debt $3168.1 mill. **Due in 5 Yrs** $668.9 mill.
LT Debt $2749.6 mill. **LT Interest** $140.4 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $4.8 mill.

Pension Assets-12/17 $635.3 mill. **Oblig** $687.5 mill.

Pfd Stock None

Common Stock 199,706,104 shs. as of 1/31/18
MARKET CAP: $6.2 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	**2350**	**2500**	Revenues ($mill)	**2950**
231.4	258.3	295.3	342.9	355.0	387.6	395.8	337.6	338.2	384.3	**410**	**430**	Net Profit ($mill)	**500**
30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	**14.0%**	**14.0%**	Income Tax Rate	**14.0%**
1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	**8.0%**	**7.0%**	AFUDC % to Net Profit	**3.0%**
53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	**43.0%**	**44.0%**	Long-Term Debt Ratio	**45.5%**
46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	**57.0%**	**56.0%**	Common Equity Ratio	**54.5%**
4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	**6980**	**7350**	Total Capital ($mill)	**8225**
5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	**8660**	**8910**	Net Plant ($mill)	**9450**
7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.5%**
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	**10.0%**	**10.5%**	Return on Shr. Equity	**11.0%**
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	**10.0%**	**10.5%**	Return on Com Equity E	**11.0%**
5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	**3.0%**	**3.0%**	Retained to Com Eq	**3.0%**
55%	53%	48%	43%	44%	43%	47%	61%	67%	64%	**68%**	**72%**	All Div'ds to Net Prof	**74%**

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.9	-1.1	-2.2
Avg. Indust. Use (MWH)	754	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.05	5.17	5.30
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6537	6538	6456
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.1	+1.0
Fixed Charge Cov. (%)	314	336	315

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-8.0%	-10.0%	4.5%
"Cash Flow"	4.0%	-.5%	4.5%
Earnings	4.5%	1.0%	2.5%
Dividends	5.5%	8.5%	8.0%
Book Value	7.5%	6.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	480.1	549.9	719.8	447.1	2196.9
2016	433.1	551.4	743.9	530.8	2259.2
2017	456.0	586.4	716.8	501.9	2261.1
2018	*475*	*600*	*750*	*525*	*2350*
2019	*500*	*650*	*800*	*550*	*2500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.22	.44	.88	.15	1.69
2016	.13	.35	.92	.29	1.69
2017	.18	.52	.92	.30	1.92
2018	*.20*	*.50*	*1.05*	*.30*	*2.05*
2019	*.20*	*.55*	*1.10*	*.30*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.225	.225	.225	.25	.93
2015	.25	.25	.25	.275	1.03
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025	.3025	.3325	1.24
2018	.3325				

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 842,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.7% of Enable Midstream Partners. Electric revenue breakdown: residential, 40%; commercial, 26%; industrial, 9%; oilfield, 7%; other, 18%. Generating sources: coal, 34%; gas, 25%; wind, 4%; purchased, 37%. Fuel costs: 40% of revenues. '17 reported depreciation rate (utility): 2.5%. Has 2,400 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary has filed a general rate case in Oklahoma. Oklahoma Gas and Electric is asking the Oklahoma Corporation Commission (OCC) for an increase of $1.9 million, based on a return of 9.9% on a common-equity ratio of 53%. (The request would have been over $70 million were it not for the pass-through to customers of reduced federal taxes.) The utility is seeking to place in the rate base a $390 million project to modernize the 462-megawatt Mustang gas-fired plant; restore the depreciation rates to their level before the OCC cut these last year; and raise its allowed ROE from the current 9.5%. New tariffs are expected to take effect at the start of October. Note that in Arkansas, OG&E will recover its investment in Mustang through the state's formula rate plan.

The new federal tax law is benefiting earnings. The revaluation of deferred taxes produced a nonrecurring gain of $1.18 a share in the fourth quarter of 2017. This year, the lower tax rate applied to OGE Energy's income from its interest in Enable Midstream Partners will add $0.08 to share net.

Rate relief should benefit the company's profits this year and next. Our 2018 estimate of $2.05 a share is at the upper end of OGE Energy's targeted range of $1.90-$2.05. Also, we expect higher equity income from the stake in Enable as the master limited partnership's prospects improve.

Two environmental compliance projects are on track for completion by yearend. OG&E is adding scrubbers to two units at the Sooner coal-fired plant at a cost of $542 million. Another coal-fired unit is being converted to a gas-fired facility at cost of $76 million. The utility will file a rate application in Oklahoma in late 2018 in order to place these projects in the rate base.

The dividend yield of this stock is above the utility average. What's more, OGE Energy expects to hike the disbursement by 10% annually through next year. Even if the board doesn't maintain such a high growth rate beyond 2019, the increases we project should produce a respectable total return over the 3- to 5-year period.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrecur. gain (losses): '02, (20¢); '03, (7¢); '04, (3¢); '15, (33¢); '17, $1.18; gains on disc. ops.: '02, 6¢; '05, 25¢; '06, 20¢. Next earnings report due early May. **(B)** Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. **(C)** Incl. deferred charges. In '17: $1.42/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net original cost. Rate allowed on com. eq. in OK in '16: 9.5%; in AR in '11: 9.95%; earned on avg. com. eq., '17: 17.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	80

PINNACLE WEST NYSE-PNW

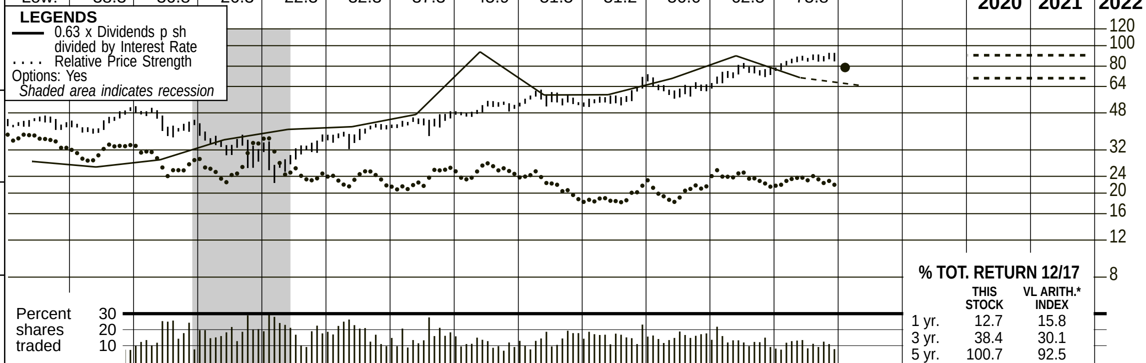
RECENT PRICE **78.86** | P/E RATIO **19.2** (Trailing: 17.0 / Median: 15.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS **1** Raised 1/12/18
SAFETY **1** Raised 5/3/13
TECHNICAL **1** Raised 1/5/18
BETA .70 (1.00 = Market)

High:	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3	82.8	92.5
Low:	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5	75.8

Target Price Range
2020 | 2021 | 2022

LEGENDS
— 0.63 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+15%)	7%
Low	70	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	5	0	0	0	0	12	0
to Sell	4	0	6	0	0	3	0	0	2

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	229	194	218
to Sell	191	224	185
Hld's(000)	105747	107032	104825

Percent shares traded 30 20 10

% TOT. RETURN 12/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.7	15.8
3 yr.	38.4	30.1
5 yr.	100.7	92.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	*32.60*	*33.35*	Revenues per sh	*38.50*
8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	*9.95*	*10.30*	"Cash Flow" per sh	*12.25*
3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	*4.30*	*4.40*	Earnings per sh A	*5.25*
1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	*2.86*	Div'd Decl'd per sh B ■	*3.35*
12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	*12.55*	*11.00*	Cap'l Spending per sh	*10.00*
29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	*44.65*	*46.15*	Book Value per sh C	*51.75*
84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	*112.00*	*112.50*	Common Shs Outst'g D	*114.00*
12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	*19.9*		Avg Ann'l P/E Ratio	*15.0*
.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	*.95*		Relative P/E Ratio	*.95*
3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%		Avg Ann'l Div'd Yield	*4.2%*

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	3498.7	*3550*	*3750*	Revenues ($mill)	*4400*
298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	437.3	442.0	*480*	*500*	Net Profit ($mill)	*615*
33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	33.9%	*33.0%*	*20.0%*	Income Tax Rate	*20.0%*
14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	14.1%	*14.0%*	*11.0%*	AFUDC % to Net Profit	*7.0%*
47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	45.6%	*49.0%*	*47.0%*	Long-Term Debt Ratio	*45.5%*
53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	54.4%	*51.0%*	*53.0%*	Common Equity Ratio	*54.5%*
6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	8825.4	*9820*	*9815*	Total Capital ($mill)	*10800*
8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	11809	12714	*13525*	*14100*	Net Plant ($mill)	*15175*
5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	*9.5%*	*9.5%*	Return on Com Equity E	*10.5%*
2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
70%	96%	89%	66%	68%	58%	58%	62%	59%	62%	*63%*	*64%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $4829.4 mill. **Due in 5 Yrs** $1188.4 mill.
LT Debt $4491.0 mill. **LT Interest** $203.7 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 5.0x)
Leases, Uncapitalized Annual rentals $12.3 mill.
Pension Assets-12/16 $2675.4 mill.
Oblig $3204.5 mill.
Pfd Stock None

Common Stock 111,729,775 shs.
as of 10/27/17
MARKET CAP: $8.8 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.8	+1.3	+.3
Avg. Indust. Use (MWH)	659	658	640
Avg. Indust. Revs. per KWH (¢)	8.26	8.17	8.37
Capacity at Peak (Mw)	9259	9250	9192
Peak Load, Summer (Mw)	7007	7031	7051
Annual Load Factor (%)	48.6	48.3	48.0
% Change Customers (yr-end)	+1.2	+1.3	+1.3
Fixed Charge Cov. (%)	404	438	416

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	- -	.5%	*3.5%*
"Cash Flow"	1.5%	3.5%	*5.5%*
Earnings	3.5%	6.5%	*5.5%*
Dividends	2.5%	3.0%	*5.5%*
Book Value	2.0%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	890.7	1199.1	734.4	3495.4
2016	677.2	915.4	1166.9	739.2	3498.7
2017	677.7	944.6	1183.3	*744.4*	*3550*
2018	*725*	*975*	*1275*	*775*	*3750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.14	1.19	2.20	.05	3.58
2015	.14	1.10	2.30	.37	3.92
2016	.04	1.08	2.35	.47	3.95
2017	.21	1.49	2.46	*.14*	*4.30*
2018	*.20*	*1.30*	*2.60*	*.30*	*4.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.5675	.5675	.5675	.595	2.30
2015	.595	.595	.595	.625	2.41
2016	.625	.625	.625	.655	2.53
2017	.655	.655	.655	.695	2.66
2018					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.2 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 50%; commercial, 40%; industrial, 5%; other, 5%. Generating sources: nuclear, 28%; gas & other, 26%; coal, 20%; purchased, 26%. Fuel costs: 31% of revenues. '16 reported deprec. rate: 2.7%. Has 6,300 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

We estimate that Pinnacle West's earnings will advance modestly in 2018. The company's utility subsidiary, Arizona Public Service, will benefit from a full year's effect of the $94.6 million (3.3%) rate increase that took effect on August 19th. Modest kilowatt-hour sales growth (even after the effects of energy efficiency measures) will likely help, too. Offsetting this will be an increase in expenses associated with planned maintenance outages of fossil (coal or gas) plants. Accordingly, we have trimmed our 2018 earnings estimate by $0.10 a share, to $4.40. Our revised forecast is within Pinnacle West's targeted range of $4.25-$4.45 a share. Meanwhile, our 2017 profit estimate is at the upper end of the company's guidance of $4.15-$4.30 a share.

Two significant capital projects are under construction. APS is adding pollution control equipment to Units 4 and 5 of the Four Corners coal-fired station. This project is on track for completion in the spring of 2018 at a cost of $400 million. These costs will be deferred until the utility can recover them in rates at the start of 2019. APS is also modernizing a gas-fired plant by building five units and shutting two old ones. This will provide a net increase in generating capacity of 290 megawatts. This project is scheduled for completion in the spring of 2019 at a cost of $500 million. Costs here will be deferred until the company receives an order in its next general rate case. This will probably come in mid-2020 after APS puts forth an application in June of 2019.

Finances are strong. The fixed-charge coverage is well above the industry average. The common-equity ratio is healthy, and the company expects no need for additional equity in the next few years. Earned returns on equity have consistently been between 9% and 10% in recent years, and we project they will remain there. Pinnacle West merits a Financial Strength rating of A+.

Timely and high-quality Pinnacle West stock has a dividend yield that is average for a utility. Like most electric utility equities, the recent price is within our 3- to 5-year Target Price Range. Accordingly, total return potential is unspectacular.

Paul E. Debbas, CFA *January 26, 2018*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Div'ds historically pd. in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. In '16: $14.54/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '17: 10%; earned on avg. com. eq., '16: 9.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

PNM RESOURCES NYSE-PNM

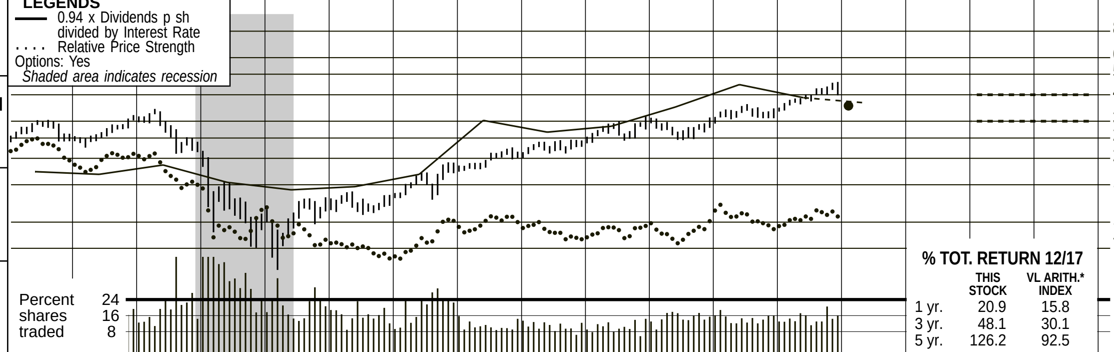
RECENT PRICE **35.55** | P/E RATIO **19.9** (Trailing: 17.8, Median: 18.0) | RELATIVE P/E RATIO **0.96** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS **1** Raised 5/5/17
SAFETY **3** Lowered 5/9/08
TECHNICAL **1** Raised 1/5/18
BETA .75 (1.00 = Market)

High:	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2	36.2	46.0
Low:	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4	29.2	33.3

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+15%)	6%
Low	30	(-15%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	1	0	0	0	0	0
Options	6	0	8	0	0	1	0	0	0
to Sell	2	0	0	0	0	2	0	0	0

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	108	124	119
to Sell	111	95	103
Hld's(000)	84373	83799	82421

% TOT. RETURN 12/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.9	15.8
3 yr.	48.1	30.1
5 yr.	126.2	92.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	*18.50*	*19.15*	Revenues per sh	*21.00*
4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	*5.30*	*5.40*	"Cash Flow" per sh	*6.75*
2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	*1.90*	*1.70*	Earnings per sh A	*2.25*
.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	*1.09*	Div'd Decl'd per sh B ■ †	*1.40*
4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	*6.60*	*6.45*	Cap'l Spending per sh	*6.25*
17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	*21.80*	*22.30*	Book Value per sh C	*24.00*
58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	*79.65*	*79.65*	Common Shs Outst'g D	*79.65*
7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	*20.6*		Avg Ann'l P/E Ratio	*15.5*
.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	*1.00*		Relative P/E Ratio	*.95*
2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $2714.2 mill. **Due in 5 Yrs** $1495.0 mill.
LT Debt $2282.4 mill. **LT Interest** $113.0 mill.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $27.9 mill.
Pension Assets-12/16 $604.2 mill. **Oblig** $688.8 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 10/20/17
MARKET CAP: $2.8 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1363.0	*1475*	*1525*	Revenues ($mill)	*1725*
59.9	8.1	54.0	80.5	97.1	106.1	114.0	116.8	118.8	117.4	*165*	*150*	Net Profit ($mill)	*205*
5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	36.9%	32.4%	*34.0%*	*20.0%*	Income Tax Rate	*20.0%*
--	--	6.3%	7.1%	8.7%	7.1%	1.3%	10.7%	17.0%	11.0%	*8.0%*	*9.0%*	AFUDC % to Net Profit	*6.0%*
42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	55.7%	*56.0%*	*59.0%*	Long-Term Debt Ratio	*58.0%*
57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	*44.0%*	*41.0%*	Common Equity Ratio	*40.0%*
2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	3806.8	*3970*	*4360*	Total Capital ($mill)	*4950*
2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	4904.7	*5160*	*5380*	Net Plant ($mill)	*5875*
3.4%	1.9%	3.2%	4.2%	4.5%	5.1%	5.2%	5.1%	4.8%	4.7%	*5.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
3.5%	.5%	3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	*8.5%*	*7.5%*	Return on Shr. Equity	*9.0%*
3.5%	.5%	3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	*8.5%*	*7.5%*	Return on Com Equity E	*9.0%*
NMF	NMF	.5%	2.2%	3.3%	3.8%	3.8%	3.2%	3.3%	2.8%	*4.0%*	*3.0%*	Retained to Com Eq	*4.0%*
117%	NMF	86%	57%	47%	43%	45%	51%	54%	61%	*48%*	*57%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-2.9	-1.4	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2707	2787	2791
Peak Load, Summer (Mw)	1878	1889	1908
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+.9
Fixed Charge Cov. (%)	236	231	202

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-5.0%	-2.5%	*3.0%*
"Cash Flow"	2.5%	9.5%	*8.0%*
Earnings	-.5%	11.5%	*7.5%*
Dividends	1.0%	10.5%	*9.0%*
Book Value	1.0%	2.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	352.9	417.4	335.9	1439.1
2016	311.0	315.4	400.4	336.2	1363.0
2017	330.2	362.3	419.9	*362.6*	*1475*
2018	*345*	*370*	*440*	*370*	*1525*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.16	.36	.69	.24	1.45
2015	.18	.40	.76	.13	1.48
2016	.13	.34	.68	.31	1.46
2017	.28	.47	.92	*.23*	*1.90*
2018	*.25*	*.39*	*.73*	*.33*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22	.22	.22	.22	.88
2017	.2425	.2425	.2425	.2425	.97
2018	.265				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 520,000 customers in north central New Mexico, incl. Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 247,000 customers in Texas. Electric rev. breakdown: residential, 29%; commercial, 31%; industrial, 18%; other, 22%. Generating sources: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 49% of revenues. '16 depreciation rate: 3.3%. Has 1,800 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, NM 87102-3289. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' utility subsidiary in New Mexico received a disappointing rate order. Public Service Company of New Mexico filed for a rate increase of $99.2 million, based on a 10.125% return on equity. The utility reached a settlement with the commission's staff, the state's attorney general, and most intervenors calling for a $53.2 million hike (before the effects of lower income taxes), based on a 9.575% ROE. However, the commission took the position of an intervenor that was not part of the settlement and modified the agreement to exclude costs associated with an environmental upgrade to the Four Corners coal-fired plant. This might well force the utility to take a nonrecurring charge (estimated at as much as $60 million before taxes, but possibly less). The company asked the regulators to add $4.7 million to the order to clarify an inconsistency with it. The stock price is down more than 15% since the ruling came out on December 20th.

Earnings are likely to decline this year, but should improve materially in 2019. The aforementioned rate hike will be phased in over a two-year period, so PNM will feel the effects of regulatory lag in 2018. Our profit estimate is at the low end of management's targeted range of $1.70-$1.80 a share, which is below its expectation of $1.85-$1.90 for 2017. Because the full increase will be in effect for all of 2019, earnings might well exceed $2.00 a share. The company should also benefit from rate relief in Texas, given that its utility in the Lone Star State plans to file a general rate case in May of 2018. New tariffs are expected to take effect in January of 2019.

The board of directors raised the annual dividend by $0.09 a share (9.3%). The move is effective with the payment in the current quarter. PNM's goal is a payout ratio of 50%-60%.

PNM stock is ranked favorably for Timeliness. However, the dividend yield is low, by utility standards, and total return potential to 2020-2022 is also subpar. And PNM's New Mexico utility operates in a state with a subpar regulatory climate. Note that its appeal of the commission's order in the 2015 general rate case is still pending before the state supreme court.

Paul E. Debbas, CFA *January 26, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28). Excl. gains from disc. ops.: '08, 42¢; '09, 78¢. '15 EPS don't sum due to rounding. Next egs. report due late Feb. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. (C) Incl. intang. In '16: $10.73/sh. (D) In mill., adj. for split. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '18: 9.575%; earn. on avg. com. eq., '16: 7.0%. Reg. Climate: NM, Below Avg.; TX, Avg.

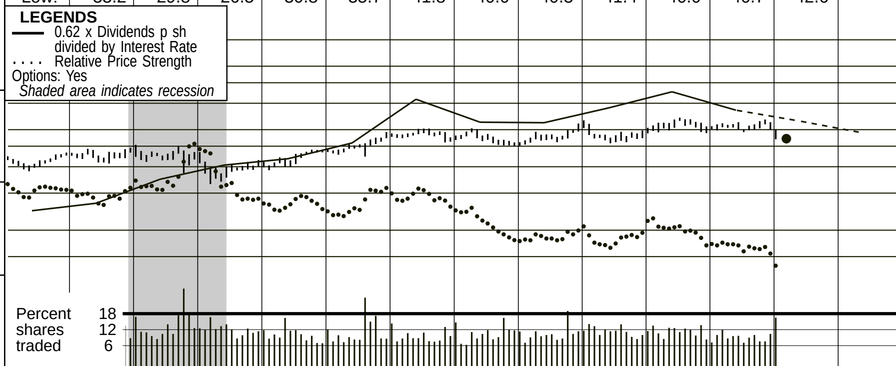
Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	95
Earnings Predictability	70

SOUTHERN COMPANY NYSE-SO

RECENT PRICE 43.49 | P/E RATIO 14.4 (Trailing: 15.2 Median: 16.0) | RELATIVE P/E RATIO 0.75 | DIV'D YLD 5.5% | VALUE LINE

TIMELINESS 4 Lowered 8/11/17
SAFETY 2 Lowered 2/21/14
TECHNICAL 3 Lowered 2/16/18
BETA .55 (1.00 = Market)

High:	39.3	40.6	37.6	38.6	46.7	48.6	48.7	51.3	53.2	54.6	53.5	48.1
Low:	33.2	29.8	26.5	30.8	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.6



Target Price Range 2021 | 2022 | 2023
128 / 96 / 80 / 64 / 48 / 40 / 32 / 24 / 16 / 12

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+50%)	15%
Low	45	(+5%)	7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	3	1	1	0	4	2	1
to Sell	0	1	3	0	1	0	4	2	0

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	572	553	498
to Sell	482	494	514
Hld's(000)	604511	599382	603476

% TOT. RETURN 1/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.4	17.3
3 yr.	2.2	38.0
5 yr.	27.1	85.6

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	*22.50*	*22.45*	*23.50*	Revenues per sh	*26.25*
3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	*6.35*	*6.50*	*6.75*	"Cash Flow" per sh	*7.50*
1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	*3.00*	*3.00*	*3.15*	Earnings per sh A	*3.75*
1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	*2.38*	*2.46*	Div'd Decl'd per sh B ■ †	*2.70*
3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	*8.85*	*8.15*	*7.50*	Cap'l Spending per sh	*7.50*
12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	*23.85*	*24.50*	*25.25*	Book Value per sh C	*28.00*
716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	*1006.0*	*1008.0*	*1010.0*	Common Shs Outst'g D	*1016.0*
14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	*16.6*	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.80	.84	.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	*.80*	*Value Line*		Relative P/E Ratio	*.80*
5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*4.9%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $50126 mill. **Due in 5 Yrs** $16766 mill.
LT Debt $44042 mill. **LT Interest** $1541 mill.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $152 mill.
Pension Assets-12/16$11583 mill.**Ob** $12385 mill.
Pfd Stock $2218 mill. **Pfd Div'd** $45 mill.
Incl. 1 mill. shs. 4.2%-5.44% cum. pfd. ($100 par); 1.52 mill. shs. 5.2%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 4 mill. shs. 5.6%-6.5% noncum. pfd. ($100 par); 8 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 1,003,627,691 shs.
MARKET CAP: $44 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
17127	15743	17456	17657	16537	17087	18467	17489	19896	*22650*	*22850*	*23750*	Revenues ($mill)	*26750*
1807.0	1910.0	2040.0	2268.0	2415.0	2439.0	2567.0	2647.0	2757.0	*3100*	*3145*	*3300*	Net Profit ($mill)	*3845*
33.6%	31.9%	33.5%	35.0%	35.6%	34.8%	33.8%	33.4%	28.5%	*32.5%*	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
12.3%	14.9%	13.7%	10.2%	9.4%	11.6%	13.9%	13.2%	11.9%	*12.0%*	*11.0%*	*11.0%*	AFUDC % to Net Profit	*9.0%*
53.9%	53.2%	51.2%	50.0%	49.9%	51.5%	49.5%	52.8%	61.5%	*63.5%*	*63.5%*	*63.5%*	Long-Term Debt Ratio	*62.0%*
42.6%	43.6%	45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	35.7%	*33.5%*	*34.0%*	*34.0%*	Common Equity Ratio	*35.5%*
31174	34091	35438	37307	38653	41483	42142	46788	69359	*71375*	*72925*	*75225*	Total Capital ($mill)	*80600*
35878	39230	42002	45010	48390	51208	54868	61114	78446	*83950*	*88625*	*92600*	Net Plant ($mill)	*103200*
7.1%	6.9%	7.0%	7.2%	7.3%	6.8%	7.1%	6.6%	4.9%	*5.5%*	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
12.6%	12.0%	11.8%	12.2%	12.5%	12.1%	12.1%	12.0%	10.3%	*12.0%*	*12.0%*	*12.0%*	Return on Shr. Equity	*12.5%*
13.1%	12.4%	12.2%	12.5%	12.8%	12.5%	12.5%	12.6%	11.0%	*12.5%*	*12.5%*	*12.5%*	Return on Com Equity E	*13.0%*
3.5%	3.2%	3.0%	3.4%	3.6%	3.2%	3.2%	3.1%	2.5%	*3.0%*	*2.5%*	*3.0%*	Retained to Com Eq	*3.5%*
74%	75%	77%	73%	73%	75%	75%	76%	78%	*76%*	*78%*	*77%*	All Div'ds to Net Prof	*72%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+3.3	-.7	+.2
Avg. Indust. Use (MWH)	3384	3371	3105
Avg. Indust. Revs. per KWH (¢)	6.37	5.88	6.01
Capacity at Yearend (Mw)	46549	44223	46291
Peak Load, Summer (Mw) F	37234	36794	35781
Annual Load Factor (%)	59.6	59.9	61.5
% Change Customers (yr-end)	+.8	+.9	+1.0
Fixed Charge Cov. (%)	417	433	330

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	1.0%	- -	*4.0%*
"Cash Flow"	3.5%	3.5%	*4.5%*
Earnings	3.0%	3.0%	*4.0%*
Dividends	4.0%	3.5%	*3.5%*
Book Value	5.0%	4.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	4183	4337	5401	3568	17489
2016	3992	4459	6264	5181	19896
2017	5771	5430	6201	*5248*	*22650*
2018	*5850*	*5450*	*6250*	*5300*	*22850*
2019	*6100*	*5650*	*6500*	*5500*	*23750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.56	.71	1.16	.42	2.84
2016	.57	.71	1.22	.33	2.83
2017	.73	.73	1.08	*.46*	*3.00*
2018	*.70*	*.75*	*1.10*	*.45*	*3.00*
2019	*.75*	*.80*	*1.15*	*.45*	*3.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.508	.525	.525	.525	2.08
2015	.525	.5425	.5425	.5425	2.15
2016	.5425	.56	.56	.56	2.22
2017	.56	.58	.58	.58	2.30
2018	.58				

BUSINESS: The Southern Company, through its subs., supplies electricity to 4.6 million customers in GA, AL, FL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.5 mill. customers in GA, FL, NJ, IL, VA, & TN) 7/16. Electric rev. breakdown: residential, 39%; commercial, 31%; industrial, 18%; other, 12%. Retail revs. by state: GA, 49%; AL, 35%; FL, 9%; MS, 7%. Generating sources: gas & oil, 42%; coal, 31%; nuclear, 15%; other, 4%; purchased, 8%. Fuel costs: 30% of revs. '16 reported depr. rate (utility): 3.0%. Has 32,000 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: DE. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, GA 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Southern Company's Georgia Power subsidiary has received permission from the state commission to continue its nuclear construction project. The utility is adding two units at the site of the Vogtle station. Delays and cost overruns added $1.4 billion to the construction cost, making it $8.8 billion. The problem led to the bankruptcy filing of the former contractor, Westinghouse, so its parent, Toshiba, paid Georgia Power $1.7 billion in loan guarantees. Of this amount, $1.5 billion will offset the construction work in progress, and $188 million will be credited to customers. The net effect of all of this is that Southern's earning power will be trimmed by $0.04 a share in 2018. Accordingly, we have lowered our share-earnings estimate by a nickel, to $3.00.

Mississippi Power's regulatory settlement was approved by the state commission. The utility's coal-gasification plant had extensive delays and cost overruns, and is being run as a gas-fired facility. In recent years, the problems forced Mississippi Power to take writedowns, including more than $2.2 billion after taxes in 2017. The settlement resolved all regulatory matters associated with this project, and put an end to the nonrecurring charges.

The sale of two gas utilities is pending. Southern agreed to sell Elizabethtown Gas and Elkton Gas for $1.7 billion. It will use the proceeds to offset some of its equity needs. The sale is expected to be completed by the third quarter of 2018.

We think earnings will advance in 2019. Southern should benefit from rate relief, modest volume growth, and increased income from its Southern Power nonutility subsidiary.

A dividend hike is likely in the second quarter. This is the usual timing of the dividend review. We think Southern will continue the $0.08-a-share annual growth rate it established in 2017. We project the company will maintain this pace over the 3- to 5-year period.

This stock is untimely, but offers an attractive dividend yield. The yield is almost two percentage points above the utility mean. Total return potential through the 2021-2023 period is respectable.

Paul E. Debbas, CFA February 16, 2018

(A) Dil. EPS. Excl. nonrec. gain (losses): '03, 6¢; '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.20). '15 EPS don't sum due to rounding. Next egs. report due late Feb. **(B)** Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. **(C)** Incl. def'd chgs. In '16: $17.26/sh. **(D)** In mill. **(E)** Rate base: AL, MS, fair value; FL, GA, orig. cost. All'd return on com. eq. (blended): 12.5%; earn. on avg. com. eq., '16: 11.8%. Regul. Climate: GA, AL Above Avg.; MS, FL Avg. **(F)** Winter peak in '14 & '15.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	100

EMERA INC. TSE-EMA.TO

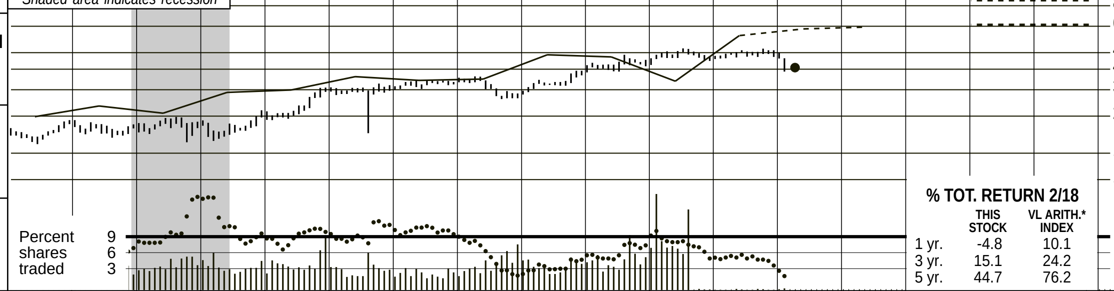
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
40.74	16.2	32.1 / 16.0	0.84	5.5%	VALUE LINE

TIMELINESS 3 Lowered 1/26/18
SAFETY 2 Raised 12/23/16
TECHNICAL 3 Lowered 3/2/18
BETA .60 (1.00 = Market)

High:	23.0	23.8	25.6	32.8	34.3	35.4	37.0	39.4	46.9	50.3	50.0	48.0
Low:	19.0	18.1	18.3	23.0	20.0	32.1	28.9	30.4	38.7	42.0	44.7	39.0

Target Price Range
2021 | 2022 | 2023

LEGENDS
—— 9.0 x "Cash Flow" p sh
. . . . Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+110%)	24%
Low	65	(+60%)	16%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	2	2	5
to Sell	0	2	1
Hld's(000)	890	1994	3629

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.8	10.1
3 yr.	15.1	24.2
5 yr.	44.7	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
11.38	11.37	10.42	10.61	10.51	12.02	11.87	12.75	13.55	16.81	15.72	16.78	20.67	18.95	20.36	27.22	***30.85***	***30.75***	Revenues per sh E	***35.35***
1.96	2.37	2.38	2.52	2.65	2.98	2.75	3.45	3.54	4.11	3.93	4.00	5.20	5.09	3.90	6.43	***6.90***	***7.05***	"Cash Flow" per sh	***8.45***
.84	1.16	1.14	1.10	1.12	1.32	1.26	1.52	1.65	1.97	1.76	1.64	2.82	2.71	1.32	2.74	***2.75***	***2.90***	Earnings per sh A	***4.20***
.86	.86	.88	.89	.89	.90	.97	1.03	1.16	1.31	1.36	1.41	1.48	1.66	2.00	2.13	***2.28***	***2.44***	Div'ds Decl'd per sh C	***3.00***
1.02	1.12	1.39	1.17	1.75	2.26	4.86	2.89	4.60	3.93	3.41	2.42	3.02	2.51	4.91	6.68	***6.50***	***6.20***	Cap'l Spending per sh	***4.90***
12.36	12.12	12.28	12.41	12.69	12.20	13.78	13.31	14.16	11.80	12.60	15.68	18.60	23.71	28.55	34.49	***34.60***	***34.30***	Book Value per sh B	***34.80***
107.80	108.26	108.87	110.10	110.93	111.47	112.21	112.98	114.62	122.83	130.98	132.89	143.78	147.21	210.02	228.77	***230.00***	***234.00***	Common Shs Outst'g D	***246.00***
19.8	14.4	15.9	17.2	18.0	15.7	17.2	14.0	16.1	16.2	19.4	20.1	12.3	15.5	35.2	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	***18.0***
1.08	.82	.84	.92	.97	.83	1.04	.93	1.02	1.02	1.23	1.13	.65	.78	1.85	.86	*Value Line*		Relative P/E Ratio	***1.00***
5.2%	5.1%	4.9%	4.7%	4.4%	4.3%	4.5%	4.8%	4.4%	4.1%	4.0%	4.3%	4.3%	4.0%	4.3%	4.5%	*estimates*		Avg Ann'l Div'd Yield	***4.0%***
						1331.9	1440.2	1553.7	2064.4	2058.6	2230.2	2971.9	2789.3	4277.0	6226.0	***7100***	***7200***	Revenues ($mill)	***8700***
						39.4%	40.8%	38.5%	30.5%	33.5%	34.5%	35.7%	30.8%	26.8%	35.5%	***32.0%***	***32.5%***	Operating Margin	***34.0%***
						165.0	214.2	214.9	263.2	294.4	313.6	341.5	352.2	593.0	856.0	***925***	***950***	Depreciation ($mill)	***1025***
						144.1	175.7	194.2	247.7	231.9	236.8	432.9	427.5	255.0	619.0	***670***	***715***	Net Profit ($mill)	***1070***
						28.6%	21.7%	- -	- -	- -	14.5%	20.1%	17.0%	17.0%	***24.8%***	***21.0%***	***20.0%***	Income Tax Rate	***20.0%***
						10.8%	12.2%	12.5%	12.0%	11.3%	10.6%	14.6%	15.3%	6.0%	9.9%	***9.5%***	***9.9%***	Net Profit Margin	***12.3%***
						d198.3	d88.5	92.2	191.6	d68.0	d368.6	312.0	514.3	d1213	d1420	***d1450***	***d1450***	Working Cap'l ($mill)	***d725***
						2159.2	2454.9	3141.9	3273.5	3201.1	3363.7	3660.3	3750.8	14268	13140	***13075***	***13000***	Long-Term Debt ($mill)	***12700***
						1681.2	1503.5	1773.6	1599.2	2050.4	2608.2	3398.8	4200.1	6704.0	7181	***7950***	***8025***	Shr. Equity ($mill)	***8550***
						5.3%	6.1%	5.7%	6.9%	6.4%	5.5%	7.4%	6.7%	2.8%	***4.5%***	***5.0%***	***5.0%***	Return on Total Cap'l	***7.0%***
						8.6%	11.7%	10.9%	15.5%	11.3%	9.1%	12.7%	10.2%	4.5%	7.8%	***8.5%***	***9.0%***	Return on Shr. Equity	***12.5%***
						2.3%	4.0%	3.6%	5.8%	3.2%	1.5%	7.4%	4.5%	NMF	1.8%	***1.5%***	***1.5%***	Retained to Com Eq	***3.5%***
						75%	66%	70%	66%	77%	87%	55%	63%	124%	78%	***82%***	***84%***	All Div'ds to Net Prof	***71%***

CAPITAL STRUCTURE as of 12/31/17
Total Debt $15122 mill. **Due in 5 Yrs** $2000.0 mill.
LT Debt $13140 mill. **LT Interest** $710.0 mill.
(Total int. coverage:2.0x)
(62% of Cap'l)
Leases, Uncapitalized Annual rentals $31.2 mill.

Pension Assets-12/16 $2208.0 mill
Oblig. $2607.0 mill
Pfd Stock $710.0 mill. **Pfd Div'ds** $28.0 mill.

Common Stock 228,770,000 shs.

MARKET CAP: $9.3 billion (Large Cap)

CURRENT POSITION ($MILL.)	2015	2016	12/31/17
Cash Assets	1073.4	404	438
Receivables	578.1	1014	1083
Inventory (Avg Cst)	314.3	472	418
Other	629.8	621	587
Current Assets	2595.6	2511	2526
Accts Payable	394.2	1242	1161
Debt Due	289.9	1437	1982
Other	1397.2	1045	803
Current Liab.	2081.3	3724	3946

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	6.5%	7.0%	*8.5%*
"Cash Flow"	6.5%	5.0%	*7.5%*
Earnings	7.5%	6.0%	*8.5%*
Dividends	7.0%	8.0%	*8.5%*
Book Value	6.5%	12.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	900.3	537.0	654.0	698.0	2789.3
2016	877.0	499.4	1387.0	1513.6	4277.0
2017	1857	1469	1427	1473	6226
2018	***1900***	***1700***	***1775***	***1725***	***7100***
2019	***1925***	***1725***	***1800***	***1750***	***7200***

Cal-endar	EARNINGS PER SHARE AE Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.07	.24	1.31	2.71
2016	.30	1.38	d.52	.34	1.32
2017	1.48	.47	.38	.41	2.74
2018	***.80***	***.60***	***.70***	***.65***	***2.75***
2019	***.83***	***.63***	***.74***	***.70***	***2.90***

Cal-endar	QUARTERLY DIVIDENDS PAID CE Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.362	.362	.363	.388	1.48
2015	.388	.40	.40	.475	1.66
2016	.475	.475	.5225	.5225	2.00
2017	.5225	.5225	.5225	.565	2.13
2018	.565				

BUSINESS: Emera Inc. is geographically diverse energy and services company. It invests in electricity generation, transmission, and distribution, as well as gas transportation and utility energy services. Also provices energy marketing, trading, and other energy-related mgmt. services. Has investments throughout North America, and in four Caribbean countries. Acquired TECO Energy 7/16. Serves approximately 2,500,000 customers in Florida (45%), New Mexico (22%), Nova Scotia (22%), Maine, and the island of Barbados. Has approximately 7,400 employees. President and CEO: Chris Huskilson. Chairman: Jackie Sheppard. Inc.: Nova Scotia, Canada. Address: 1223 Lower Water St., Halifax, Canada NS B3J 3S8. Telephone: (902) 428-6112. Internet: www.emera.com.

Emera closed out 2017 on an up note. Excluding a one-time $317 million tax revaluation expense, share net came in at $0.41, versus $0.34 in the previous year. The increase was due to a full-year contribution from Florida and New Mexico operations (acquired in 2016), and higher contributions from its Maritime Link and Labrador Island Link investments.

The Emera Florida and New Mexico segment will likely remain the key performance driver in 2018. Adjusted net income for the division rose 27% in the December quarter, to $80 million, accounting for 58% of the company total. Further gains are likely this year, driven by higher base revenues related to completion of the Polk Power Station expansion project, as well as customer and load growth. Altogether, management looks for segment earnings to rise about 10% this year.

The company continues to make good progress on its various project initiatives. The Maritime Link connecting Newfoundland and Nova Scotia with two 170-kilometer subsea cables began commercial operation in January. Meanwhile, the Labrador Island Link is slated to come into service in the second quarter. Elsewhere, Emera started work on its 600 megawatt solar base rate project in Florida. The first 150 mws should be installed and commissioned this year, resulting in a $30 million U.S. revenue increase. Another 450 mw are slated for 2019 through 2021, and the company is actively pursuing additional solar projects.

U.S. tax reform will weigh on 2018 earnings growth. Management looks for earnings to be clipped by $25 million to $30 million due to the tax effect on U.S.-denominated debt. Management is looking at a number of alternatives to minimize the earnings impact going forward. Altogether, we've trimmed our 2018 share-earnings estimate by $0.20, to $2.75. At the same time, we are introducing our 2019 call at $2.90.

These shares have long-term appeal. The combination of above-average 3- to 5-year appreciation potential and a good yield, along with an attractive risk profile (Safety 2, Stock Price Stability 100), should be of particular interest to conservative, buy-and-hold investors.

Mario Ferro *March 23, 2018*

(A) Diluted earnings. 2016 earnings do not sum due to change in share count. Excludes non-recurring charge: 2017: $1.47. Next earnings report due early May.
(B) Incl. intangibles. In 2017, $5.8 bill., or $25.37 per share. (C) Common div. historically paid in the middle of Feb., May, August, and Nov.
(D) In millions.
(E) All data in Canadian dollars.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	55

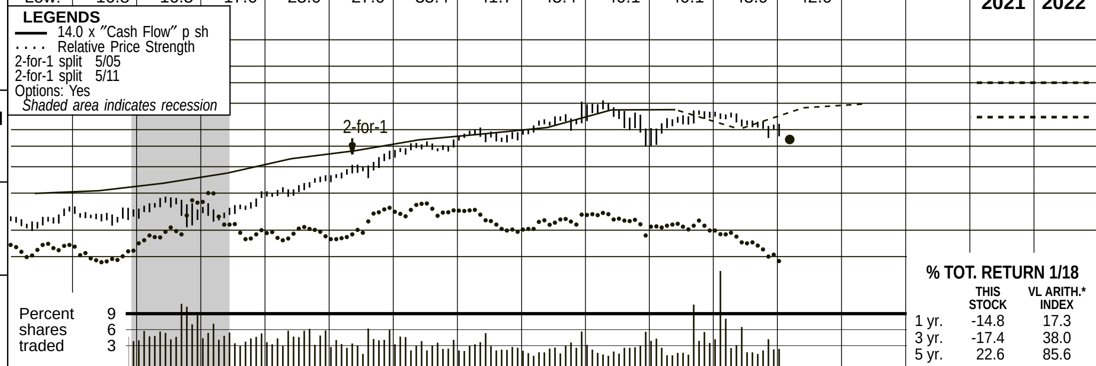
ENBRIDGE INC. TSE-ENB.TO AB

RECENT PRICE 43.06 | P/E RATIO 18.2 (Trailing: 21.7, Median: 22.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 6.2% | VALUE LINE

High:	20.7	23.1	24.5	29.1	38.2	43.1	49.2	65.1	66.0	59.2	58.3	51.1
Low:	16.8	16.5	17.6	23.0	27.0	35.4	41.7	45.4	40.1	40.1	43.9	42.0

TIMELINESS 3 Raised 3/2/18
SAFETY 3 Lowered 6/2/17
TECHNICAL 3 Raised 2/2/18
BETA 1.00 (1.00 = Market)

LEGENDS
—— 14.0 x "Cash Flow" p sh
.... Relative Price Strength
2-for-1 split 5/05
2-for-1 split 5/11
Options: Yes
Shaded area indicates recession



Target Price Range

2021	2022	2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+85%)	21%
Low	55	(+30%)	11%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	758	319	311
to Sell	69	400	367
Hld's(000)	1036232	1018591	1029556

% TOT. RETURN 1/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.8	17.3
3 yr.	-17.4	38.0
5 yr.	22.6	85.6

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
6.70	7.33	9.45	12.11	15.13	16.17	21.62	16.49	20.44	25.83	32.78	40.84	45.41	39.90	36.65	26.18	**28.25**	**28.30**	Revenues per sh A	**29.70**
1.16	1.44	1.69	1.62	1.71	1.76	1.91	2.14	2.50	2.73	3.07	3.27	3.51	4.25	4.27	**3.45**	**4.35**	**4.55**	"Cash Flow" per sh	**5.35**
.63	.77	.96	.82	.90	.98	1.06	1.18	1.33	1.48	1.62	1.78	1.90	2.20	2.28	1.96	**2.50**	**2.55**	Earnings per sh C	**2.95**
.38	.42	.46	.52	.58	.62	.66	.74	.85	.98	1.13	1.26	1.40	1.86	2.12	2.41	**2.68**	**2.76**	Div'ds Decl'd per sh D■	**2.96**
1.08	.59	.72	.98	1.68	3.12	4.87	4.39	3.19	3.35	7.08	10.22	12.69	6.18	5.44	4.89	**4.10**	**4.15**	Cap'l Spending per sh	**4.05**
4.68	5.24	5.57	5.94	6.38	6.99	8.70	9.44	10.05	10.37	8.80	10.37	12.39	14.62	14.99	29.73	**29.60**	**30.10**	Book Value per sh E	**32.40**
678.80	662.00	692.40	697.80	703.60	737.00	746.00	756.00	740.00	751.00	772.00	806.00	829.00	847.00	943.00	1695.00	**1700.00**	**1800.00**	Common Shs Outst'g F	**2100.00**
17.8	15.6	13.6	20.8	20.0	19.1	19.6	17.3	19.2	21.3	24.3	25.3	27.2	25.6	23.1	26.8	*Bold figures are*		Avg Ann'l P/E Ratio	**23.0**
.97	.89	.72	1.11	1.08	1.01	1.18	1.15	1.22	1.34	1.55	1.42	1.43	1.29	1.21	1.40	*Value Line*		Relative P/E Ratio	**1.30**
3.4%	3.5%	3.5%	3.1%	3.2%	3.3%	3.2%	3.6%	3.3%	3.1%	2.9%	2.8%	2.7%	3.3%	4.0%	4.6%	*estimates*		Avg Ann'l Div'd Yield	**4.4%**

CAPITAL STRUCTURE as of 12/31/17
Total Debt $65.180 bill. **Due in 5 Yrs** $12.8 bill.
LT Debt $60.865 bill. **LT Interest** $2.556 bill.
(Total interest coverage: 2.7x) (51% of Capital)

Leases, Uncapitalized: $91.0 mill.
Pension Assets-12/17 $4.7 bill.
Oblig. $5.3 bill.

Pfd. Stock $7747.0 mill. **Pfd. Div'd.** $330.0 mill.
(13% of Capital)
Common Stock 1,695,190,292 shares
as of 2/9/18
MARKET CAP: $73.0 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
16131	12466	15127	19402	25306	32918	37641	33794	34560	44378	**48000**	**50900**	Revenues ($mill) A	**62355**
12.6%	16.2%	15.7%	15.5%	13.4%	12.1%	13.9%	17.1%	17.9%	**19.7%**	**22.3%**	**23.0%**	Operating Margin	**24.5%**
658.4	764.0	864.0	937.0	1206.0	1370.0	1577.0	2024.0	2240.0	3163.0	**3500**	**4000**	Depreciation ($mill)	**5500**
771.7	857.4	991.0	1117.0	1269.0	1446.9	1574.0	1866.0	2078.0	**3000**	**4250**	**4590**	Net Profit ($mill)	**6165**
32.4%	16.8%	21.0%	36.0%	12.8%	20.1%	23.2%	8.9%	5.2%	**NMF**	**5.0%**	**7.0%**	Income Tax Rate	**7.0%**
4.8%	6.9%	6.6%	5.8%	5.0%	4.4%	4.2%	5.5%	6.0%	**6.8%**	**8.9%**	**9.0%**	Net Profit Margin	**9.9%**
d397.6	d194.0	406.0	d565.0	d469.0	d3778	d1300	d3217	d4556	d5409	**d5565**	**d4595**	Working Cap'l ($mill)	**7225**
11629	12974	14622	15208	20203	22357	33423	39540	36494	60865	**65000**	**66000**	Long-Term Debt ($mill)	**75000**
6618.8	7261.0	7565.0	8841.0	10500	13496	16786	18898	21386	58135	**57695**	**61540**	Shr. Equity ($mill) E	**75560**
5.6%	5.6%	6.0%	6.0%	5.4%	5.2%	4.2%	4.5%	5.0%	**2.5%**	**3.5%**	**3.5%**	Return on Total Cap'l	**4.0%**
11.7%	11.8%	13.1%	12.6%	12.1%	10.7%	9.4%	9.9%	9.7%	5.1%	**7.5%**	**7.5%**	Return on Shr. Equity	**8.0%**
4.2%	6.1%	7.5%	7.5%	8.3%	7.1%	5.6%	5.1%	4.5%	- -	**Nil**	**Nil**	Retained to Com Eq	**Nil**
64%	49%	44%	48%	55%	59%	63%	66%	69%	103%	**115%**	**116%**	All Div'ds to Net Prof	**107%**

CURRENT POSITION ($mill.)

	2015	2016	12/31/17
Cash Assets	1015	2117	587
Receivables & Other	5437	4992	7100
Inventory (Fair Value)	1145	1301	1528
Current Assets	7597	8410	9215
Payables & Other	7723	7750	10269
Debt Due	2950	5074	4315
Other	141	142	40
Current Liab.	10814	12966	14624

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	13.0%	14.0%	-2.5%
"Cash Flow"	9.0%	10.5%	4.5%
Earnings	9.0%	10.0%	5.5%
Dividends	13.0%	16.0%	5.5%
Book Value	9.0%	7.0%	8.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	7929	8631	8320	8914	33794
2016	8795	7939	8488	9338	34560
2017	11146	11116	9227	12889	44378
2018	*12050*	*12020*	*10130*	*13800*	*48000*
2019	*12775*	*12745*	*10855*	*14525*	*50900*

Cal-endar	EARNINGS PER SHARE AC Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.56	.60	.47	.58	2.20
2016	.76	.50	.47	.56	2.28
2017	.57	.41	.39	.61	1.96
2018	*.70*	*.54*	*.52*	*.74*	*2.50*
2019	*.72*	*.55*	*.53*	*.75*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID D■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.35	.35	.35	.35	1.40
2015	.465	.465	.465	.465	1.86
2016	.53	.53	.53	.53	2.12
2017	.583	.61	.61	.61	2.41
2018	.671				

BUSINESS: Enbridge Inc., is a leader in energy transportation and distribution in North America and intl. As a transporter of energy, it operates the world's longest crude oil and liquids pipeline system. The company also has international oper. and a growing involvement in natural gas transmission and midstream businesses. As a distributor of energy, it owns and operates Canada's largest natural gas distribution company, and provides services in Ontario, Quebec, New Brunswick, and New York State. Owns 38.9% of Noverco. In '17, Merged with Spectra Energy Corp. (SE). Emplys. 8,600. President & Chief Executive Officer: Albert Monaco. Inc.: Canada. Addr.: 3000, 425 - 1st Street S.W., Calgary, Alberta, Canada T2P 3L8. Tel.: 403-231-3900. Internet: www.enbridge.com.

Since our December review, shares of Enbridge Inc. continue to trend lower. The stock's price fell about 6% over that time frame. At this point, ENB.TO's quotation has receded more than 25% from the highs experienced in 2017.

Meanwhile, the company posted a mixed bag of financial results for 2017. On the upside, revenues increased 28.4% on a year-over-year basis, to $44.378 billion. This reflected greater system throughput at the Liquids Pipeline division thanks to improved volumes on the Canadian Mainline, Lakehead, and Regional Oil Sands systems. Despite this uptick in volumes, the company issued a fair amount of shares needed to facilitate the Spectra merger. To recap, to complete the deal, Spectra Energy Corp. (SE) shareholders received 0.984 shares of the newly formed entity, now called Enbridge Inc. This effectively represented a tender offer price of $40.33 per share (based on ENB.TO's price prior to the merger's announcement). This transaction was completed in early 2017, and left ENB.TO shareholders owning roughly 57% of the largest energy infrastructure company in North America. However, the large level of stock issuances did have a dilutive effect on share net, which fell about 14%, to $1.96 last year. This was in line with our call of $2.00.

The newly formed entity appears poised to register a healthy 8% revenue gain this year, to $48.0 billion. The recent merger brought together expansive liquid and natural gas franchises in the United States and Canada. Those efforts should be further benefited by $8.2 billion in capital projects put into service last year, and an estimated $7.0 billion in growth initiatives in 2018. Combined, we look for ENB.TO's bottom line to advance roughly 28%, to $2.50 a share, this year. Finally, we have introduced our 2019 revenue and earnings estimates at $50.9 billion and $2.55 a share, respectively.

Our Timeliness Ranking System suggests these shares will mirror the year-ahead broader market averages. What's more, the shifting around of assets provides a bit of uncertainty here. That said, recovery potential and an above-average payout may entice some accounts.

Bryan J. Fong *March 2, 2018*

(A) All figures in CAD. (B) Also trades on the NYSE ('ENB'). (C) Canadian GAAP. Dil. egs. Qtly. figures may not sum due to rounding. Excludes nonrec. gains/(losses): '08, $1.53; '09, $1.92; '10, (0.09¢); '11, (0.18¢) Next earnings report due early May. (D) Divs. paid in March, June, Sept., and Dec. Subject to 15% nonresident withholding tax. ■ Reinvestment plan avail. Participants receive a 2% discount on shares purchased with reinv. dividends. (E) Inc. intang. In '17: $37724.0 million, $22.26 a share. (F) In millions, adj. for splits.

Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	65
Earnings Predictability	85

Yahoo Growth Rates

S&P 500	Dow 30	Nasdaq	Russell 2000
2,640.87	24,103.11	7,063.44	1,529.43
+35.87 (+1.38%)	+254.69 (+1.07%)	+114.22 (+1.64%)	+16.40 (+1.08%)




ALLETE, Inc. (ALE)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist

Quote Lookup

72.25 +0.42 (+0.58%)

At close: March 29 4:02PM EDT

Buy Sell

Click here to start trading

Summary Chart Conversations Statistics ... ptions Holders Historical Data Analysts Sustainability NEW

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	4	6	6
Avg. Estimate	0.98	0.72	3.4	3.67
Low Estimate	0.92	0.67	3.23	3.41
High Estimate	1.02	0.76	3.5	3.79
Year Ago EPS	0.97	0.72	3.19	3.4

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	4	4
Avg. Estimate	377M	365M	1.48B	1.54B
Low Estimate	355M	342M	1.41B	1.43B
High Estimate	399M	388M	1.58B	1.7B
Year Ago Sales	365.6M	353.3M	1.42B	1.48B
Sales Growth (year/est)	3.10%	3.30%	4.40%	3.60%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.94	0.55	0.94	0.73
EPS Actual	0.97	0.72	0.72	0.78
Difference	0.03	0.17	-0.22	0.05
Surprise %	3.20%	30.90%	-23.40%	6.80%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.98	0.72	3.4	3.67
7 Days Ago	0.98	0.72	3.4	3.67
30 Days Ago	0.98	0.73	3.39	3.61

People Also Watch

Symbol	Last Price	Change	% Change
LNT Alliant Energy Corporation	40.86	+0.24	+0.59%
AVA Avista Corporation	51.25	-0.33	-0.64%
BKH Black Hills Corporation	54.30	+0.34	+0.63%
IDA IDACORP, Inc.	88.27	+0.66	+0.75%
EE El Paso Electric Company	51.00	+0.40	+0.79%

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	2	2	1	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	ALE	Industry	Sector	S&P 500
Current Qtr.	1.00%	N/A	N/A	0.36
Next Qtr.	N/A	N/A	N/A	0.37
Current Year	6.60%	N/A	N/A	0.20
Next Year	7.90%	N/A	N/A	0.11
Next 5 Years (per annum)	6.00%	N/A	N/A	0.12
Past 5 Years (per annum)	3.82%	N/A	N/A	N/A

Alliant Energy Corporation (LNT)

Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

40.86 +0.24 (+0.59%)

At close: March 29 4:03PM EDT

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	5	7	8
Avg. Estimate	0.53	0.42	2.11	2.24
Low Estimate	0.45	0.37	2.1	2.2
High Estimate	0.69	0.45	2.13	2.27
Year Ago EPS	0.44	0.41	1.93	2.11

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	5	6
Avg. Estimate	977.99M	750.22M	3.5B	3.64B
Low Estimate	865.42M	724.97M	3.43B	3.52B
High Estimate	1.09B	775.47M	3.61B	3.77B
Year Ago Sales	853.9M	765.3M	3.38B	3.5B
Sales Growth (year/est)	14.50%	-2.00%	3.60%	4.00%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.43	0.38	0.86	0.36
EPS Actual	0.44	0.41	0.75	0.33
Difference	0.01	0.03	-0.11	-0.03
Surprise %	2.30%	7.90%	-12.80%	-8.30%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.53	0.42	2.11	2.24
7 Days Ago	0.53	0.42	2.11	2.24
30 Days Ago	0.52	0.42	2.11	2.23

People Also Watch

Symbol	Last Price	Change	% Change
WEC WEC Energy Group, Inc.	62.70	+0.42	+0.67%
WR Westar Energy, Inc.	52.59	+0.65	+1.25%
OGE OGE Energy Corporation	32.77	+0.44	+1.36%
PNW Pinnacle West Capital Corporati	79.80	+0.33	+0.42%
SCG SCANA Corporation	37.55	+0.22	+0.59%

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	1	1	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	LNT	Industry	Sector	S&P 500
Current Qtr.	20.50%	N/A	N/A	0.36
Next Qtr.	2.40%	N/A	N/A	0.37
Current Year	9.30%	N/A	N/A	0.20
Next Year	6.20%	N/A	N/A	0.11
Next 5 Years (per annum)	5.45%	N/A	N/A	0.12
Past 5 Years (per annum)	4.13%	N/A	N/A	N/A

American Electric Power Company, Inc. (AEP)

Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

68.59 -0.07 (-0.10%)

At close: March 29 4:03PM EDT

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	10	8	19	18
Avg. Estimate	1	0.83	3.89	4.12
Low Estimate	0.97	0.75	3.84	4.02
High Estimate	1.03	0.99	3.96	4.21
Year Ago EPS	0.96	0.75	3.68	3.89

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	6	5	12	11
Avg. Estimate	4.06B	3.98B	15.88B	16.35B
Low Estimate	3.73B	3.66B	14.21B	14.55B
High Estimate	4.3B	4.28B	17.14B	17.73B
Year Ago Sales	3.9B	3.6B	15.4B	15.88B
Sales Growth (year/est)	4.20%	10.50%	3.10%	3.00%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.95	0.82	1.16	0.79
EPS Actual	0.96	0.75	1.1	0.85
Difference	0.01	-0.07	-0.06	0.06
Surprise %	1.10%	-8.50%	-5.20%	7.60%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	1	0.83	3.89	4.12
7 Days Ago	1	0.83	3.89	4.12
30 Days Ago	1.01	0.83	3.89	4.12

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	1	N/A
Up Last 30 Days	N/A	N/A	1	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	AEP	Industry	Sector	S&P 500
Current Qtr.	4.20%	N/A	N/A	0.36
Next Qtr.	10.70%	N/A	N/A	0.37
Current Year	5.70%	N/A	N/A	0.20
Next Year	5.90%	N/A	N/A	0.11
Next 5 Years (per annum)	5.63%	N/A	N/A	0.12
Past 5 Years (per annum)	4.92%	N/A	N/A	N/A

Duke Energy Corporation (DUK)

Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

77.47 +0.05 (+0.06%)

At close: March 29 4:04PM EDT

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	10	9	16	16
Avg. Estimate	1.04	0.98	4.69	4.95
Low Estimate	0.56	0.79	4.6	4.79
High Estimate	1.27	1.09	4.78	5.04
Year Ago EPS	1.04	1.01	4.57	4.69

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	7	7	12	11
Avg. Estimate	5.68B	5.58B	24.07B	24.46B
Low Estimate	4.82B	5.25B	22.93B	22.4B
High Estimate	6.14B	5.93B	25.64B	26.87B
Year Ago Sales	5.73B	5.55B	23.57B	24.07B
Sales Growth (year/est)	-0.90%	0.40%	2.20%	1.60%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	1.03	1.01	1.55	0.92
EPS Actual	1.04	1.01	1.59	0.94
Difference	0.01	0	0.04	0.02
Surprise %	1.00%	0.00%	2.60%	2.20%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	1.04	0.98	4.69	4.95
7 Days Ago	1.03	0.98	4.7	4.95
30 Days Ago	1.04	1	4.73	4.97

People Also Watch

Symbol	Last Price	Change	% Change
SO Southern Company (The)	44.66	+0.02	+0.04%
D Dominion Energy, Inc.	67.43	-0.36	-0.53%
AEP American Electric Power Company	68.59	-0.07	-0.10%
ED Consolidated Edison, Inc.	77.94	+0.38	+0.49%
SE Sea Limited American Depositary	11.27	+0.34	+3.11%

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	1	N/A	N/A	N/A
Up Last 30 Days	1	N/A	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	1	1	1

Growth Estimates	DUK	Industry	Sector	S&P 500
Current Qtr.	N/A	N/A	N/A	0.36
Next Qtr.	-3.00%	N/A	N/A	0.37
Current Year	2.60%	N/A	N/A	0.20
Next Year	5.50%	N/A	N/A	0.11
Next 5 Years (per annum)	4.24%	N/A	N/A	0.12
Past 5 Years (per annum)	3.01%	N/A	N/A	N/A

Edison International (EIX)

Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

63.66 +0.59 (+0.94%)

At close: March 29 4:01PM EDT

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	9	9	13	13
Avg. Estimate	0.97	0.92	4.08	4.55
Low Estimate	0.71	0.72	3.86	4.37
High Estimate	1.35	1.49	4.25	4.69
Year Ago EPS	1.1	0.85	4.5	4.08

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	5	10	11
Avg. Estimate	2.54B	2.92B	12.61B	13.04B
Low Estimate	2.07B	2.62B	11.95B	12.39B
High Estimate	2.86B	3.11B	13.65B	14.2B
Year Ago Sales	2.46B	2.96B	12.32B	12.61B
Sales Growth (year/est)	3.30%	-1.40%	2.30%	3.40%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.9	0.92	1.33	0.92
EPS Actual	1.1	0.85	1.43	1.1
Difference	0.2	-0.07	0.1	0.18
Surprise %	22.20%	-7.60%	7.50%	19.60%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.97	0.92	4.08	4.55
7 Days Ago	0.98	0.93	4.1	4.55
30 Days Ago	1.03	0.95	4.25	4.58

People Also Watch

Symbol	Last Price	Change	% Change
PCG Pacific Gas & Electric Co.	43.93	+0.69	+1.60%
ETR Entergy Corporation	78.78	-0.22	-0.28%
FE FirstEnergy Corporation	34.01	-0.38	-1.10%
SRE Sempra Energy	111.22	+0.89	+0.81%
DTE DTE Energy Company	104.40	+0.40	+0.38%

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	1	1	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	1	1	1

Growth Estimates	EIX	Industry	Sector	S&P 500
Current Qtr.	-11.80%	N/A	N/A	0.36
Next Qtr.	8.20%	N/A	N/A	0.37
Current Year	-9.30%	N/A	N/A	0.20
Next Year	11.50%	N/A	N/A	0.11
Next 5 Years (per annum)	2.62%	N/A	N/A	0.12
Past 5 Years (per annum)	-0.00%	N/A	N/A	N/A

U.S. Markets closed

S&P 500	Dow 30	Nasdaq	Russell 2000
2,640.87	24,103.11	7,063.44	1,529.43
+35.87 (+1.38%)	+254.69 (+1.07%)	+114.22 (+1.64%)	+16.40 (+1.08%)




Eversource Energy (ES)

Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

58.92 +0.45 (+0.77%)

At close: March 29 4:02PM EDT

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	8	7	13	14
Avg. Estimate	0.86	0.75	3.25	3.48
Low Estimate	0.78	0.72	3.18	3.41
High Estimate	0.91	0.77	3.3	3.59
Year Ago EPS	0.82	0.72	3.11	3.25

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	3	3	8	9
Avg. Estimate	2.14B	1.81B	7.86B	8.08B
Low Estimate	2.06B	1.76B	7.36B	7.73B
High Estimate	2.18B	1.84B	8.49B	8.71B
Year Ago Sales	2.11B	1.76B	7.75B	7.86B
Sales Growth (year/est)	1.60%	2.50%	1.40%	2.70%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.82	0.67	0.83	0.75
EPS Actual	0.82	0.72	0.82	0.75
Difference	0	0.05	-0.01	0
Surprise %	0.00%	7.50%	-1.20%	0.00%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.86	0.75	3.25	3.48
7 Days Ago	0.86	0.75	3.25	3.48
30 Days Ago	0.88	0.74	3.3	3.51

People Also Watch

Symbol	Last Price	Change	% Change
WEC WEC Energy Group, Inc.	62.70	+0.42	+0.67%
NEE NextEra Energy, Inc.	163.33	+1.06	+0.65%
SCG SCANA Corporation	37.55	+0.22	+0.59%
LNT Alliant Energy Corporation	40.86	+0.24	+0.59%
EIX Edison International	63.66	+0.59	+0.94%

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	1	1	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	ES	Industry	Sector	S&P 500
Current Qtr.	4.90%	N/A	N/A	0.36
Next Qtr.	4.20%	N/A	N/A	0.37
Current Year	4.50%	N/A	N/A	0.20
Next Year	7.10%	N/A	N/A	0.11
Next 5 Years (per annum)	5.65%	N/A	N/A	0.12
Past 5 Years (per annum)	5.52%	N/A	N/A	N/A

OGE Energy Corp. (OGE)

NYSE - NYSE Delayed Price. Currency in USD

32.77 +0.44 (+1.36%)

At close: March 29 4:06PM EDT

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	5	7	6
Avg. Estimate	0.14	0.44	2	2.11
Low Estimate	0.06	0.23	1.95	2.05
High Estimate	0.2	0.59	2.03	2.15
Year Ago EPS	0.18	0.52	1.92	2

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	4	4
Avg. Estimate	463.95M	604.77M	2.3B	2.44B
Low Estimate	455.43M	602.86M	2.28B	2.35B
High Estimate	472.46M	606.67M	2.33B	2.64B
Year Ago Sales	456M	586.4M	2.26B	2.3B
Sales Growth (year/est)	1.70%	3.10%	1.90%	5.90%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.15	0.47	0.94	0.28
EPS Actual	0.18	0.52	0.92	0.3
Difference	0.03	0.05	-0.02	0.02
Surprise %	20.00%	10.60%	-2.10%	7.10%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.14	0.44	2	2.11
7 Days Ago	0.14	0.44	2	2.11
30 Days Ago	0.11	0.52	2.05	2.15

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	2	2	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	OGE	Industry	Sector	S&P 500
Current Qtr.	-22.20%	N/A	N/A	0.36
Next Qtr.	-15.40%	N/A	N/A	0.37
Current Year	4.20%	N/A	N/A	0.20
Next Year	5.50%	N/A	N/A	0.11
Next 5 Years (per annum)	5.80%	N/A	N/A	0.12
Past 5 Years (per annum)	5.45%	N/A	N/A	N/A

Pinnacle West Capital Corporation (PNW)

Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

79.80 +0.33 (+0.42%)

At close: March 29 4:05PM EDT

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	10	9	14	14
Avg. Estimate	0.16	1.47	4.46	4.7
Low Estimate	0.02	1.25	4.45	4.58
High Estimate	0.32	1.6	4.49	4.79
Year Ago EPS	0.21	1.49	4.35	4.46

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	4	4	9	10
Avg. Estimate	702.52M	957.42M	3.64B	3.75B
Low Estimate	675.75M	933.65M	3.48B	3.59B
High Estimate	757.15M	975.7M	3.97B	4.16B
Year Ago Sales	677.73M	944.59M	3.57B	3.64B
Sales Growth (year/est)	3.70%	1.40%	2.00%	3.20%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.16	1.17	2.32	0.12
EPS Actual	0.21	1.49	2.46	0.19
Difference	0.05	0.32	0.14	0.07
Surprise %	31.20%	27.40%	6.00%	58.30%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.16	1.47	4.46	4.7
7 Days Ago	0.16	1.47	4.46	4.7
30 Days Ago	0.2	1.49	4.41	4.7

People Also Watch

Symbol	Last Price	Change	% Change
NI NiSource Inc	23.91	+0.19	+0.80%
SCG SCANA Corporation	37.55	+0.22	+0.59%
DTE DTE Energy Company	104.40	+0.40	+0.38%
PEG Public Service Enterprise Group	50.24	+0.88	+1.78%
TE TECO Energy, Inc.	27.64	-0.01	0.00%

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	4	6	12	4
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	1	N/A

Growth Estimates	PNW	Industry	Sector	S&P 500
Current Qtr.	-23.80%	N/A	N/A	0.36
Next Qtr.	-1.30%	N/A	N/A	0.37
Current Year	2.50%	N/A	N/A	0.20
Next Year	5.40%	N/A	N/A	0.11
Next 5 Years (per annum)	3.63%	N/A	N/A	0.12
Past 5 Years (per annum)	10.03%	N/A	N/A	N/A

PNM Resources, Inc. (PNM)

Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

38.25 -0.05 (-0.13%)

At close: March 29 4:00PM EDT

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	6	5	7	9
Avg. Estimate	0.24	0.47	1.84	2.07
Low Estimate	0.21	0.43	1.7	2
High Estimate	0.28	0.5	1.88	2.1
Year Ago EPS	0.28	0.49	1.94	1.84

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	3	3	4	5
Avg. Estimate	292.94M	360.71M	1.47B	1.5B
Low Estimate	209.26M	340M	1.45B	1.46B
High Estimate	335M	375.44M	1.48B	1.53B
Year Ago Sales	330.18M	362.32M	1.45B	1.47B
Sales Growth (year/est)	-11.30%	-0.40%	1.60%	1.90%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.24	0.45	0.85	0.19
EPS Actual	0.28	0.49	0.93	0.24
Difference	0.04	0.04	0.08	0.05
Surprise %	16.70%	8.90%	9.40%	26.30%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.24	0.47	1.84	2.07
7 Days Ago	0.24	0.47	1.84	2.07
30 Days Ago	0.22	0.46	1.76	2.05

People Also Watch

Symbol	Last Price	Change	% Change
PNW Pinnacle West Capital Corporati	79.80	+0.33	+0.42%
EE El Paso Electric Company	51.00	+0.40	+0.79%
IDA IDACORP, Inc.	88.27	+0.66	+0.75%
OGE OGE Energy Corporation	32.77	+0.44	+1.36%
POR Portland General Electric Co	40.51	+0.23	+0.57%

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	3	3	5	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	PNM	Industry	Sector	S&P 500
Current Qtr.	-14.30%	N/A	N/A	0.36
Next Qtr.	-4.10%	N/A	N/A	0.37
Current Year	-5.20%	N/A	N/A	0.20
Next Year	12.50%	N/A	N/A	0.11
Next 5 Years (per annum)	5.80%	N/A	N/A	0.12
Past 5 Years (per annum)	13.11%	N/A	N/A	N/A

The Southern Company (SO)

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NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

44.66 +0.02 (+0.04%)

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Buy Sell

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Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	10	8	16	16
Avg. Estimate	0.81	0.64	2.9	3.04
Low Estimate	0.73	0.55	2.84	2.97
High Estimate	0.86	0.74	2.97	3.14
Year Ago EPS	0.66	0.73	3.02	2.9

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	8	7	13	12
Avg. Estimate	5.91B	5.24B	22.5B	23.15B
Low Estimate	5.47B	4.8B	20.68B	21.46B
High Estimate	6.57B	5.82B	24.15B	24.97B
Year Ago Sales	5.77B	5.43B	23.03B	22.5B
Sales Growth (year/est)	2.40%	-3.60%	-2.30%	2.90%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.6	0.71	1.07	0.46
EPS Actual	0.66	0.73	1.12	0.51
Difference	0.06	0.02	0.05	0.05
Surprise %	10.00%	2.80%	4.70%	10.90%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.81	0.64	2.9	3.04
7 Days Ago	0.81	0.64	2.9	3.05
30 Days Ago	0.7	0.73	2.99	3.1

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	1	1	N/A	N/A
Up Last 30 Days	5	1	2	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	1	1

Growth Estimates	SO	Industry	Sector	S&P 500
Current Qtr.	22.70%	N/A	N/A	0.36
Next Qtr.	-12.30%	N/A	N/A	0.37
Current Year	-4.00%	N/A	N/A	0.20
Next Year	4.80%	N/A	N/A	0.11
Next 5 Years (per annum)	2.70%	N/A	N/A	0.12
Past 5 Years (per annum)	2.45%	N/A	N/A	N/A

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(•) Canadian Markets are closed

S&P/TSX	S&P 500	DOW	CAD/USD	CRUDE OIL	BTC-C
15,367.29	2,640.87	24,103.11	0.78	65.04	8,918.8
+197.35 (+1.30%)	+35.87 (+1.38%)	+254.69 (+1.07%)	+0.00 (+0.02%)	+0.10 (+0.15%)	-285.43 (

Canadian Utilities Limited (CU.TO)

☆ Add to watchlist

Toronto - Toronto Delayed Price. Currency in CAD

Quote Lookup

34.39 -0.37 (-1.06%)

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Currency in CAD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	4	6	6
Avg. Estimate	0.76	0.5	2.33	2.43
Low Estimate	0.71	0.48	2.29	2.37
High Estimate	0.81	0.53	2.36	2.49
Year Ago EPS	0.8	0.48	2.23	2.33

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	3	3
Avg. Estimate	1.06B	860.65M	3.76B	3.99B
Low Estimate	1.02B	839.29M	3.64B	3.91B
High Estimate	1.1B	882M	3.83B	4.07B
Year Ago Sales	997M	938M	4.03B	3.76B
Sales Growth (year/est)	6.30%	-8.20%	-6.60%	6.10%

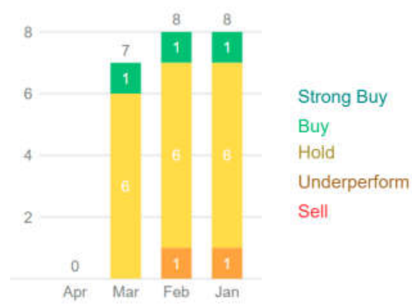
Earnings History	2017-03-30	2017-06-29	2017-09-29	2017-12-30
EPS Est.	0.76	0.49	0.39	0.62
EPS Actual	0.8	0.48	0.35	0.6
Difference	0.04	-0.01	-0.04	-0.02
Surprise %	5.30%	-2.00%	-10.30%	-3.20%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.76	0.5	2.33	2.43
7 Days Ago	0.75	0.5	2.33	2.43
30 Days Ago	0.76	0.5	2.33	2.43
60 Days Ago	0.79	0.5	2.35	2.43

People Also Watch

Symbol	Last Price	Change	% Change
FTS.TO FORTIS INC	43.49	-0.05	-0.11%
EMA.TO EMERA INCORPORATED	40.76	-0.15	-0.37%
ACO-X... ATCO LTD., CL.I, NV	41.38	-0.18	-0.43%
ENB.TO ENBRIDGE INC	40.52	+1.25	+3.18%
TA.TO TRANSALTA CORPORATION	6.98	+0.06	+0.87%

Recommendation Trends >



Recommendation Rating >

2.9

1 Strong Buy | 2 Buy | 3 Hold | 4 Under-perform | 5 Sell

Analyst Price Targets (6) >

Average 39.17

Low 36.00 High 42.00

Current 34.39

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EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	CU.TO	Industry	Sector	S&P 500
Current Qtr.	-5.00%	N/A	N/A	0.36
Next Qtr.	4.20%	N/A	N/A	0.37
Current Year	4.50%	N/A	N/A	0.20
Next Year	4.30%	N/A	N/A	0.11
Next 5 Years (per annum)	3.24%	N/A	N/A	0.12
Past 5 Years (per annum)	-0.78%	N/A	N/A	N/A

Emera Incorporated (EMA.TO)

Add to watchlist

Toronto - Toronto Delayed Price. Currency in CAD

Quote Lookup

40.76 -0.15 (-0.37%)

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Currency in CAD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	7	6	11	13
Avg. Estimate	0.82	0.61	2.75	2.88
Low Estimate	0.73	0.56	2.58	2.75
High Estimate	1.06	0.68	2.87	3.09
Year Ago EPS	0.72	0.55	2.46	2.75

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	1	1	5	7
Avg. Estimate	1.8B	1.71B	7.09B	7.01B
Low Estimate	1.8B	1.71B	6.48B	6.23B
High Estimate	1.8B	1.71B	7.98B	8.25B
Year Ago Sales	1.86B	1.47B	6.23B	7.09B
Sales Growth (year/est)	-2.80%	16.10%	13.90%	-1.00%

Earnings History	2017-03-30	2017-06-29	2017-09-29	2017-12-30
EPS Est.	0.72	0.51	0.72	0.61
EPS Actual	0.72	0.55	0.55	0.64
Difference	0	0.04	-0.17	0.03
Surprise %	0.00%	7.80%	-23.60%	4.90%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.82	0.61	2.75	2.88
7 Days Ago	0.82	0.61	2.74	2.88
30 Days Ago	0.82	0.61	2.74	2.88
60 Days Ago	0.78	0.66	2.85	2.99

Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	1	N/A

Growth Estimates	EMA.TO	Industry	Sector	S&P 500
Current Qtr.	13.90%	N/A	N/A	0.36
Next Qtr.	10.90%	N/A	N/A	0.37
Current Year	11.80%	N/A	N/A	0.20
Next Year	4.70%	N/A	N/A	0.11
Next 5 Years (per annum)	6.38%	N/A	N/A	0.12
Past 5 Years (per annum)	7.84%	N/A	N/A	N/A

Enbridge Inc. (ENB.TO)

Add to watchlist

Toronto - Toronto Delayed Price. Currency in CAD

Quote Lookup

40.52 +1.25 (+3.18%)

At close: March 29 4:17PM EDT

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Currency in CAD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	8	5	9	12
Avg. Estimate	0.69	0.58	2.32	2.53
Low Estimate	0.58	0.48	2.09	2.13
High Estimate	1.02	0.8	2.62	3
Year Ago EPS	0.57	0.4	1.96	2.32

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	4	3	7	8
Avg. Estimate	12.8B	11.69B	47.31B	48.17B
Low Estimate	12.11B	11.2B	40.47B	41.02B
High Estimate	13.6B	12.28B	52.22B	54.25B
Year Ago Sales	11.15B	11.12B	44.38B	47.31B
Sales Growth (year/est)	14.80%	5.20%	6.60%	1.80%

Earnings History	2017-03-30	2017-06-29	2017-09-29	2017-12-30
EPS Est.	0.62	0.45	0.43	0.56
EPS Actual	0.57	0.4	0.38	0.61
Difference	-0.05	-0.05	-0.05	0.05
Surprise %	-8.10%	-11.10%	-11.60%	8.90%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.69	0.58	2.32	2.53
7 Days Ago	0.68	0.57	2.33	2.54
30 Days Ago	0.62	0.53	2.31	2.51
60 Days Ago	0.63	0.53	2.33	2.52

Up Last 7 Days	1	N/A	1	1
Up Last 30 Days	2	N/A	1	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	1	1

Growth Estimates	ENB.TO	Industry	Sector	S&P 500
Current Qtr.	21.10%	N/A	N/A	0.36
Next Qtr.	45.00%	N/A	N/A	0.37
Current Year	18.40%	N/A	N/A	0.20
Next Year	9.10%	N/A	N/A	0.11
Next 5 Years (per annum)	6.44%	N/A	N/A	0.12
Past 5 Years (per annum)	3.56%	N/A	N/A	N/A

Valener Inc (VNR.TO)

Add to watchlist

Toronto - Toronto Delayed Price. Currency in CAD

Quote Lookup

20.22 -0.17 (-0.83%)

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Currency in CAD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	4	6	6
Avg. Estimate	0.86	0.04	1.31	1.38
Low Estimate	0.81	0.02	1.27	1.31
High Estimate	0.89	0.06	1.33	1.45
Year Ago EPS	0.85	0.06	1.37	1.31

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	0	0	1	1
Avg. Estimate	N/A	N/A	N/A	N/A
Low Estimate	N/A	N/A	N/A	N/A
High Estimate	N/A	N/A	N/A	N/A
Year Ago Sales	N/A	N/A	N/A	N/A
Sales Growth (year/est)	N/A	N/A	N/A	N/A

Earnings History	2017-03-30	2017-06-29	2017-09-29	2017-12-30
EPS Est.	0.88	0.02	-0.09	0.49
EPS Actual	0.85	0.06	-0.07	0.51
Difference	-0.03	0.04	0.02	0.02
Surprise %	-3.40%	200.00%	22.20%	4.10%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.86	0.04	1.31	1.38
7 Days Ago	0.86	0.04	1.31	1.38
30 Days Ago	0.86	0.04	1.31	1.38
60 Days Ago	0.88	0.04	1.38	1.38

Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	VNR.TO	Industry	Sector	S&P 500
Current Qtr.	1.20%	N/A	N/A	0.36
Next Qtr.	-33.30%	N/A	N/A	0.37
Current Year	-4.40%	N/A	N/A	0.20
Next Year	5.30%	N/A	N/A	0.11
Next 5 Years (per annum)	2.40%	N/A	N/A	0.12
Past 5 Years (per annum)	-14.81%	N/A	N/A	N/A

Treasury Spread Analysis

Dates	USGG10YR Index Last Price PX_LAST	USGG30YR Index Last Price PX_LAST	GCAN10YR Index Last Price PX_LAST	GCAN30YR Index Last Price PX_LAST
2018-02-19	2.8749	3.1316	2.318	2.464
2018-02-20	2.8896	3.153	2.323	2.463
2018-02-21	2.95	3.2204	2.353	2.491
2018-02-22	2.9207	3.2062	2.3	2.453
2018-02-23	2.866	3.1555	2.247	2.399
2018-02-26	2.8623	3.153	2.254	2.41
2018-02-27	2.8934	3.1588	2.275	2.434
2018-02-28	2.8606	3.1242	2.235	2.375
2018-03-01	2.8078	3.0834	2.177	2.33
2018-03-02	2.8643	3.1398	2.201	2.362
2018-03-05	2.8808	3.1531	2.194	2.373
2018-03-06	2.8863	3.1531	2.233	2.396
2018-03-07	2.8827	3.1498	2.238	2.413
2018-03-08	2.8571	3.1218	2.226	2.401
2018-03-09	2.8938	3.158	2.27	2.443
2018-03-12	2.8681	3.1292	2.239	2.413
2018-03-13	2.8426	3.0981	2.205	2.384
2018-03-14	2.817	3.0568	2.16	2.324
2018-03-15	2.828	3.0584	2.143	2.295
2018-03-16	2.8445	3.077	2.138	2.287
2018-03-19	2.8555	3.0859	2.169	2.305
2018-03-20	2.8959	3.1301	2.211	2.341
2018-03-21	2.883	3.1186	2.258	2.372
2018-03-22	2.8244	3.0624	2.177	2.299
2018-03-23	2.8135	3.0608	2.193	2.313
2018-03-26	2.852	3.0859	2.233	2.349
2018-03-27	2.7753	3.0286	2.145	2.285
2018-03-28	2.7807	3.0214	2.122	2.257
2018-03-29	2.7389	2.9737	2.091	2.228
2018-03-30	2.7389	2.9737	2.091	2.228

	30-Day Average
USGG10YR	2.85%
USGG30YR	3.11%
Spread	0.26%

	30-Day Average
GCAN10YR	2.21%
GCAN30YR	2.36%
Spread	0.15%

Duff and Phelps Cost of Capital

2017 Valuation Handbook

U.S. Guide to Cost of Capital

Market Results Through 2016

Duff & Phelps

WILEY

published as of the end of 2017 and 2018.[3.69] The choice in constructing the three-year average is an exercise in judgment.[3.70] We then adjusted the realized risk premiums from 1926 to the current year by removing this observed growth in price-to-earnings ratios, which has occurred primarily in the past 30 years.

William Goetzmann and Roger Ibbotson, commenting on the supply side approach of estimating expected risk premiums, note:

> *"These forecasts tend to give somewhat lower forecasts than historical risk premiums, primarily because part of the total returns of the stock market have come from price-earnings ratio expansion. This expansion is not predicted to continue indefinitely, and should logically be removed from the expected risk premium."*[3.71]

Chen estimated the ERP as of early 2011 relying on the supply side model exclusively.[3.72] To the authors of this book, this certainly indicates his preference of the supply side estimate to the straight historical average estimate.

Since this adjustment for the growth in price-to-earnings ratios reflects primarily changes observed during the past 30 years and the supply-side analysis (as we have implemented it) makes no other adjustments to the realized returns, one might interpret that a forward estimate of the long-term ERP derived from data in this *2017 Valuation Handbook – U.S. Guide to Cost of Capital* should be 5.97% (supply-side model on an arithmetic average basis) minus the 1.08% WWII Interest Rate Bias discussed earlier, or 4.89% for one-year holding period returns.

Unconditional ERP Estimates

The following summarizes the long-term unconditional ERP estimates as of 2016:

Exhibit 3.14: Long-term Realized Risk Premiums Measured Relative to Long-term U.S. Government Bonds

Adjusted Realized Risk Premium	Period	Arithmetic Average (%)	Geometric Average (%)
Long-term "Historical" ERP	1926–2016	6.94	4.81
Long-term "Supply-side" ERP	1926–2016	5.97	3.99
"Supply-side" minus WWII Interest Rate Bias ERP	1926–2016	4.89	n/a

Source of underlying data: Morningstar *Direct* database. Calculations by Duff & Phelps, LLC.

3.69 The geometric average supply-side ERP of 3.99% (see Exhibit 3.14) was converted into an (estimated) arithmetic average using the standard deviation of the annual returns of the S&P 500 total returns index, as measured over the period 1926–2016 (19.97%, see Exhibit 3.13), which resulted in a supply-side arithmetic average ERP of 5.97%. The extra return attributable to the price-to-earnings multiple expansion was 0.79% per annum, when calculating the supply side ERP based on the three-year averaging convention. The extra return due to the price-to-earnings multiple expansion through 2016 was 0.87% per annum using 1-year periods.

3.70 Magdalena Mroczek, "Unraveling the Supply-Side Equity Risk Premium," *The Value Examiner* (January/February 2012): 19–24.

3.71 William N.Goetzmann and Roger G.Ibbotson, "History and the Equity Risk Premium," Chapter 12 in *Handbook of the Equity Risk Premium*, ed. Rajnish Mehra (Amsterdam: Elsevier, 2008): 522–523.

3.72 Peng Chen, "Will Bonds Outperform Stocks over the Long Run? Not Likely," in *Rethinking the Equity Risk Premium*, ed. P. Brett Hammond, Jr., Martin L. Leibowitz, and Lawrence B. Siegel (The Research Foundation of CFA Institute, 2011): 117–129.

Duff and Phelps International Cost of Capital

2017 Valuation Handbook

International Guide to Cost of Capital

Market Results Through December 2016 and March 2017

Duff & Phelps

WILEY

Canada Long-Horizon Equity Risk Premia

in Local Currency (Canadian Dollar – CAD)
in Percent

	Start Date																					
End Date	1919	1920	1925	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980	1985	1990	1995	2000	2005	2010	2015	2016
1997	5.7	5.6	5.9	5.0	5.9	5.8	6.1	5.6	4.0	3.5	2.8	3.0	4.2	1.5	3.0	2.5	13.7					
1998	5.5	5.5	5.8	4.9	5.7	5.6	5.9	5.4	3.8	3.3	2.6	2.7	3.8	1.2	2.4	1.7	9.2					
1999	6.0	6.0	6.2	5.4	6.3	6.2	6.5	6.1	4.6	4.3	3.6	4.0	5.3	3.2	5.0	5.6	15.4					
2000	5.9	5.9	6.2	5.4	6.2	6.2	6.5	6.0	4.6	4.2	3.6	3.9	5.2	3.2	4.9	5.4	13.4	3.3				
2001	5.6	5.6	5.8	5.0	5.8	5.7	6.0	5.5	4.0	3.6	3.0	3.2	4.3	2.1	3.4	3.2	8.5	-8.8				
2002	5.3	5.3	5.5	4.7	5.4	5.3	5.6	5.0	3.5	3.1	2.4	2.5	3.4	1.1	2.1	1.4	5.0	-12.3				
2003	5.5	5.5	5.7	4.9	5.7	5.6	5.8	5.3	3.9	3.5	2.9	3.0	4.0	2.0	3.1	2.9	6.9	-3.8				
2004	5.6	5.5	5.7	5.0	5.7	5.7	5.9	5.4	4.0	3.6	3.0	3.2	4.2	2.3	3.4	3.3	7.1	-1.3				
2005	5.7	5.7	5.9	5.2	5.9	5.9	6.1	5.7	4.3	4.0	3.5	3.7	4.7	3.0	4.3	4.4	8.3	2.4	21.0			
2006	5.8	5.8	6.0	5.3	6.1	6.0	6.3	5.8	4.5	4.2	3.7	4.0	5.0	3.4	4.7	4.9	8.8	4.0	17.4			
2007	5.8	5.8	6.0	5.3	6.1	6.0	6.3	5.8	4.6	4.3	3.8	4.0	5.1	3.5	4.7	5.0	8.6	4.3	13.6			
2008	5.4	5.3	5.5	4.8	5.5	5.4	5.6	5.1	3.8	3.5	2.9	3.0	3.9	2.1	3.1	2.9	5.4	-0.1	1.4			
2009	5.6	5.6	5.8	5.1	5.8	5.8	6.0	5.5	4.3	4.0	3.5	3.7	4.6	3.1	4.1	4.2	7.1	2.9	7.1			
2010	5.7	5.7	5.9	5.2	5.9	5.8	6.1	5.6	4.4	4.1	3.6	3.9	4.8	3.3	4.4	4.6	7.3	3.6	7.7	11.1		
2011	5.5	5.5	5.7	5.0	5.6	5.6	5.8	5.3	4.1	3.8	3.3	3.5	4.3	2.8	3.8	3.7	6.1	2.2	4.7	-1.1		
2012	5.5	5.5	5.7	5.0	5.6	5.6	5.8	5.3	4.1	3.8	3.3	3.5	4.3	2.9	3.8	3.8	6.1	2.4	4.8	0.9		
2013	5.5	5.5	5.7	5.0	5.7	5.6	5.8	5.4	4.2	3.9	3.5	3.7	4.5	3.1	4.1	4.1	6.3	3.1	5.5	3.5		
2014	5.6	5.6	5.8	5.1	5.7	5.7	5.9	5.5	4.3	4.0	3.6	3.8	4.6	3.3	4.2	4.3	6.4	3.4	5.8	4.5		
2015	5.4	5.4	5.6	4.9	5.5	5.5	5.6	5.2	4.1	3.8	3.3	3.5	4.2	2.9	3.7	3.7	5.6	2.6	4.3	2.0	-10.4	
2016	5.6	5.5	5.7	5.1	5.7	5.6	5.8	5.4	4.3	4.0	3.6	3.8	4.6	3.3	4.2	4.3	6.3	3.5	5.6	4.5	4.4	19.3

Source of underlying data: 1.) Morningstar *Direct* database. Used with permission. All calculations performed by Duff & Phelps LLC.

Business Segment Analysis

ALLETE, Inc. Updated 3/30/2017, 2016 Form 10-K, page 36-41, 71-72, 137, 2015 Form 10-K, page 86

		Total	Regulated Operations Total	ALLETE clean Energy	US Water Services	Corporate and Other	Eliminations		Percent Regulated	Percent Electric T&D / Regulated
ALE										
	2016	1,339,700	1,000,700	80,500	137,500	121,000	-	ALE2016REV	75%	*98%*
Revenue	2015	1,486,400	991,200	262,100	119,800	113,300	-	ALE2015REV	67%	*98%*
	2014	1,136,800	1,003,500	33,200	-	100,100	-	ALE2014REV	88%	*97%*
	2016	223,500	172,900	27,300	4,600	23,800	(5,100)	ALE2016INC	77%	*97%*
Operating Income	2015	210,700	190,200	54,200	3,200	(33,700)	(3,200)	ALE2015INC	90%	*98%*
	2014	188,800	183,800	6,400	-	1,000	(2,400)	ALE2014INC	97%	*97%*
	2016	4,906,400	3,853,400	566,000	264,100	222,900	-	ALE2016ASSETS	79%	*99%*
Assets	2015	4,894,500	3,853,100	501,500	258,300	281,600	-	ALE2015ASSETS	79%	*99%*
	2014	4,360,800	3,709,600	291,900	-	359,300	-	ALE2014ASSETS	85%	*99%*

Alliant Energy Corporation — Updated 3/30/2017, 2016 Form 10-K, page 121-122

			Utility			Non-Regulated			
LNT		Total	Utility Electric Operations	Utility Gas Operations	Utility Other	Non-Regulated, Parent and Other		Percent Regulated	Percent Electric T&D / Regulated
	2016	3,320,000	2,875,500	355,400	48,600	40,500	LNT2016REV	99%	88%
Revenue	2015	3,253,600	2,770,500	381,200	57,900	44,000	LNT2015REV	99%	86%
	2014	3,350,300	2,713,600	517,500	66,100	53,100	LNT2014REV	98%	82%
	2016	537,000	571,900	30,700	(4,800)	(60,800)	LNT2016INC	111%	96%
Operating Income	2015	577,000	514,100	34,600	1,900	26,400	LNT2015INC	95%	93%
	2014	543,600	442,400	53,800	14,000	33,400	LNT2014INC	94%	87%
	2016	13,373,800	11,040,500	1,091,100	781,000	461,200	LNT2016ASSETS	97%	86%
Assets	2015	12,495,200	10,211,300	939,300	828,900	515,700	LNT2015ASSETS	96%	85%
	2014	12,063,500	9,660,400	913,500	993,900	495,700	LNT2014ASSETS	96%	84%

American Electric Power Company, Inc. Updated 3/30/2017, 2016 Form 10-K, pages 5-6, 219-221

AEP		Total	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other	**Reconciling Adjustments**		Percent Regulated	Percent Electric T&D / Regulated
	2016	16,380,100	9,091,900	4,422,400	512,800	-	2,986,000	105,100	(738,100)	AEP2016REV	86%	100%
Revenue	2015	16,453,200	9,172,200	4,556,600	329,200	-	3,412,700	99,000	(1,116,500)	AEP2015REV	85%	100%
	2014	16,378,600	9,484,400	4,813,600	191,900		3,849,600	95,400	(2,056,300)	AEP2014REV	88%	100%
	2016	1,391,500	1,888,100	909,300	453,600	-	(1,830,100)	(31,900)	2,500	AEP2016INC	234%	100%
Operating Income	2015	3,530,700	1,850,500	795,900	321,200	-	597,800	(22,700)	(12,000)	AEP2015INC	84%	100%
	2014	3,320,500	1,660,700	807,600	237,200		587,300	40,000	(12,300)	AEP2014INC	81%	100%
	2016	63,467,700	37,428,300	14,802,400	6,384,800	-	3,386,100	20,354,800	(18,888,700)	AEP2016ASSETS	92%	100%
Assets	2015	61,683,100	35,792,300	14,795,000	5,012,100	-	5,414,500	20,242,200	(19,573,000)	AEP2015ASSETS	90%	100%
	2014	59,544,600	33,705,100	14,524,600	3,570,000		6,326,200	20,512,900	(19,094,200)	AEP2014ASSETS	87%	100%

Duke Energy Corporation — Updated 3/31/2017, 2016 Form 10-K, pages 136-137 pages 42, 45, 47-48 and 129-130

DUK		Total	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Other	Eliminations		Percent Regulated	Percent Electric T&D / Regulated
	2016	22,743,000	21,366,000	901,000	484,000	117,000	(125,000)	DUK2016REV	98%	*96%*
Revenue	2015	22,371,000	21,521,000	541,000	286,000	135,000	(112,000)	DUK2015REV	99%	*98%*
	2014	22,621,000	21,691,000	578,000	236,000	116,000	-	DUK2014REV	98%	*97%*
	2016	5,341,000	5,545,000	264,000	(3,000)	(464,000)	(1,000)	DUK2016INC	109%	*95%*
Operating Income	2015	5,078,000	5,231,000	139,000	(35,000)	(256,000)	(1,000)	DUK2015INC	106%	*97%*
	2014	4,842,000	5,086,000	159,000	5,000	(406,000)	(2,000)	DUK2014INC	108%	*97%*
	2016	132,761,000	114,993,000	10,760,000	4,377,000	2,443,000	188,000	DUK2016ASSETS	95%	*91%*
Assets	2015	121,156,000	109,097,000	2,637,000	3,861,000	5,373,000	188,000	DUK2015ASSETS	92%	*98%*
	2014	120,557,000	104,119,000	2,512,000	2,981,000	10,755,000	190,000	DUK2014ASSETS	88%	*98%*

Edison International — Updated 3/31/2017, 2016 Form 10-K, pages 9, 38-49, 2014 assets 2015 10-K p. 42, 48

		Total	Electric Utility	Parent and Other		Percent Regulated	Percent Electric T&D / Regulated
EIX							
	2016	11,869,000	11,830,000	39,000	EIX2016REV	100%	*100%*
Revenue	2015	11,524,000	11,485,000	39,000	EIX2015REV	100%	*100%*
	2014	13,413,000	13,380,000	33,000	EIX2014REV	100%	*100%*
	2016	2,092,000	2,217,000	(125,000)	EIX2016INC	106%	*100%*
Operating Income	2015	2,008,000	2,080,000	(72,000)	EIX2015INC	104%	*100%*
	2014	2,472,000	2,529,000	(57,000)	EIX2014INC	102%	*100%*
	2016	51,319,000	50,891,000	428,000	EIX2016ASSETS	99%	*100%*
Assets	2015	50,229,000	49,795,000	434,000	EIX2015ASSETS	99%	*100%*
	2014	49,734,000	49,456,000	278,000	EIX2014ASSETS	99%	*100%*

Eversource Energy Updated 4/3/2017, 2016 Form 10-K, page 143

ES

		Total	Electric Distribution	Natural Gas Distribution	Electric Transmission	Other	Eliminations		Percent Regulated	Percent Electric T&D / Regulated
	2016	7,639,100	5,594,300	857,700	1,210,000	870,400	(893,300)	ES2016REV	100%	89%
Revenue	2015	7,954,800	5,903,600	995,500	1,069,100	863,600	(877,000)	ES2015REV	100%	88%
	2014	7,741,900	5,663,400	1,007,300	1,018,200	790,900	(737,900)	ES2014REV	99%	87%
	2016	1,859,900	934,500	163,500	702,400	58,800	700	ES2016INC	97%	91%
Operating Income	2015	1,764,200	1,008,200	148,300	588,600	16,700	2,400	ES2015INC	99%	92%
	2014	1,632,800	912,600	152,500	565,600	800	1,300	ES2014INC	100%	91%
	2016	32,053,200	18,367,500	3,303,800	8,751,500	14,493,100	(12,862,700)	ES2016ASSETS	95%	89%
Assets	2015	30,580,300	17,981,300	3,104,500	8,019,300	13,256,700	(11,781,500)	ES2015ASSETS	95%	89%
	2014	29,740,400	17,536,900	3,029,300	7,615,600	12,664,900	(11,106,300)	ES2014ASSETS	95%	89%

OGE Energy Corp.
Updated 3/31/2017, 2016 Form 10-K, pages 120-121

OGE ($ thousands)		Total	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations		Percent Regulated	Percent Electric T&D / Regulated
	2016	2,259,200	2,259,200	-	-	-	OGE2016REV	100%	100%
Revenue	2015	2,196,900	2,196,900	-	-	-	OGE2015REV	100%	100%
	2014	2,453,100	2,453,100	-	-	-	OGE2014REV	100%	100%
	2016	503,300	508,900	(7,700)	2,100		OGE2016INC	101%	100%
Operating Income	2015	481,200	500,400	(7,500)	(11,700)	-	OGE2015INC	104%	100%
	2014	536,800	538,000	(1,200)	-	-	OGE2014INC	100%	100%
	2016	9,939,600	8,669,400	1,521,600	89,000	(340,400)	OGE2016ASSETS	87%	100%
Assets	2015	9,580,600	8,525,500	1,439,500	174,600	(559,000)	OGE2015ASSETS	89%	100%
	2014	9,509,900	8,248,900	1,461,200	128,600	(328,800)	OGE2014ASSETS	87%	100%

Pinnacle West Capital Corporation
Updated 3/31/2017, 2016 Form 10-K, pages 82, 84

PNW	($ thousands)		Total	Regulated Electricity		Percent Regulated	Percent Electric T&D / Regulated
		2016	3,498,682	3,498,682	PNW2016REV	100%	100%
	Revenue	2015	3,495,443	3,495,443	PNW2015REV	100%	100%
		2014	3,491,632	3,491,632	PNW2014REV	100%	100%
		2016	855,984	855,984	PNW2016INC	100%	100%
	Operating Income	2015	854,602	854,602	PNW2015INC	100%	100%
		2014	811,242	811,242	PNW2014INC	100%	100%
		2016	16,004,253	16,004,253	PNW2016ASSETS	100%	100%
	Assets	2015	15,028,258	15,028,258	PNW2015ASSETS	100%	100%
		2014	14,288,890	14,288,890	PNW2014ASSETS	100%	100%

PNM Resources, Inc.
Updated 3/31/2017, 2016 Form 10-K, page B-38

PNM	($ thousands)		Total	PNM Electric	TNMP Electric	Corporate and Other		Percent Regulated	Percent Electric T&D / Regulated
		2016	1,362,951	1,035,913	327,038	-	PNM2016REV	100%	100%
	Revenue	2015	1,439,082	1,131,195	307,887	-	PNM2015REV	100%	100%
		2014	1,435,853	1,147,914	287,939	-	PNM2014REV	100%	100%
		2016	277,985	188,090	91,641	(1,746)	PNM2016INC	101%	100%
	Operating Income	2015	124,350	33,380	90,033	937	PNM2015INC	99%	100%
		2014	299,697	212,713	85,588	1,396	PNM2014INC	100%	100%
		2016	6,471,080	4,867,546	1,383,223	220,311	PNM2016ASSETS	97%	100%
	Assets	2015	6,009,328	4,599,344	1,297,139	112,845	PNM2015ASSETS	98%	100%
		2014	5,790,237	4,453,114	1,229,417	107,706	PNM2014ASSETS	98%	100%

Southern Company
Updated 3/31/2017, 2016 Form 10-K, pages II-146

SO	($ thousands)		Total	Traditional Operating Companies	Southern Power	Eliminations	Southern Company Gas	All Other	Eliminations		Percent Regulated	Percent Electric T&D / Regulated
		2016	19,896,000	16,803,000	1,577,000	(439,000)	1,652,000	463,000	(160,000)	SO2016REV	93%	91%
	Revenue	2015	17,699,000	16,491,000	1,390,000	(439,000)	-	152,000	105,000	SO2015REV	93%	100%
		2014	18,467,000	17,354,000	1,501,000	(449,000)	-	159,000	(98,000)	SO2014REV	94%	100%
		2016	4,637,000	4,325,000	253,000	-	209,000	(146,000)	(4,000)	SO2016INC	98%	95%
	Operating Income	2015	4,378,000	4,168,000	311,000	(1,000)	-	(100,000)	-	SO2015INC	95%	100%
		2014	3,756,000	3,540,000	257,000	-	-	(38,000)	(3,000)	SO2014INC	94%	100%
		2016	109,697,000	72,141,000	15,169,000	(316,000)	21,853,000	2,474,000	(1,624,000)	SO2016ASSETS	86%	77%
	Assets	2015	78,318,000	69,052,000	8,905,000	(397,000)	-	1,819,000	(1,061,000)	SO2015ASSETS	88%	100%
		2014	70,233,000	64,300,000	5,233,000	(131,000)	-	1,143,000	(312,000)	SO2014ASSETS	92%	100%

RRA Adjustment Clauses

S&P Global
Market Intelligence

September 12, 2017
spglobal.com/marketintelligence

RRA Regulatory Focus

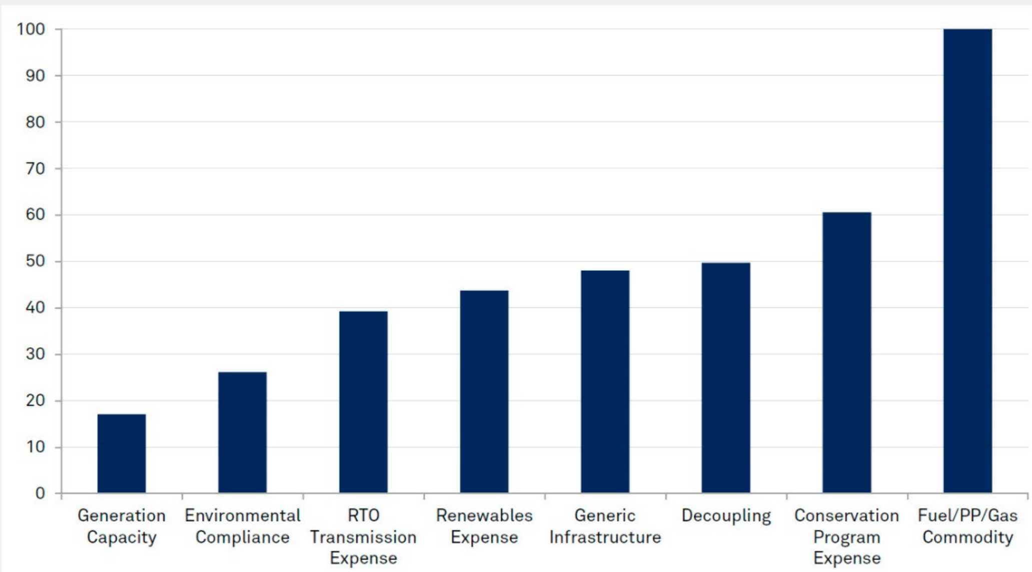
Adjustment Clauses

A state-by-state overview

In the face of the robust expansion of utility capital expenditures over the last 10 years or so — CapEx for the 53 companies in the RRA Index is estimated at $117.5 billion in 2017, versus $52 billion in 2006 — increases in various expenses and sluggish demand growth in most parts of the U.S., industry stakeholders have developed ever more innovative strategies to achieving timely rate recognition of these factors.

A key component of these strategies has been the implementation of adjustment clauses to address recovery of these expenditures, as well as issues related to rising/volatile costs and sluggish demand growth. These mechanisms have contributed to steady earnings growth in the sector. Earnings results for the first half of 2017 showed solid growth for utilities, with an average gain of 6.2% year-over-year. Despite overall mild weather in the first half of 2017, regional weather variations boosted sales for some utilities, while others saw returns from capital investments through rate increases.

Adjustment clauses in use (%)



As of Sept. 8, 2017.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

A defining characteristic of an adjustment clause is that it effectively shifts the risk associated with recovery of the expense in question from shareholders to customers, because if the clause operates as designed, the company is able to change its rates to recover its costs on a current basis, without any negative effect on the bottom line and without the expense and delay that accompanies a rate case filing.

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The electric and natural gas utilities' use of adjustment clauses to recover variations in certain costs outside of the traditional rate case process has its origins in the 1973 Arab oil embargo, when fuel costs skyrocketed, leaving the utilities with no way to recover the increased costs in a timely manner. At that time, the only remedy for the utilities was to file a rate case; however, rate proceedings frequently took more than a year to litigate, while fuel prices climbed more rapidly than the utilities could obtain rate recognition of the increased costs. Certain jurisdictions permitted the utilities to have more than one rate case pending simultaneously; however, most did not.

During these years, utility earnings were under considerable pressure, a situation that prompted certain jurisdictions to establish a more constructive framework to allow more timely recovery of cost increases that were beyond the control of the utilities.

The result was the creation of the fuel adjustment clause, or FAC, essentially a single-issue ratemaking process, whereby a utility is permitted to implement periodic rate adjustments to reflect changes in its cost of fuel. The utility is generally authorized to defer incremental variations in its fuel costs to offset any effect on earnings from the variation in the cost. The deferred amount is then recovered from, or refunded to, ratepayers in the next FAC rate adjustment. In some circumstances, the FAC includes a forward looking component that is subject to true up provisions. In addition to fuel costs, most jurisdictions allow the utilities' purchased power expense to be included in the FAC.

Over the ensuing years, the use of adjustment clauses has expanded greatly. Adjustment clauses are generally reserved for expenses that are outside the control of the utility or are required by law or rule. Some jurisdictions have approved the use of adjustment clauses for recovery of environmental compliance, energy efficiency and conservation program expenses, transmission charges allocated to the utility by the Federal Energy Regulatory Commission, and/or expenses related to meeting renewable resource requirements. Such mechanisms have also been approved to pass through to customers all or a portion of the margins that the company receives from selling excess power or pipeline capacity in the open market through off system sales.

Another type of adjustment clause, a decoupling mechanism, enables utilities to offset the effect on revenues of fluctuations in sales caused by customer participation in energy efficiency programs, deviations from "normal" temperature patterns, or economic conditions in their territories. 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.

More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation capacity or delivery infrastructure to be reflected in rates through an adjustment clause; effectively including these items in rate base without a full rate case. In some instances these mechanisms may even provide the utilities a cash return on construction work in progress.

This report covers the key adjustment clauses used by the largest electric and gas utilities in the 53 jurisdictions covered by RRA. This report does not address surcharges that have been approved to enable the utility to recover specific one-time items, e.g., excess storm restoration costs incurred in a given year, because under that scenario, the utility is recovering, over a defined period of time, a fixed amount that has already been incurred.

This report also does not include expense trackers, which provide for the deferral of variations in certain costs for potential recovery at a future time, when the commission will consider the net accumulated balance for inclusion in rates. Although an expense tracker is designed to keep the utility's earnings whole, rates and cash flows do not change on a current basis. Expense trackers are sometimes authorized to account for variations in pension-related costs. Although there are similarities between each of these types of ratemaking provisions, only adjustment clauses allow rates to change on an expedited basis in accordance with cost changes.

The accompanying table includes footnotes (denoted by "✓*" or "--*"), beginning on page 18, only where a clarification regarding the specific adjustment clause is necessary. Further details concerning the adjustment clauses included in this report can be found in each of RRA's Commission Profiles.

As indicated in the table, all of these jurisdictions employ some type of adjustment clause, with fuel/purchased power clauses being the most prevalent. All electric and gas utilities are permitted to adjust rates, outside of a base rate case, for variations in fuel/purchased power expenses. RRA notes that roughly two thirds of all utility commissions permit the use of, or are considering the use of, an adjustment clause for new capital investment. In addition, some form of decoupling is in place in the vast majority of the jurisdictions. Roughly one-third of all jurisdictions have adjustment clauses in place to reflect changes in the costs associated with the utilities' participation in regional transmission organizations.

Regulatory agency abbreviations

ACC	Arizona Corporation Commission
ARC	Alaska Regulatory Commission
BPU	Board of Public Utilities (New Jersey)
DPU	Department of Public Utilities (Massachusetts)
ICC	Illinois Commerce Commission
IUB	Iowa Utilities Board
KCC	Kansas Corporation Commission
NCUC	North Carolina Utilities Commission
NOCC	New Orleans City Council
OCC	Oklahoma Corporation Commission
PRC	Public Regulation Commission (New Mexico)
PSC	Public Service Commission
PUC	Public Utility(ies) Commission
PURA	Public Utilities Regulatory Authority (Connecticut)
RRC	Railroad Commission (Texas)
SCC	State Corporation Commission (Virginia)
URC	Utility Regulatory Commission (Indiana)
WUTC	Washington Utilities and Transportation Commission

Contributors: Jim Davis, Heike Doerr, Lillian Federico, Lisa Fontanella, Monica Hlinka, and Dennis Sperduto

Use of adjustment clauses (as of September 2017)

			Type of adjustment clause									
					Decoupling				New capital			
State/ Company	Ultimate parent ticker	Type of service	Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Full	Partial	Renewables expense	Environmental compliance	Generation capacity	Generic infrastructure	RTO-related transmission expense	Other
ALABAMA	-											
Alabama Power	SO	Elec.	✓ *	--	--	--	--	✓ *	✓ *	--	--	✓ *
Alabama Gas	SR	Gas	✓ *	--	--	✓ *	--	--	--	--	--	✓ *
Mobile Gas	SRE	Gas	✓ *	--	--	✓ *	--	--	--	--	--	✓ *
ALASKA												
Alaska Electric Light & Power	AVA	Elec.	✓	--	--	--	--	--	--	--	--	--
Enstar Natural Gas	--	Gas	✓	--	--	--	--	--	--	--	--	--
ARIZONA	-											
Arizona Public Service	PNW	Elec.	✓	✓	--	✓ *	✓	✓	✓ *	--	✓	✓ *
Southwest Gas	SWX	Gas	✓	✓	--	✓ *	--	--	--	✓	--	✓ *
Tucson Electric Power	--	Elec.	✓	✓	--	✓ *	✓	✓	--	--	--	✓ *
UNS Electric	--	Elec.	✓	✓	--	✓ *	✓	--	--	--	✓	✓ *
UNS Gas	--	Gas	✓	✓	--	✓ *	--	--	--	--	--	✓ *
ARKANSAS	-											
Arkansas Oklahoma Gas	--	Gas	✓	✓	✓	--	--	--	--	✓	--	✓ *
CenterPoint Energy Resources	CNP	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
Entergy Arkansas	ETR	Elec.	✓	✓	--	✓ *	--	--	✓ *	✓ *	✓	✓ *
Oklahoma Gas & Electric	OGE	Elec.	✓ *	✓	--	✓ *	✓	✓	✓	✓ *	✓	✓ *
Black Hills Energy Arkansas	BKH	Gas	✓	✓	✓	--	--	--	--	✓	--	✓ *
Southwestern Electric Power	AEP	Elec.	✓	✓	--	✓ *	--	✓	✓	--	--	✓ *
CALIFORNIA	-											
Pacific Gas & Electric	PCG	Elec.	✓	--	✓	--	--	--	--	--	--	--
Pacific Gas & Electric	PCG	Gas	✓	--	✓	--	--	--	--	--	--	--
San Diego Gas & Electric	SRE	Elec.	✓	--	✓	--	--	--	--	--	--	--

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
San Diego Gas & Electric	SRE	Gas	✓	--	✓	--	--	--	--	--	--	--
Southern California Edison	EIX	Elec.	✓	--	✓	--	--	--	--	--	--	--
Southern California Gas	SRE	Gas	✓	--	✓	--	--	--	--	--	--	--
Southwest Gas	SWX	Gas	✓	--	✓	--	--	--	--	--	--	--
COLORADO	-											
Black Hills Colorado Electric	BKH	Elec.	✓	✓	--	--	✓	-- *	✓ *	✓ *	--	✓ *
Public Service Co. of Colorado	XEL	Elec.	✓	✓	--	-- *	✓	✓ *	✓ *	✓ *	--	✓ *
Public Service Co. of Colorado	XEL	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	--
Black Hills Gas Distribution	BKH	Gas	✓	✓	--	--	--	--	--		--	--
CONNECTICUT												
Connecticut Lt. & Pwr.	ES	Elec.	-- *	✓	✓ *	--	--	--	--	--	✓	--
Conn. Natural Gas	--	Gas	✓	✓	✓ *	--	--	--	--	✓ *	--	--
Southern Conn. Gas	--	Gas	✓	✓	-- *	--	--	--	--	✓ *	--	--
United Illuminating	--	Elec.	-- *	✓	✓ *	--	--	--	--	--	✓	--
Yankee Gas Service	ES	Gas	✓	✓	-- *	--	--	--	--	✓ *	--	--
DELAWARE												
Chesapeake Utilities	CPK	Gas	✓	--	--	--	--	--	--	--	--	✓ *
Delmarva Power & Light	EXC	Elec.	-- *	--	--	--	--	--	--	--	✓	--
Delmarva Power & Light	EXC	Gas	✓	--	--	--	--	✓	--	--	--	--
DISTRICT OF COLUMBIA												
Potomac Electric Power	EXC	Elec.	-- *	--	--	✓ *	✓ *	--	--	✓ *	--	✓ *
Washington Gas Light	WGL	Gas	✓	--	--	--	--	--	--	✓ *	--	✓ *

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
FLORIDA												
Florida Power & Light	NEE	Elec.	✓	✓	--	--	--	✓		--	--	✓ *
Duke Energy Florida	DUK	Elec.	✓	✓	--	--	--	✓	✓ *	--	--	✓ *
Florida Public Utilities	CPK	Elec.	✓	✓	--	--	--	✓	✓ *	--	--	✓ *
Florida Public Utilities	CPK	Gas	✓	✓	--	--	--	✓	--	✓ *	--	✓ *
Gulf Power	SO	Elec.	✓	✓	--	--	--	✓	✓ *	--	--	✓ *
Peoples Gas System	--	Gas	✓	✓	--	--	--	✓	--	✓ *	--	✓ *
Pivotal Utility Holdings	SO	Gas	✓	✓	--	--	--	✓	--	✓ *	--	✓ *
Tampa Electric	--	Elec.	✓	✓	--	--	--	✓	✓ *	--	--	✓ *
GEORGIA												
Atlanta Gas Light	SO	Gas	-- *	--	-- *	--	--	✓ *	--	✓ *	--	--
Georgia Power	SO	Elec.	✓	--	--	--	--	--	✓ *	--	--	--
Liberty Utilities (Peach State Nat. Gas)	--	Gas	✓ *	--	✓ *	--	--	--	--	--	--	--
HAWAII												
Hawaiian Electric	HE	Elec.	✓	✓	✓	--	✓	--	✓ *	✓ *	--	✓ *
Hawaii Electric Light	HE	Elec.	✓	✓	✓	--	✓	--	✓ *	✓ *	--	✓ *
Maui Electric	HE	Elec.	✓	✓	✓	--	✓	--	✓ *	✓ *	--	✓ *
IDAHO												
Avista Corp.	AVA	Elec.	✓ *	✓	--	✓ *	--	--	--	--	--	--
Avista Corp.	AVA	Gas	✓	✓	--	✓ *	--	--	--	--	--	--
Idaho Power	IDA	Elec.	✓ *	✓	✓ *	--	--	--	--	--	--	--
PacifiCorp	BRK.A	Elec.	✓ *	✓	--	--	--	--	--	--	--	--
ILLINOIS												
Ameren Illinois	AEE	Elec.	-- *	✓	--	--	✓	✓ *	--	--	✓	✓ *
Ameren Illinois	AEE	Gas	✓	✓	✓	--	--	✓ *	--	✓ *	--	✓ *
Commonwealth Edison	EXC	Elec.	-- *	✓	--	--	✓	✓ *	--	✓ *	✓	✓ *
MidAmerican Energy	BRK.A	Elec.	✓	✓	--	--	✓	--	--	--	✓	✓ *
MidAmerican Energy	BRK.A	Gas	✓	✓	--	--	--	--	--	-- *	--	✓ *
North Shore Gas	WEC	Gas	✓	✓	✓	--	--	✓ *	--	✓ *	--	✓ *
Northern Illinois Gas	SO	Gas	✓	✓	--	--	--	✓ *	--	✓ *	--	✓ *
Peoples Gas Light & Coke	WEC	Gas	✓	✓	✓	--	--	✓ *	--	✓ *	--	✓ *

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
INDIANA												
Duke Energy Indiana	DUK	Elec.	✓	✓	--	✓ *	✓	✓ *	✓ *	✓ *	✓	✓ *
Indiana Gas	VVC	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
Indiana Michigan Power	AEP	Elec.	✓	✓	--	✓ *	✓	✓ *	--	✓ *	✓	✓ *
Indianapolis Power & Light	AES	Elec.	✓	✓	--	-- *	✓	✓ *	--	-- *	✓	✓ *
Northern Indiana Public Service	NI	Elec.	✓	✓	--	✓ *	✓	✓ *	--	✓ *	✓	✓ *
Northern Indiana Public Service	NI	Gas	✓	✓	--	--	--	--	--	✓ *	--	✓ *
Southern Indiana Gas & Electric	VVC	Elec.	✓	✓	--	✓ *	--	-- *	--	✓ *	✓	✓ *
Southern Indiana Gas & Electric	VVC	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
IOWA												
Black Hills Iowa Gas Utility	BKH	Gas	✓	✓	--	--	--	--	--	✓	--	✓ *
Interstate Power & Light	LNT	Elec.	✓	✓	--	--	✓	✓ *	--	--	✓	✓ *
Interstate Power & Light	LNT	Gas	✓	✓	--	--	--	--	--	--	--	✓ *
MidAmerican Energy	BRK.A	Elec.	✓	✓	--	--	✓	✓ *	--	--	✓	✓ *
MidAmerican Energy	BRK.A	Gas	✓	✓	--	--	--	--	--	--	--	✓ *
KANSAS												
Atmos Energy	ATO	Gas	✓	-- *	--	✓ *	--	--	--	✓ *	--	✓ *
Black Hills/Kansas Gas Utility	BKH	Gas	✓	-- *	--	✓ *	--	--	--	✓ *	--	✓ *
Empire District Electric	--	Elec.	✓	✓	--	--	--	✓	--	--	--	✓ *
Kansas City Power & Light	GXP	Elec.	✓	✓	--	--	--	--	--	✓ *	✓	✓ *
Kansas Gas & Electric	WR	Elec.	✓	✓	--	✓ *	✓	✓	--	--	✓	✓ *
Kansas Gas Service	OGS	Gas	✓	-- *	--	✓ *	--	--	--	✓ *	--	✓ *
Westar Energy	WR	Elec.	✓	✓	--	✓ *	✓	✓	--	--	✓	✓ *

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
KENTUCKY												
Atmos Energy	ATO	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	✓ *
Columbia Gas of Kentucky	NI	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	✓ *
Delta Natural Gas	DGAS	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	✓ *
Duke Energy Kentucky	DUK	Elec.	✓	✓	--	✓ *	✓	--	--	--	--	✓ *
Duke Energy Kentucky	DUK	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	✓ *
Kentucky Power	AEP	Elec.	✓	✓	--	✓ *	✓	✓ *	✓ *	--	--	✓ *
Kentucky Utilities	PPL	Elec.	✓	✓	--	✓ *	✓	✓ *	--	--	--	✓ *
Louisville Gas & Electric	PPL	Elec.	✓	✓	--	✓ *	✓	✓ *	--	--	--	✓ *
Louisville Gas & Electric	PPL	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	✓ *
LOUISIANA-NOCC												
Entergy New Orleans	ETR	Elec.	✓	✓	--	✓ *	--	✓ *	✓ *	--	✓	✓ *
Entergy New Orleans	ETR	Gas	✓	--	--	--	--	--	--	--	--	✓ *
LOUISIANA PSC												
Atmos Energy	ATO	Gas	✓	--	--	✓ *	--	--	--	✓ *	--	--
CenterPoint Energy Res. (Arkla)	CNP	Gas	✓	--	--	✓ *	--	--	--	--	--	--
Cleco Power	--	Elec.	✓	✓	--	✓ *	--	✓ *	✓ *	✓ *	✓ *	✓ *
Entergy Louisiana	ETR	Elec.	✓	✓	--	✓ *	--	✓ *	✓ *	--	✓ *	✓ *
Entergy Louisiana	ETR	Gas	✓	--	--	✓ *	--	--	--	✓ *	--	--
Southwestern Electric Power	AEP	Elec.	✓	✓	--	✓ *	--	✓ *	--	--	--	✓ *
MAINE												
Central Maine Power	--	Elec.	-- *	--	✓ *	--	--	--	--	--	--	✓ *
Emera Maine	--	Elec.	-- *	--	--	--	--	--	--	--	--	--
Maine Natural Gas	--	Gas	✓	--	--	--	--	--	--	--	--	--
Northern Utilities	UTL	Gas	✓	--	--	--	--	✓ *	--	✓ *	--	--
MARYLAND												
Baltimore Gas & Electric	EXC	Elec.	-- *	✓ *	✓	--	--	--	--	✓ *	--	✓ *
Baltimore Gas & Electric	EXC	Gas	✓	✓ *	✓	--	--	--	--	✓ *	--	✓ *

			Type of adjustment clause									
					Decoupling				New capital			
State/ Company	Ultimate parent ticker	Type of service	Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Full	Partial	Renewables expense	Environmental compliance	Generation capacity	Generic infrastructure	RTO-related transmission expense	Other
Columbia Gas of Maryland	NI	Gas	✓	✓ *	--	✓ *	--	--	--	✓ *	--	✓ *
Delmarva Power & Light	EXC	Elec.	-- *	✓ *	✓	--	--	--	--	✓ *	--	--
Potomac Edison	FE	Elec.	-- *	✓ *	--	--	--	--	--	--	--	✓ *
Potomac Electric Power	EXC	Elec.	-- *	✓ *	✓	--	--	--	--	✓ *	--	✓ *
Washington Gas Light	WGL	Gas	✓	✓ *	--	✓ *	--	--	--	✓ *	--	✓ *
MASSACHUSETTS												
Bay State Gas	NI	Gas	✓	✓ *	✓	--	--	✓ *	--	✓ *	--	✓ *
Berkshire Gas	--	Gas	✓	✓ *	--	--	--	✓ *	--	✓ *	--	--
Boston Gas/Colonial Gas	--	Gas	✓	✓ *	✓	--	--	✓ *	--	✓ *	--	✓ *
Fitchburg Gas & Electric	UTL	Elec.	-- *	✓ *	✓	--	--	--	--	✓ *	✓	✓ *
Fitchburg Gas & Electric	UTL	Gas	✓	✓ *	✓	--	--	✓ *	--	✓ *	--	✓ *
Liberty Utilities (New England Gas)	--	Gas	✓	✓ *	✓	--	--	✓ *	--	✓ *	--	✓ *
Massachusetts Electric	--	Elec.	-- *	✓ *	✓	--	✓ *	--	✓ *	✓ *	✓	✓ *
NSTAR Electric	ES	Elec.	-- *	✓ *	--	--	--	--	--	--	✓	✓ *
NSTAR Gas	ES	Gas	✓	✓ *	✓	--	--	✓ *	--	✓ *	--	✓ *
Western Mass. Electric	ES	Elec.	-- *	✓ *	✓	--	✓ *	--	✓ *	--	✓	✓ *
MICHIGAN												
Consumers Energy	CMS	Elec.	✓	✓	-- *	--	✓	--	--	--	✓ *	--
Consumers Energy	CMS	Gas	✓	✓	--	-- *	--	--	--	✓ *	--	--
DTE Electric	DTE	Elec.	✓	✓	-- *	--	✓	--	--	--	✓ *	--
DTE Gas	DTE	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	--
Indiana Michigan Power	AEP	Elec.	✓	✓	-- *	--	✓	--	--	--	--	--
Michigan Gas Utilities	WEC	Gas	✓	✓	--	-- *	--	--	--	--	--	--
SEMCO Energy Gas	--	Gas	✓	✓	--	--	--	--	--	--	--	--
Upper Peninsula Power	--	Elec.	✓	✓	-- *	--	✓	--	--	--	✓ *	--
Wisconsin Electric Power	WEC	Elec.	✓	✓	-- *	--	✓	--	--	--	--	--

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
MINNESOTA												
Minnesota Power	ALE	Elec.	✓	✓	--	--	✓	✓	--	--	✓	--
CenterPoint Energy Resources	CNP	Gas	✓	✓	✓ *	--	--	--	--	--	--	--
Minnesota Energy Resources	WEC	Gas	✓	✓	✓ *	--	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Elec.	✓	✓	✓ *	--	✓	✓	--	--	✓	--
Northern States Power-Minnesota	XEL	Gas	✓	✓	--	--	--	--	--	✓ *	--	--
Otter Tail Power	OTTR	Elec.	✓	✓	--	--	✓	✓	--	--	✓	--
MISSISSIPPI												
Atmos Energy	ATO	Gas	✓	✓	--	✓ *	--	--	--	--	--	--
Entergy Mississippi	ETR	Elec.	✓	✓	--	✓ *	--	✓ *	--	--	✓	✓ *
Mississippi Power	SO	Elec.	✓	✓	--	✓ *	--	✓ *	--	--	--	✓ *
MISSOURI												
Empire District Electric	--	Elec.	✓	--	--	--	-- *	✓ *	--	--	✓ *	✓ *
Empire District Gas	--	Gas	✓	--	--	-- *	--	--	--	--	--	✓ *
Kansas City Power & Light	GXP	Elec.	✓	✓ *	--	✓ *	-- *	-- *	--	✓ *	✓ *	✓ *
KCP&L Greater Missouri Operations	GXP	Elec.	✓	✓ *	--	✓ *	✓ *	✓ *	--	✓ *	✓ *	✓ *
Laclede Gas	SR	Gas	✓	--	--	-- *	--	--	--	✓ *	--	✓ *
Liberty Utilities (Midstates Natural Gas)	--	Gas	✓	--	--	-- *	--	--	--	✓ *	--	✓ *
Missouri Gas Energy	SR	Gas	✓	--	--	-- *	--	--	--	✓ *	--	✓ *
Union Electric	AEE	Elec.	✓	✓ *	--	✓ *	-- *	✓ *	--	✓ *	✓ *	✓ *
Union Electric	AEE	Gas	✓	--	--	-- *	--	--	--	✓ *	--	✓ *
MONTANA												
MDU Resources	MDU	Elec.	✓ *	✓	--	--	--	--	--	--	--	✓ *
MDU Resources	MDU	Gas	✓	✓	--	✓ *	--	--	--	--	--	--
NorthWestern Corp.	NWE	Elec.	✓ *	✓	--	--	--	--	--	--	--	✓ *
NorthWestern Corp.	NWE	Gas	✓	✓	--	--	--	--	--	--	--	✓ *

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
NEBRASKA												
Black Hills Nebraska Gas Utility	BKH	Gas	✓	--	--	--	--	--	--	✓ *	--	✓ *
Northwestern Energy	NWE	Gas	✓	--	--	--	--	--	--	-- *	--	✓ *
Black Hills Gas Distribution	BKH	Gas	✓	--	--	--	--	--	--	✓ *	--	✓ *
NEVADA												
Nevada Power	BRK.A	Elec.	✓	✓	--	✓ *	--	--	--	--	--	--
Sierra Pacific Power	BRK.A	Elec.	✓	✓	--	✓ *	--	--	--	--	--	--
Sierra Pacific Power	BRK.A	Gas	✓	--	--	--	--	--	--	-- *	--	--
Southwest Gas	SWX	Gas	✓	--	✓ *	--	--	--	--	✓ *	--	✓ *
NEW HAMPSHIRE												
Liberty Util. (EnergyNorth Natural Gas)	--	Gas	✓	--	--	-- *	--	--	--	✓ *	--	--
Liberty Util. (Granite State Electric)	--	Elec.	-- *	--	--	-- *	--	--	--	✓ *	--	--
Northern Utilities	UTL	Gas	✓	--	--	-- *	--	--	--	--	--	--
Public Service Co. of New Hampshire	ES	Elec.	✓ *	--	--	-- *	--	--	--	✓ *	✓	--
Unitil Energy Systems	UTL	Elec.	-- *	--	--	-- *	--	--	--	✓ *	--	--
NEW JERSEY												
Atlantic City Electric	EXC	Elec.	-- *	✓ *	--	--	✓	✓ *	--	-- *	--	✓ *
Jersey Central Power & Light	FE	Elec.	-- *	✓ *	--	--	✓	✓ *	--	-- *	--	✓ *
New Jersey Natural Gas	NJR	Gas	✓	✓ *	✓ *	--	--	✓ *	--	✓ *	--	✓ *
Pivotal Utility Holdings	SO	Gas	✓	✓ *	--	✓ *	--	✓ *	--	✓ *	--	✓ *
Public Service Electric & Gas	PEG	Elec.	-- *	✓ *	--	--	✓	✓ *	--	✓ *	--	✓ *
Public Service Electric & Gas	PEG	Gas	✓	✓ *	--	✓ *	--	✓ *	--	✓ *	--	✓ *
Rockland Electric	ED	Elec.	-- *	✓ *	--	--	✓	-- *	--	✓ *	--	✓ *
South Jersey Gas	SJI	Gas	✓	✓ *	✓ *	--	--	✓ *	--	✓ *	--	✓ *

			Type of adjustment clause									
					Decoupling				New capital			
State/ Company	Ultimate parent ticker	Type of service	Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Full	Partial	Renewables expense	Environmental compliance	Generation capacity	Generic infrastructure	RTO-related transmission expense	Other
NEW MEXICO												
El Paso Electric	EE	Elec.	✓	✓	--	--	--	--	--	--	--	✓ *
New Mexico Gas	--	Gas	✓	✓	--	--	--	--	--	--	--	✓ *
Public Service Co. of New Mexico	PNM	Elec.	✓	✓	--	--	✓	✓ *	--	✓ *	--	✓ *
Southwestern Public Service	XEL	Elec.	✓	✓	--	--	✓	--	--	--	--	✓ *
NEW YORK												
Brooklyn Union Gas	--	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
Central Hudson Gas & Electric	--	Elec.	-- *	--	✓	--	✓	--	--	--	--	--
Central Hudson Gas & Electric	--	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
Consolidated Edison of New York	ED	Elec.	-- *	--	✓	--	✓	--	--	--	--	--
Consolidated Edison of New York	ED	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
KeySpan Gas East	--	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
National Fuel Gas Distribution	NFG	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
New York State Electric & Gas	--	Elec.	-- *	--	✓	--	✓	--	--	--	--	--
New York State Electric & Gas	--	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
Niagara Mohawk Power	--	Elec.	-- *	--	✓	--	✓	--	--	--	--	--
Niagara Mohawk Power	--	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
Orange & Rockland Utilities	ED	Elec.	-- *	--	✓	--	✓	--	--	--	--	--
Orange & Rockland Utilities	ED	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
Rochester Gas & Electric	--	Elec.	-- *	--	✓	--	✓	--	--	--	--	--
Rochester Gas & Electric	--	Gas	✓	--	✓	--	--	--	--	✓ *	--	--

State/ Company	Ultimate parent ticker	Type of service	Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
			Type of adjustment clause									
NORTH CAROLINA												
Duke Energy Carolinas	DUK	Elec.	✓	✓ *	--	-- *	✓ *	✓ *	--	--	--	--
Duke Energy Progress	DUK	Elec.	✓	✓ *	--	-- *	✓ *	✓ *	--	--	--	--
Piedmont Natural Gas	PNY	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
Public Service Co. of North Carolina	SCG	Gas	✓	--	✓	--	--	--	--	✓ *	--	--
Virginia Electric & Power	D	Elec.	✓	✓ *	--	-- *	✓ *	✓ *	--	--	--	--
NORTH DAKOTA												
MDU Resources	MDU	Elec.	✓	--	--	--	✓ *	✓ *	✓ *	✓ *	--	--
MDU Resources	MDU	Gas	✓	--	--	✓ *	--	--	--	--	--	--
Northern States Power-Minnesota	XEL	Elec.	✓	--	--	--	✓	-- *	--	✓ *	--	✓ *
Northern States Power-Minnesota	XEL	Gas	✓	--	-- *	--	--	--	--	--	--	--
Otter Tail Power	OTTR	Elec.	✓	--	--	--	✓	✓ *	--	✓ *	--	✓ *
OHIO												
Cleve. Elec. Illum./Ohio Ed./Toledo Ed.	FE	Elec.	-- *	✓ *	--	✓ *	✓	--	--	✓ *	✓	✓ *
Columbia Gas of Ohio	NI	Gas	-- *	✓	-- *	--	--	--	--	✓ *	--	✓ *
Dayton Power & Light	AES	Elec.	-- *	✓ *	--	✓ *	✓	--	--	--	✓	✓ *
Duke Energy Ohio	DUK	Elec.	-- *	✓ *	--	✓ *	✓	--	--	✓ *	✓	✓ *
Duke Energy Ohio	DUK	Gas	✓	--	-- *	--	--	✓ *	--	✓ *	--	✓ *
East Ohio Gas	D	Gas	-- *	✓	-- *	--	--	--	--	✓ *	--	✓ *
Ohio Power	AEP	Elec.	-- *	✓ *	--	✓ *	✓	--	--	✓ *	✓	✓ *
Vectren Energy Delivery of Ohio	VVC	Gas	-- *	✓	-- *	--	--	--	--	✓ *	--	✓ *
OKLAHOMA												
CenterPoint Energy Resources	CNP	Gas	✓	✓ *	--	✓ *	--	--	--	--	--	✓ *
Oklahoma Gas & Electric	OGE	Elec.	✓	✓ *	--	✓ *	✓	✓ *	--	✓ *	✓	✓ *
Oklahoma Natural Gas	OGS	Gas	✓	✓ *	--	✓ *	--	--	--	--	--	✓ *
Public Service Oklahoma	AEP	Elec.	✓	✓ *	--	✓ *	--	✓ *	--	✓ *	✓	✓ *

State/ Company	Ultimate parent ticker	Type of service	Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
							Type of adjustment clause					
OREGON												
Avista Corp.	AVA	Gas	✓	✓	✓ *		--	--	--	--	--	--
Cascade Natural Gas	MDU	Gas	✓	✓	--	✓ *	--	✓ *	--	--	--	--
Idaho Power	IDA	Elec.	✓	✓	--	--	✓	--	--	--	--	--
Northwest Natural Gas	NWN	Gas	✓	--	--	✓ *	--	✓ *	--	--	--	--
PacifiCorp	BRK.A	Elec.	✓	✓	--	--	✓	--	--	--	--	--
Portland General Electric	POR	Elec.	✓	✓	--	✓ *	✓	--	--	--	--	--
PENNSYLVANIA												
Columbia Gas of Pennsylvania	NI	Gas	✓ *	--	-- *	✓ *	--	--	--	✓ *	--	✓ *
Duquesne Light	--	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	✓	✓ *
Equitable Gas	--	Gas	✓ *	--	-- *	--	--	--	--	✓ *	--	✓ *
Metropolitan Edison	FE	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	✓	✓ *
National Fuel Gas Distribution	NFG	Gas	✓ *	--	-- *	--	--	--	--	-- *	--	✓ *
PECO Energy	EXC	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	--	✓ *
PECO Energy	EXC	Gas	✓ *	✓	-- *	--	--	--	--	✓ *	--	✓ *
Pennsylvania Electric	FE	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	✓	✓ *
Pennsylvania Power	FE	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	--	✓ *
Peoples Natural Gas	--	Gas	✓ *	--	-- *	--	--	--	--	✓ *	--	✓ *
PPL Electric Utilities	PPL	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	✓	✓ *
UGI Central Penn Gas	UGI	Gas	✓ *	--	-- *	--	--	--	--	✓ *	--	✓ *
UGI Penn Natural Gas	UGI	Gas	✓ *	-- *	-- *	--	--	--	--	✓ *	--	✓ *
UGI Utilities	UGI	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	--	✓ *
UGI Utilities	UGI	Gas	✓ *	✓	-- *	--	--	--	--	✓ *	--	✓ *
West Penn Power	FE	Elec.	-- *	✓	-- *	--	-- *	--	--	✓ *	--	✓ *
RHODE ISLAND												
Narragansett Electric	--	Elec.	-- *	--	✓	--	--	--	--	✓ *	--	✓ *
Narragansett Electric	--	Gas	✓	✓	✓	--	--	✓	--	✓ *	--	✓ *
SOUTH CAROLINA												
Duke Energy Progress	DUK	Elec.	✓	--	--	--	--	✓ *	-- *	--	--	--
Duke Energy Carolinas	DUK	Elec.	✓	--	--	--	--	✓ *	-- *	--	--	--

State/ Company	Ultimate parent ticker	Type of service	Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
												Type of adjustment clause
Piedmont Natural Gas	PNY	Gas	✓	--	--	✓ *	--	--	--	--	--	--
South Carolina Electric & Gas	SCG	Elec.	✓	--	--	--	--	✓ *	✓ *	--	--	--
South Carolina Electric & Gas	SCG	Gas	✓	--	--	✓ *	--	--	--	--	--	--
SOUTH DAKOTA												
Black Hills Power	BKH	Elec.	✓	✓ *	--	✓ *	--	✓	--	--	✓	✓ *
Northern States Power-Minnesota	XEL	Elec.	✓	✓ *	--	✓ *	--	✓	✓ *	✓ *	--	✓ *
NorthWestern Corp.	NWE	Elec.	✓	✓	--	--	--	--	--	--	--	--
TENNESSEE												
Atmos Energy	ATO	Gas	✓	--	--	✓ *	--	--	--	--	--	✓ *
Chattanooga Gas	SO	Gas	✓	--	✓ *	--	--	--	--	--	--	✓ *
Kingsport Power	AEP	Elec.	✓	--	--	--	--	--	--	--	--	--
Piedmont Natural Gas	PNY	Gas	✓	--	--	✓ *	--	--	--	✓	--	✓ *
TEXAS PUC												
AEP Texas Central	AEP	Elec.	✓ *	✓	--	--	--	--	--	✓ *	✓ *	--
AEP Texas North	AEP	Elec.	✓ *	✓	--	--	--	--	--	✓ *	✓ *	--
CenterPoint Energy Houston Electric	CNP	Elec.	-- *	✓	--	--	--	--	--	✓ *	✓ *	✓ *
Cross Texas Transmission	--	Elec.	--	--	--	--	--	--	--	✓ *	✓	--
El Paso Electric	EE	Elec.	✓ *	✓	--	--	--	--	--	✓ *	--	✓ *
Electric Transmission of Texas	BRK.A/AEP	Elec.	--	--	--	--	--	--	--	✓ *	✓	--
Entergy Texas	ETR	Elec.	✓ *	✓	--	--	--	--	--	✓ *	✓	✓ *
Lone Star Transmission	NEE	Elec.	--	--	--	--	--	--	--	✓ *	--	--
Oncor Electric Delivery	--	Elec.	✓ *	✓	--	--	--	--	--	✓ *	✓ *	--
Sharyland Utilities	--	Elec.	-- --	--	--	--	--	--	--	✓ *	✓	✓
Southwestern Electric Power	AEP	Elec.	✓ *	✓	--	--	--	--	--	✓ *	✓	--
Southwestern Public Service	XEL	Elec.	✓ *	✓	--	--	--	--	--	✓ *	✓	✓ *
Texas-New Mexico Power	PNM	Elec.	✓ *	✓	--	--	--	--	--	✓ *	✓ *	✓ *
Wind Energy Transmission of Texas	--	Elec.	--	--	--	--	--	--	--	✓ *	--	--

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
TEXAS RRC												
Atmos Energy	ATO	Gas	✓ *	--	--	✓ *	--	--	--	✓ *	--	✓ *
CenterPoint Energy Resources	CNP	Gas	✓ *	--	--	--	--	--	--	✓ *	--	--
Texas Gas Service	OGS	Gas	✓ *	--	--	✓ *	--	--	--	✓ *	--	--
UTAH												
PacifiCorp	BRK.A	Elec.	✓	✓	--	--	✓ *	--	--	--	--	--
Questar	STR	Gas	✓	✓	✓ *	--	--	--	--	✓ *	--	✓ *
VERMONT												
Green Mountain Power	--	Elec.	✓	--	-- *	--	--	--	--	--	--	--
VIRGINIA												
Appalachian Power	AEP	Elec.	✓ *	✓	--	--	✓	-- *	✓ *	-- *	✓	✓ *
Columbia Gas of Virginia	NI	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--	✓ *
Kentucky Utilities	PPL	Elec.	✓ *	--	--	--	--	--	-- *	-- *	--	--
Virginia Electric & Power	D	Elec.	✓ *	✓	--	--	✓	✓ *	✓ *	-- *	✓	✓ *
Virginia Natural Gas	SO	Gas	✓	--	--	✓ *	--	--	--	✓ *	--	--
Washington Gas Light	WGL	Gas	✓	--	--	✓ *	--	--	--	✓ *	--	✓ *
WASHINGTON												
Avista Corp.	AVA	Elec.	✓ *		✓ *	--	--	--	--	--	--	--
Avista Corp.	AVA	Gas	✓	--	✓ *	--	--	--	--	-- *	--	--
Cascade Natural Gas	MDU	Gas	✓	--	✓ *	--	--	--	--	✓ *	--	--
Northwest Natural Gas	NWN	Gas	✓	✓	--	--	--	--	--	-- *	--	--
PacifiCorp	BRK.A	Elec.	✓ *	--	✓ *	--	--	--	--	--	--	--
Puget Sound Energy	--	Elec.	✓ *	--	--	✓ *	--	--	--	--	--	--
Puget Sound Energy	--	Gas	✓	--	--	✓ *	--	--	--	✓ *	--	--
WEST VIRGINIA												
Appalachian Power/Wheeling Power	AEP	Elec.	✓	✓	--	--	✓	-- *	-- *	✓ *	--	✓ *

			Type of adjustment clause									
					Decoupling				New capital			
State/ Company	Ultimate parent ticker	Type of service	Electric fuel/ gas commodity/ purch. power	Conserv. program expense	Full	Partial	Renewables expense	Environmental compliance	Generation capacity	Generic infrastructure	RTO-related transmission expense	Other
Hope Gas	D	Gas	✓	--	--	--	--	--	--	✓ *	--	✓ *
Monongahela Power	FE	Elec.	✓	✓	--	--	--	--	--	✓ *	--	✓ *
Mountaineer Gas	--	Gas	✓	--	--	--	--	--	--	✓ *	--	✓ *
Potomac Edison	FE	Elec.	✓	✓	--	--	--	--	--	✓ *	--	✓ *
WISCONSIN												
Madison Gas & Electric	MGEE	Elec.	✓ *	--	--	--	--	--	-- *	-- *	--	✓ *
Madison Gas & Electric	MGEE	Gas	✓	--	--	--	--	--	-- *	-- *	--	✓ *
Northern States Power-Wisconsin	XEL	Elec.	✓ *	--	--	--	--	--	-- *	-- *	--	✓ *
Northern States Power-Wisconsin	XEL	Gas	✓	--	--	--	--	--	-- *	-- *	--	✓ *
Wisconsin Electric Power	WEC	Elec.	✓ *	--	--	--	--	--	-- *	-- *	--	✓ *
Wisconsin Electric Power	WEC	Gas	✓	--	--	--	--	--	-- *	-- *	--	✓ *
Wisconsin Gas	WEC	Gas	✓	--	--	--	--	--	-- *	-- *	--	✓ *
Wisconsin Power & Light	LNT	Elec.	✓ *	--	--	--	--	--	-- *	-- *	--	✓ *
Wisconsin Power & Light	LNT	Gas	✓	--	--	--	--	--	-- *	-- *	--	✓ *
Wisconsin Public Service	WEC	Elec.	✓ *	--	--	--	--	--	-- *	-- *	--	✓ *
Wisconsin Public Service	WEC	Gas	✓	--	--	--	--	--	-- *	-- *	--	✓ *
WYOMING												
Cheyenne Light Fuel & Power	BKH	Elec.	✓	✓	--	✓ *	✓ *	--	--	--	--	✓ *
Cheyenne Light Fuel & Power	BKH	Gas	✓	✓	--	✓ *	--	--	--	--	--	--
MDU Resources	MDU	Elec.	✓	--	--	--	✓ *	--	--	--	--	--
PacifiCorp	BRK.A	Elec.	✓	✓	--	--	✓ *	✓ *	--	--	--	--
Black Hills Gas Distribution	BKH	Gas	✓	--	--	✓ *	--	--	--	--	--	--

Key:
✓ Adjustment clause exists for the company/state/operation.
* See text for further information.
As of: Sep. 12, 2017.

FOOTNOTES

Alabama

Electric Fuel/Gas Commodity/Purchased Power—The Certificated New Plant, or Rate CNP, adjustment clause for Alabama Power provides for recovery of the costs, excluding fuel, associated with certified purchased power agreements. Adjustments under the clause are subject to a staff and Alabama PSC review process that includes public hearings. Alabama Gas and Mobile Gas utilize a Competitive Fuel Clause that allows the companies to immediately adjust prices in order to compete with any alternate fuel or gas supply source, with no loss of earnings margin for the companies.

Decoupling—Alabama Gas and Mobile Gas use weather normalization clauses.

Environmental Compliance/Generation Capacity—The Rate CNP adjustment clause used by Alabama Power provides for recovery of costs related to: the commercial operation of certified generating facilities; certified purchased power agreements; and environmental mandates. Recoverable environmental costs include: applicable operation and maintenance expenses; depreciation and a return on capital beginning with 2005 investments; and, a true-up of prior period over/under-recovered amounts. Such costs are generally subject to PSC review, but not a full evidentiary hearing.

Other—The tariffs of the major energy utilities include adjustment provisions to reflect changes in income taxes, and certain general and local taxes.

Arizona

Decoupling—A partial decoupling mechanism, called the delivery charge adjustment, is in place for Southwest Gas. The mechanism excludes the effects of weather.

Arizona Public Service, or APS, utilizes a Lost Fixed Cost Recovery, or LFCR, mechanism designed to make the company whole for contributions to fixed-cost-recovery that are lost due to customer participation in energy efficiency and distributed energy, such as rooftop solar, programs. The LFCR is capped at 1% of annual revenues, with any excess being deferred with interest to be recovered through a future annual adjustment.

UNS Gas is subject to an incentive-based LFCR plan that allows the company to attain greater amounts of fixed-cost recovery as it meets its commission-defined energy efficiency goals. Residential customers are permitted to opt out of the LFCR provisions if they agree to a rate structure that incorporates a higher basic service fixed monthly charge. The LFCR is capped at 1% of annual revenues, with any excess being deferred with interest to be recovered through a future annual adjustment.

Tucson Electric Power, or TEP, operates under an LFCR mechanism designed to mitigate the revenue impact of lost sales associated with the ACC's energy efficiency standards and the distributed generation requirements under the commission's renewable energy standards. The annual adjustments are to be capped at 2% of retail revenues, with any amount in excess of 2% to be deferred for future recovery. The LFCR mechanism also includes a provision through which TEP recovers lost revenues associated with "reliability must-run generation."

UNS Electric also utilizes an LFCR mechanism, under which the company is permitted to implement annual rate adjustments related to any shortfall in recovery of fixed costs due to energy efficiency and distributed generation. The LFCR is not intended to recover fixed costs due to other factors, such as weather or general economic conditions, and, as such, is not considered a full decoupling mechanism. The annual adjustments are to be capped at 1%, with any amount in excess of 1% to be deferred for future recovery.

Generation Capacity—A rider is in place to address the costs associated with APS' acquisition of a 48% share of the coal-fired Four Corners Units 4 and 5 and certain related facilities, and the retirement of Four Corners Units 1, 2 and 3, which are wholly owned by APS.

Generic Infrastructure—A mechanism is in place through which Southwest Gas recovers the costs associated with a program under which the company is replacing distribution pre-1970 vintage steel pipelines.

Other—All of the utilities recover franchise fees on a current basis through an adjustable line item on the monthly bill. An economic development rider is in place for certain large-use customers of TEP and UNS Electric. Southwest Gas has a mechanism in place that provides for the recovery of costs associated with replacing customer-owned facilities with equipment that is owned and operated by the utility.

Arkansas

Electric Fuel/Gas Commodity/Purchased Power—Oklahoma Gas and Electric's, or OG&E's, energy cost recovery rider provides for the flow-through to ratepayers of 100% of the Arkansas-jurisdictional proceeds from the sale of excess SO_2 emissions allowances, as well as a share of the value of "green credits" resulting from the monetized environmental benefits of generation at the company's Centennial Wind Farm equal to the portion of the project dedicated to serving the Arkansas jurisdiction.

Decoupling—A generic framework, effectively a partial decoupling mechanism, is in place that provides for the electric and gas utilities to recover the lost contribution to fixed costs associated with energy efficiency, or EE,-related usage reductions and to retain a portion of the net benefits related to EE programs. The gas utilities have been using full decoupling mechanisms for several years.

Generation Capacity—Entergy Arkansas, or EA, utilizes a capacity acquisition rider to recover costs associated with its investment in certain generation facilities, and a capacity cost recovery rider to flow through the net costs related to the company's purchases of capacity to serve retail customers.

Generic Infrastructure—EA uses a rider to recover costs associated with certain government-mandated investments. EA, OG&E and CenterPoint Energy Resources, or CER, are subject to a formula rate plan framework to address annual changes in their cost of service.

Other—EA uses a storm recovery charges rider to collect from ratepayers the amounts required to service its related securitization bonds. OG&E uses a "Smart Grid" rider. Arkansas Oklahoma Gas, CER, EA, OG&E, Black Hills Energy Arkansas and Southwestern Electric Power have a mechanism in place to recover variations in certain taxes and franchise fees.

Colorado

Decoupling—An adjustment clause is in place for Public Service Company of Colorado's, or PSCO's, gas operations that includes a provision that provides for recovery of lost revenues associated with customer participation in demand-side management programs.

For PSCO's electric operations, the PUC approved a pilot partial decoupling mechanism for the company's residential and small commercial customers on July 11, 2017. The mechanism is not yet in place, but is expected to be implemented in 2018 coincident with new rates stemming from a yet to be filed rate case. Annual adjustments under the mechanism are to be capped at 3% of class revenues.

Environmental Compliance—A rider is in place for PSCO that provides for a cash return on construction work in progress, or CWIP, and reflects in rates costs associated with the installation of environmental controls at the coal-fired Pawnee and Hayden facilities.

Generation Capacity—Black Hills Colorado Electric Utility, or BHCE, has a rider in place that reflects the company's investment in the gas fired LM6000 plant at the Pueblo Generating Station. The rider was not rolled into base rates in the company's last rate case and is accorded a lower ROE than that established for BHCE's other Colorado jurisdictional operations. The rider is to remain in place until BHCE's nest rate case. A similar rider is in place for PSCO that reflects the company's investment in the Cherokee natural gas combined cycle plants.

Generic Infrastructure—PSCO and BHCE are permitted to recover, through a transmission cost adjustment, or TCA, clause, prudent costs incurred in planning, developing and completing construction or expansion of transmission facilities for which the PUC has granted a certificate of public convenience and necessity or has otherwise determined to be necessary. Through the TCA, the utilities may earn a cash return on construction work in progress for investments in grid reliability or new or upgraded transmission facilities. The TCAs are updated annually.

PSCO operates under a pipeline system integrity adjustment mechanism for its gas operations, through which the company recovers the costs associated with reliability improvements and compliance with certain federal safety regulations. The mechanism is to remain in place through 2018.

Other—PSCO utilizes an adjustment clause for steam service, under which it recovers the difference between its actual cost of fuel and the costs recovered in base rates.

PSCO shares with customers margins from generation-based short-term energy trading and proprietary trading through its fuel and purchased power adjustment mechanism. BHCE uses an off-system sales margin-sharing mechanism as a component of its fuel cost/purchased power expense cost adjustment mechanism.

Connecticut

Electric Fuel/Gas Commodity/Purchased Power—United Illuminating, or UI, and Connecticut Light and Power, or CL&P, no longer own generation, and both are permitted to recover, on a current basis, their full costs of providing generation service to those customers who do not choose an alternative supplier. These costs are flowed through to ratepayers outside of a rate case.

Decoupling—State law mandates the adoption of decoupling mechanisms for the electric and gas utilities. UI, CL&P, and Connecticut Natural Gas, or CNG, currently have decoupling mechanisms in place. Yankee Gas agreed to forgo the implementation of a decoupling mechanism until new base rates take effect. In a pending rate case, Southern Connecticut Gas, or SCG, is seeking a decoupling mechanism.

Generic Infrastructure—A system expansion reconciliation mechanism is in place that permits the gas utilities to reconcile gas-expansion-related revenue annually, between rate cases. CNG also utilizes a Distribution Integrity Management Program, or DIMP, mechanism that allows for recovery, between rate cases, of the costs associated with main replacement activity. Ratepayers do not see a separate charge on their bills. Instead, the DIMP charge is included in base distribution rates. SCG is seeking to implement a DIMP in its pending rate case.

Delaware

Electric Fuel/Gas Commodity/Purchased Power—In conjunction with the implementation of retail competition, Delmarva Power and Light's electric fuel adjustment was largely eliminated. Power to meet standard-offer-service needs is now procured competitively and the resulting costs are reflected in rates on a current basis.

Other—Chesapeake Utilities has a mechanism in place to recover variations in certain taxes and fees.

District of Columbia

Electric Fuel/Gas Commodity/Purchased Power —Fuel and purchased power adjustment clauses are permitted by law. However, with the onset of electric retail competition, Potomac Electric Power, or Pepco, divested most of its generation assets; the assets that were not divested have since been retired. Pepco purchases the power to meet its standard-offer-service, or SOS, requirements via a competitive bidding process, and prices paid by SOS customers reflect the weighted average of the winning bids; SOS prices are adjusted on a current basis.

Decoupling—A Bill Stabilization Adjustment mechanism, applied monthly, is in place for Pepco that is designed to mitigate the volatility of revenues and customer bills caused by abnormal weather and customer participation in energy efficiency programs.

Renewables Expense—Pepco's rates include a rider to fund the Sustainable Energy Trust Fund; amounts collected are remitted to the third-party Sustainable Energy Utility.

Generic Infrastructure—State law provides for the District to issue bonds, to finance, or securitize, a portion of the costs associated with a plan under which Pepco is to relocate certain above-ground distribution facilities below ground. In addition, the PSC is permitted to approve a rider mechanism to achieve rate recognition of the unsecuritized portion of the project. The PSC has approved the undergrounding program, known as the DC PLUG initiative, and established a rider for rate recognition of the investment. The commission order was appealed to the D.C. Court of Appeals.

The PSC has approved a $1 billion, 40-year accelerated pipeline replacement program for Washington Gas Light, or WGL, and approved a separate limited-issue recovery mechanism related to the first five years of the program.

Other—A gas administrative charge is part of WGL's purchased gas charge and provides for recovery of uncollectible expenses related to gas commodity charges, rather than recovering those expenses in base rates. WGL is also permitted to recover carrying costs on storage balances and over/undercollected gas costs through separate mechanisms. Pepco and WGL have a mechanism in place to recover variations in certain taxes and fees.

Florida

Generation Capacity—Electric utilities are permitted to recover all prudently incurred site selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle, or IGCC, power plants through the capacity cost recovery clause, or CCRC. A cash return on construction work in progress for nuclear plant construction and uprates and IGCC construction is also reflected in the CCRC.

Duke Energy Florida is permitted to increase base rates without a general rate case through a generation base rate adjustment, or GBRA, related to up to 1,800 MW of additional new generation in 2018. Adjustments under the GBRA are to reflect a 10.5% ROE and the most recent capital structure from the company's periodic surveillance reports that are filed with the PSC.

Tampa Electric implemented a rate increase through a GBRA to coincide with the completion of the conversion of units 2 through 5 of the Polk Power Station.

Generic Infrastructure—Peoples Gas System utilizes a rider that is adjusted annually for recovery of the costs associated with accelerating the replacement of cast iron and bare steel distribution pipes on its system. The smaller gas utilities, Florida Public Utilities, the Florida division of Chesapeake Utilities, and Pivotal Utility Holdings, use similar riders.

Other—Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage. The fuel and purchased power cost recovery clause reflects gains from economy energy sales.

Georgia

Electric Fuel/Gas Commodity/Purchased Power—As a result of the restructuring of the natural gas industry in Georgia, Atlanta Gas Light, or ATGL, no longer procures gas for its customers and, thus, is no longer subject to the purchased gas adjustment mechanism, or PGAM. The much smaller Liberty Utilities (Peach State Natural Gas), which is still regulated under a non-restructured framework, utilizes a non-automatic PGAM.

Decoupling—Liberty Utilities (Peach State Natural Gas) is subject to the Georgia Rate Adjustment Mechanism, or GRAM, an alternative regulatory framework. The GRAM provides for a "revenue true-up," under which the company is to compare actual revenues to the previous revenue projection. ATGL operates under a straight fixed-variable rate design.

Environmental Compliance—ATGL is authorized to recover clean-up costs related to former manufactured gas plant sites through an environmental response cost recovery rider, or ERCRR. Costs that are recoverable under the ERCRR include investigation, testing, remediation and/or litigation costs or other liabilities.

Generation Capacity—A nuclear construction cost recovery, or NCCR, tariff is in place for Georgia Power, or GP. The NCCR tariff enables GP to earn a cash return on construction work in progress related to the Plant Vogtle Units 3 and 4 nuclear units. The NCCR tariff is to be revised annually.

Generic Infrastructure—The PSC approved a Strategic Infrastructure Development and Enhancement, or STRIDE, program for ATGL in 2009, specifying infrastructure investments for the next ten years. Every three years, ATGL is required to file its proposed program for the next three years for PSC review and approval. The incremental costs associated with the program's investment are included in base rates each Oct. 1.

Hawaii

Generation Capacity/Generic Infrastructure—As part of their alternative regulation frameworks, Hawaiian Electric Company, Hawaii Electric Light Company and Maui Electric Company are permitted to recognize, between rate cases, rate base additions and increases in O&M expenses, and certain depreciation and amortization expenses.

Other—An integrated resource planning, or IRP, cost recovery rider is in place for the state's utilities to facilitate recovery of the planning costs associated with the IRP process.

Idaho

Electric Fuel/Gas Commodity/Purchased Power—Avista Corp.'s power cost adjustment enables the company to defer, in a balancing account, for subsequent recovery/refund to customers, 90% of the difference between actual net power costs and the amount included in retail rates. Idaho Power, or IP, has a similar mechanism in place with a sharing provision under which annual rate adjustments reflect 95% of the cost variations associated with water supply for hydro-electric production, wholesale energy prices and retail load changes. An energy cost adjustment mechanism is in place for PacifiCorp that allows for the recovery of 90% of the difference between actual power costs and those included in rates.

Decoupling—IP operates under a revenue decoupling mechanism, referred to as a Fixed Cost Adjustment, or FCA, which is designed to adjust the company's electric rates to recover fixed costs independent of the volume of energy sales. In 2015, the FCA was modified to replace weather-normalized sales with actual sales in the calculation of the FCA. There is a 3% cap on annual rate increases that may be implemented under the mechanism. Unrecovered balances are to be carried forward to future years, with interest.

Avista Corp. is to operate under an electric and gas revenue decoupling mechanism, referred to as a FCA, for an initial three-year term that extends through Dec. 31, 2018. The mechanism may be extended following a review by the parties following the end of the third year. There is a 3% annual cap on rate increases that may be implemented under the mechanism. Unrecovered balances are to be carried forward to future years, with interest.

Illinois

Electric Fuel/Gas Commodity/Purchased Power—Historically, the large electric utilities, namely Ameren Illinois, or AI, and Commonwealth Edison, or ComEd, were permitted to recover fuel costs and the energy component of purchased power costs through a monthly automatic fuel adjustment clause, or FAC. Their FACs were discontinued in conjunction with the implementation of electric industry restructuring. The power to meet the utilities' standard-offer-service, or SOS, obligations is now procured competitively; SOS costs and revenues are subject to an annual true-up mechanism.

Environmental Compliance—AI uses a hazardous materials adjustment clause rider, largely to address asbestos-related litigation and remediation costs. AI, ComEd, Peoples Gas Light and Coke, or Peoples, North Shore Gas, or North Shore, and Northern Illinois Gas, or NI-Gas, use riders to recover costs related to the investigation and cleanup of manufactured gas plants.

Generic Infrastructure—ComEd, North Shore and NI-Gas have riders in place to recover certain costs associated with maintaining infrastructure in accordance with requirements imposed by local governments. In accordance with state law, the ICC is permitted to approve adjustment clauses for the local gas distribution companies to recover the costs associated with their infrastructure replacement programs, and the ICC has done so for Peoples, NI-Gas, and AI.

Other—As permitted by state statutes, AI, ComEd, NI-Gas, Peoples, North Shore, and MidAmerican Energy utilize riders to facilitate recovery of variations in bad-debt costs. AI, ComEd, MidAmerican Energy, Peoples, North Shore, and NI-Gas have a mechanism in place to recover variations in certain taxes and franchise fees.

Indiana

Decoupling—Indianapolis Power and Light's, or IP&L's, Indiana Michigan Power's, or IMP's, Duke Energy Indiana's, or DEI's, Northern Indiana Public Service Company's, or NIPSCO's, and Southern Indiana Gas and Electric's electric energy efficiency riders provide for recovery of net lost revenues and shared savings, subject to commission approval. However, IP&L is permitted to defer lost revenues and NIPSCO's mechanism does not include savings sharing.

Environmental Compliance—State law allows the URC to authorize the electric utilities to recover, through a rate adjustment mechanism, 80% of the costs associated with certain federally-mandated emissions-control and transmission/distribution reliability projects. The remaining 20% of such costs are to be deferred for future recovery. Environmental cost recovery riders are in place for DEI, NIPSCO, IP&L and IMP. Through these riders, the utilities are permitted to recover related O&M costs and depreciation expense after the environmental facilities become operational, as well as a return on the related investment. These riders also provide for recovery of the net costs associated with the purchase of emission allowance credits.

Generation Capacity—With respect to DEI's Edwardsport integrated gasification combined-cycle plant, the company was authorized to earn a cash return on construction work in progress associated with the plant, which commenced commercial operation in 2013, through a rider; the company now recovers the plant's operating costs through that samerider.

Generic Infrastructure—State law allows the URC to authorize the utilities to implement a transmission, distribution and storage system improvement charge, or TDISC, rider to facilitate recovery of the costs associated with certain electric and gas infrastructure expansion projects, including those intended to improve safety or reliability, modernize the utility's system, or improve an area's economic development prospects. The URC has approved such a rider for DEI, Indiana Gas, Southern Indiana Gas and Electric's electric and gas operations and NIPSCO's electric and gas operations. IMP and NIPSCO use a rider to recover costs associated with certain government-mandated investments.

Other—DEI, IMP, IP&L and SIGECO are permitted to equally share with ratepayers, through a rider, off-system sales, or OSS, margins that vary from the amount reflected in the companies' base rates. NIPSCO allocates to ratepayers, through a rider, all OSS margins that vary from a base level. IMP uses a rider for recovery of costs associated with the AEP Power Pool capacity cost-sharing arrangement. SIGECO utilizes a semi-annual adjustment clause that reflects: municipal wholesale margins; net emission allowance costs; interruptible sales billing credits; non-fuel purchased power costs; and ratepayers' share of the difference between actual wholesale power margins and the level of such margins included in base rates. SIGECO and IG have riders in place for a portion of the incremental changes in unaccounted-for gas costs and the gas-cost component of bad debts. NIPSCO includes these costs in its gas cost adjustment filings.

Iowa

Environmental Compliance—Incremental revenues and costs associated with sales or purchases of emission allowances may be reflected in Interstate Power and Light's, or IP&L's, and MidAmerican Energy's energy adjustment clauses.

Other—MidAmerican Energy uses a rider to recover certain feasibility study costs related to its analysis of the merits of building a new nuclear plant. Black Hills/Iowa Gas Utility, IP&L and MidAmerican Energy have a mechanism in place to recover variations in certain taxes and franchise fees.

Kansas

Conservation Program Expense/Decoupling—State law allows the electric and gas utilities to request KCC approval to implement energy efficiency, or EE, related cost recovery mechanisms. Kansas City Power and Light, or KCP&L, and Empire District Electric recover the costs associated with energy efficiency programs through an EE rider. Westar Energy and Kansas Gas and Electric, or KG&E, participate in certain EE programs and recover program-related costs and the related lost revenues through the companies' EE cost recovery riders. These mechanisms were in place prior to the legislation. Weather normalization adjustment clauses are in place for Atmos Energy, Black Hills/Kansas Gas Utility, or KGU, and Kansas Gas Service, or KGS.

Generic Infrastructure—KCP&L has a rider in place to recover the costs associated with certain projects to underground transmission and distribution infrastructure. State law permits the local gas distribution companies to utilize a gas system reliability surcharge, or GSRS, mechanism to recover the costs associated with gas distribution system replacement projects between base rate proceedings, subject to annual true-up. The utilities are prohibited from utilizing GSRS mechanisms for periods exceeding five years; GSRS balances are to be reset to zero, with amounts recovered through the GSRS to be rolled into base rates in the utility's next rate proceeding. In addition, a utility may not request changes in the GSRS rate more often than every 12 months. Atmos, KGS and KGU have a GSRS in place.

Other—Although not an adjustment clause per se, the KCC is statutorily authorized to permit the utilities to file "abbreviated" rate cases, within 12 months of a commission rate order in the utility's most recent base rate proceeding. Such filings must incorporate all of the regulatory procedures, principles and rate-of-return parameters established by the KCC in that order.

KGU recovers 100% of the gas cost component of bad debt expense through the company's purchased gas adjustment clause filings. KCP&L, Westar, KG&E, and Empire District Electric, or Empire, flow to ratepayers, through their energy cost adjustment mechanisms, off-system sales margins that vary from a base level and the net cost of emissions allowances. KCP&L, Westar/KG&E, Empire, Atmos, KGU and KGS have a mechanism in place to recover variations in certain taxes and franchise fees.

Kentucky

Decoupling—Weather normalization adjustment mechanisms are in place for Atmos Energy, Columbia Gas of Kentucky, or CGK, Delta Natural Gas, or Delta, and Louisville Gas and Electric's, or LG&E's, gas operations. Duke Energy Kentucky, or DEK, LG&E, Atmos, CGK, and Delta utilize energy efficiency riders to facilitate recovery of costs associated with gas energy efficiency programs; these riders include certain incentive provisions and permit recovery of lost revenues related to these programs. LG&E, DEK, Kentucky Utilities, or KU, and Kentucky Power, or KP, also utilize a similar mechanism for their electric businesses.

Environmental Compliance—LG&E, KU, and KP are permitted to recover the costs associated with environmental-related investments, including the cost of emissions allowances, and earn a cash return on the related construction work in progress, through a cost recovery mechanism. Proceedings are conducted every two years to evaluate the operation of the mechanism and to set the level of such charges to be included in base rates.

Generation Capacity—KP utilizes a rider to recover the costs related to the retirement of the coal-fired Big Sandy Unit 1 and 2 plants, and a separate rider for certain non-fuel-related costs associated with operating the Big Sandy Unit 1 plant as a coal-fired unit through June 30, 2016, and as a gas-fired unit beginning July 1, 2016.

Generic Infrastructure—Atmos, CGK, LG&E, Delta and DEK utilize riders to facilitate recovery of certain costs associated with their gas distribution infrastructure replacement programs.

Other—Off-system sales, or OSS, sharing mechanisms are in place for DEK's electric operations and for KP. 100% of DEK's emission allowance sales margins flow to ratepayers through the OSS mechanism. LG&E and KU allocate a portion of their off-system sales margins to ratepayers through the fuel adjustment clause proceedings. Atmos, CGK, Delta, DEK, KP, LG&E, and KU have a mechanism in place to recover variations in certain taxes and franchise fees.

Louisiana - NOCC

Decoupling—Entergy New Orleans', or ENO's, fuel clause includes (for legacy Entergy Louisiana, Algiers service territory customers only) a provision that provides for the recovery of the lost contribution to fixed costs associated with customer participation in energy efficiency programs.

Environmental Compliance—An environmental adjustment clause rider is in place for ENO, through which the company recovers costs associated with the purchase and use of emission allowances.

Generation Capacity—A rider is in place for ENO through which the company reflects capacity costs associated with the Ninemile 6 plant.

Other—ENO uses a storm reserve rider for both its electric and gas operations.

Louisiana PSC

Decoupling—Energy efficiency, or EE, riders are in place for the state's electric utilities through which the companies recover costs associated with administering their EE programs and the lost contribution to fixed costs associated with customer participation in the programs. CenterPoint Energy Resources, Atmos Energy divisions Louisiana Gas Service, or LGS, and TransLouisiana Gas, or TLG, and the gas operations of Entergy Louisiana, or EL, utilize weather normalization adjustment mechanisms.

Environmental Compliance—The state's electric utilities may use an environmental adjustment clause, or EAC, to recover from ratepayers the costs associated with the acquisition of emissions credits to comply with federal, state and local environmental standards. In addition, the utilities credit ratepayers through the EAC any revenues associated with the sale or transfer of emission allowances.

Generation Capacity—A component of EL's formula rate plan, or FRP, provides for the recovery of costs associated with new generation and capacity additions, including the Ninemile 6 facility. Cleco Power's FRP includes provisions to reflect in rates certain capacity additions.

Generic Infrastructure— Cleco's FRP includes provisions to reflect in rates certain infrastructure costs. As part of their rate stabilization clauses, LGS and TLG have a mechanism in place that provides for the deferred recovery of costs associated with system integrity management programs. An infrastructure investment recovery rider is in place for EL's gas operations.

RTO-Related Transmission Expense—EL and Cleco recover certain transmission-related costs through their FRPs.

Other—Customers' share of Southwestern Electric Power's off-system sales margins flow through the company's fuel adjustment clause. Cleco Power and EL have securitization-related riders in place. Economic development riders are in place for EL, Cleco and Southwestern Electric Power.

Maine

Fuel Costs/Purchased Power Costs—Electric fuel adjustment clauses are no longer utilized due to the implementation of retail choice. For the most part, the state's electric utilities no longer own generation, and by law are not allowed to provide standard offer service, or SOS. SOS providers are selected through a bidding process conducted by the PUC. The full cost of SOS is recovered from ratepayers.

Decoupling—Central Maine Power, or CMP, is subject to a full revenue decoupling mechanism, with any related annual adjustments capped at 2% of distribution revenues, and any undercollections in excess of the cap to be deferred for future recovery. No cap applies to the amount of over-collections to be returned to ratepayers.

Environmental Compliance—Northern Utilities recovers manufactured gas site remediation expenses through an environmental remediation charge that is adjusted on a semi-annual basis.

Generic Infrastructure—Northern Utilities utilizes a targeted infrastructure replacement adjustment, or TIRA, that provides for recovery of the company's investments in targeted operational and safety-related infrastructure replacement and upgrade projects. A successor TIRA is pending as part of the company's pending rate case.

Other—CMP is permitted to recover variations in storm costs versus the levels included in base rates through a rider.

Maryland

Electric Fuel/Purchased Power—Historically, electric utilities were permitted to recover the fuel and energy portion of purchased power costs through the electric fuel rate, or EFR. The EFR was eliminated, coincident with the implementation of competition in the provision of electric supply. The utilities continue to provide electric supply service to customers who do not select an alternative generation supplier; the power to meet these requirements is obtained via competitive bids and the costs are recovered from ratepayers on a current basis.

Conservation Program Expense—Maryland's electric and gas utilities have riders in place, which are adjusted annually, to reflect recovery of electric and gas energy efficiency and demand-side management program costs that are not included in base rates.

Decoupling—Columbia Gas of Maryland, or CGM and Washington Gas Light, or WGL, have revenue normalization adjustment mechanisms in place for residential customers only. However, the companies have separate weather normalization mechanisms in place that apply to all customer classes.

Generic Infrastructure—Potomac Electric Power, or Pepco, uses a grid resiliency charge to recover the costs associated with its accelerated-feeder-replacement program. A similar program and rider are in place for Delmarva Power and Light. A reliability improvement plan and an associated rider are in place for Baltimore Gas and Electric, or BGE. Court review of the program is pending.

State law permits the Maryland PSC to authorize the gas utilities to implement riders to recover costs associated with approved accelerated infrastructure replacement programs, establishing the Strategic Infrastructure Development and Enhancement, or STRIDE, Program. The PSC has approved a gas STRIDE program and an associated rider for BGE, WGL, and CGM.

Other—BGE, CGM, Potomac Edison, Pepco and WG have a mechanism in place to recover variations in certain taxes and fees.

Massachusetts

Electric Fuel/Gas Commodity/Purchased Power—Quarterly electric fuel and purchased power adjustments were eliminated coincident with the start of retail competition. Rates for basic service, known as default service, are market-based; such rates reflect the competitive contracts for basic service supply entered into by the distribution utility. The utilities are not at risk for fluctuations in market prices.

Conservation Program Expense/Environmental Compliance/Other—The DPU has adopted energy efficiency reconciliation factors, or EERF, for the state's electric utilities to recover the costs associated with the state's electric energy efficiency investments that are in excess of the level collected from other funding sources.

Local gas distribution adjustment clauses, or LDACs, are in place to reflect recovery of gas-distribution-related costs that are not included in base rates, such as demand-side management costs, environmental response costs associated with manufactured gas plants, residential arrearage management programs, low income discounts, pension costs and certain litigation expenses.

Renewables Expense/Generation Capacity—A solar cost adjustment tariff is in place for Western Massachusetts Electric Company's, or WMECO's, and Massachusetts Electric's, or ME's, investments in certain solar generation facilities.

Generic Infrastructure—Through the LDAC, the utilities may recovery the revenue requirement associated with their targeted infrastructure recovery factors, or TIRFs, and gas system enhancement programs, or GSEP, investment,

Under state law, each of the state's LDCs files with the DPU a plan called a "Gas System Safety Enhancement Program,", or GSEP, to address aging or leaking natural gas infrastructure. The related costs/investments may be recovered through a GSEP portion of the LDAC.

ME's decoupling mechanism includes a tracking mechanism to reflect incremental capital investment, subject to certain limitations. A capital cost adjustment mechanism is in place for Fitchburg Gas and Electric's, or FG&E's, electric division that permits the company to recover costs associated with post-test-year capital additions outside of a rate case, subject to certain restrictions.

Michigan

Decoupling—The Michigan PSC had approved the implementation of electric revenue decoupling mechanisms, or RDMs, for Consumers Energy, or CE, Upper Peninsula Power, or UPP, and DTE Electric, or DTE-E; however, the Michigan Court of Appeals has ruled that the PSC does not have statutory authority to approve RDMs for electric utilities. In addition, legislation enacted in December 2016, permits the PSC to adopt electric revenue decoupling mechanisms only for small electric utilities.

State law permits a gas utility that spends at least 0.5% of its revenue on energy efficiency programs to institute an RDM. Gas RDMs are currently in place for DTE Gas, or DTE-G, and CE.

Generic Infrastructure—DTE-G utilizes an Infrastructure Recovery Mechanism that enables it to earn a return of, and on, the costs associated with capital investment in the company's meter move-out, accelerated main replacement and pipeline integrity programs. In a recent rate case decision, the PSC authorized CE's gas operations an investment recovery mechanism that enables the company to recover incremental capital investments beyond the test year in both 2018 and 2019, subject to reconciliation.

RTO-Related Transmission Expense—CE, DTE-E and UPP recover transmission costs through the power supply cost-recovery mechanism.

Minnesota

Decoupling—Minnesota Energy Resources, or MER, is operating under a pilot, full revenue decoupling mechanism, or RDM, that applies to the company's residential and small commercial/industrial rate classes that includes sharing provisions. The pilot is to remain in place through Dec. 31, 2019.

CenterPoint Energy Resources, or CER, is operating under a pilot, three-year, full RDM that expires in 2018. The RDM applies to all customer classes except market-rate customers, subject to a cap on annual adjustments.

A three-year pilot decoupling mechanism was implemented in 2016 for Northern States Power-Minnesota's, or NSP-M's, residential, small commercial, and industrial non-demand classes. The plan includes a cap on the revenue adjustments that may be implemented under the mechanism.

Generic Infrastructure—NSP-M uses a rider to recover the costs associated with certain gas infrastructure upgrades, especially those that are safety-related, outside of a general rate case.

Mississippi

Decoupling—Atmos Energy utilizes a weather normalization adjustment rider that is in place during the months of November through April and is adjusted monthly during that time. Entergy Mississippi, or EM, Mississippi Power, or MP, and Atmos have energy efficiency, or EE, riders in place that provide for recovery of EE program costs and the lost contributions to fixed costs associated with such programs.

Environmental Compliance—EM and MP are permitted to recover emissions allowance expenses through their fuel adjustment clauses. For MP, such costs may include the cost of capital, associated with PSC-approved environmental projects.

Other—EM and MP have riders in place related to the securitization of storm costs. EM uses an ad valorem tax adjustment rider. A similar mechanism has been in place for MP for many years.

Missouri

Conservation Program Expense/Decoupling—The local gas distribution companies may request Missouri PSC approval of a mechanism to reflect the impact on revenues of changes in customer usage due to variations in weather and/or conservation. Kansas City Power and Light, or KCP&L, has in place a demand-side programs investment mechanism that provides for recovery of program-related costs and a related "throughput disincentive." KCP&L-Greater Missouri Operations, or GMO, and UE have similar mechanisms in place for their electric operations.

Renewable Energy—The PSC's rules specify that the electric utilities may file for a renewable energy standards rate adjustment mechanism, or RESRAM, to reflect prudently incurred costs or a pass-through of benefits received, as a result of compliance with the state's renewable energy standards. The RESRAM is to be capped at a 1% annual rate impact. GMO has a RESRAM in place.

Environmental Compliance—The PSC's rules pertaining to Environmental Cost Recovery Mechanisms, or ECRMs, specify that a portion of the utility's environmental costs may be recovered through an ECRM, subject to a cap. None of the utilities currently have an ECRM in place; however, Empire District Electric, or Empire, GMO and UE recover emissions allowance costs through their FACs.

Generic Infrastructure—KCP&L, GMO and UE use a rider to recover costs associated with certain government-mandated investments. Liberty Utilities (Midstates Natural Gas), Laclede Gas, Missouri Gas Energy, or MGE, and UE utilize an infrastructure system replacement rider to recover costs associated with certain gas distribution system replacement projects.

RTO-Related Transmission Expense—Empire's, KCP&L's, GMO's and UE's FACs reflect variations in certain transmission-related costs.

Other—Off-system sales margins that vary from the levels included in base rates flow through the FACs of Empire, KCP&L, GMO and UE. Liberty Utilities (Midstates Natural Gas), Empire, KCP&L, GMO, Laclede, MGE and UE have a mechanism in place to recover variations in certain taxes and franchise fees.

Montana

Electric Fuel/Gas Commodity/Purchased Power—In accordance with the state's restructuring statutes, NorthWestern Corp. sold its generation assets and entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort customers. NorthWestern recovers supply costs through a cost recovery mechanism.

Decoupling—MDU utilizes a mechanism to recover the costs associated with gas conservation programs, as well as to recoup revenues lost as a result of the programs.

Other—A competitive transition charge mechanism is in place for NorthWestern through which the company recovers electric-restructuring-related out-of-market costs associated with certain purchased power contracts. A similar transition charge is in place for the company's gas operations. NorthWestern is also currently reflecting, in its gas commodity mechanism on an interim basis, costs related to certain natural gas production assets it recently acquired, pending a review by the PSC. For MDU, off-system sales margins are shared by ratepayers and shareholders on a 90%/10% basis through the fuel clause.

Nebraska

Generic Infrastructure—The gas utilities may seek approval to use an infrastructure system replacement cost recovery, or ISRCR, rider to achieve timely recovery of certain capital investments outside of a general rate case. Black Hills Nebraska Gas Utility has an ISRCR rider in place. Black Hills Gas Distribution, or BHGD, has a forward-looking system safety and integrity rider in place.

Other—BHGD recovers external rate case expenses of the Office of the Public Advocate and the PSC that are assessed to the utility through a separate mechanism. All of the utilities have line items on their bills through which variations in franchise fees are recovered.

Nevada

Decoupling—The lost revenues associated with energy efficiency and conservation programs for Sierra Pacific Power and Nevada Power are recovered using a periodically adjusted balancing account, referred to as the lost revenue adjustment mechanism.

State law and PUC rules contain provisions, including revenue decoupling, to address disincentives to gas company participation in energy conservation programs.

Generic Infrastructure—PUC rules allow for the establishment of a gas infrastructure replacement mechanism that will permit the utilities to recover, between rate cases, the revenue requirement associated with their gas infrastructure replacement projects. Southwest Gas currently has such a rider in place.

Other—Southwest Gas utilizes a mechanism designed to allow the company to recover from, or refund to, ratepayers the difference between actual bad debt expenses and the level reflected in base rates.

New Hampshire

Electric Fuel/Gas Commodity/Purchased Power—Fuel and purchased power adjustment clauses had been utilized prior to the implementation of retail choice in the early 2000s. Public Service Company of New Hampshire, or PSNH, now recovers its power costs through a periodically-adjusted default service rate.

Liberty Utilities (Granite State Electric) and Unitil Energy Systems sold their generation as part of their restructuring agreements. These distribution-only companies supply default energy service through a request-for-proposals process supervised by the PUC.

Decoupling—In August 2016, the PUC established an energy efficiency resource standard, or EERS, for New Hampshire's electric and gas utilities. The EERS is to become effective Jan. 1, 2018. The utilities implemented lost revenue adjustment mechanisms, or LRAMs, effective Jan. 1, 2017, to recover lost revenue due to the installation of energy efficiency measures. The PUC ordered the utilities to seek approval of a decoupling mechanism or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before. Liberty Utilities is seeking a decoupling mechanism as part of its pending natural gas rate case.

Generic Infrastructure —A cast iron/bare steel rate adjustment mechanism is in effect for Liberty Utilities (EnergyNorth Natural Gas). Reliability enhancement and vegetation management programs and accompanying riders are in effect for Liberty Utilities (Granite State Electric), PSNH, and Unitil Energy Systems. The programs provide for recovery of both the capital investment and increases to operation and maintenance expense necessary for ongoing system reliability and vegetation management efforts.

New Jersey

Electric Fuel/Purchased Power/Gas Commodity— The electric utilities procure power to meet customer basic generation service in the wholesale market and are permitted to flow these costs to ratepayers on a dollar-for-dollar basis through the basic generation service charge. However, costs associated with buyout/buy-down of above-market-priced purchased power contracts with non-utility generators and costs associated with any remaining purchase requirements are recovered through a separate non-bypassable charge. Gas supply service is also competitively provided in New Jersey. Basic gas supply service, or BGSS, charges for non-switching residential and small commercial customers are adjusted periodically to reflect fluctuations in gas commodity prices.

Conservation Program Expense—Costs associated with the NJ Clean Energy Program are included for recovery through the non-bypassable societal benefits charge on customer bills. Certain utilities have incremental energy efficiency/conservation programs in place, the costs of which may be recovered through rider mechanisms.

Decoupling—Weather normalization clauses are in place for Pivotal Utility Holdings, or PUH, and the gas operations of Public Service Electric and Gas, or PSEG. A version of a revenue decoupling mechanism is in place for New Jersey Natural Gas, or NJNG, and South Jersey Gas, or SJG. Operation of the mechanisms is contingent on the companies achieving certain capacity-reduction targets and earnings tests as specified in their BPU-approved conservation incentive programs.

Environmental Compliance—The electric and gas utilities were permitted to recover through a charge, costs, including a return on the related investment, associated with participation in the Regional Greenhouse Gas Initiative. Participation in the Initiative was suspended by Gov. Christie in 2011, but the utility provisions of the state law remain in place, which has sparked a considerable amount of controversy. Jersey Central Power & Light, PUH, PSEG, NJNG and SJG are permitted to recover costs associated with former manufactured gas plant site cleanup outside of base rates through an adjustment mechanism.

Generic Infrastructure—Following Hurricane Sandy, the BPU directed the utilities to develop mitigation and hardening infrastructure modernization plans, and indicated that it would be open to innovative cost-recovery mechanisms for such plans. The BPU subsequently approved modernization plans and related recovery mechanisms for several utilities: PSEG— the Energy Strong program; Atlantic City Electric — PowerAhead; Rockland Electric —Storm Hardening Program; NJNG — the Reinvestment in System Enhancement program, and Safe Acceleration and Facility Enhancement program; PUH — Elizabethtown Natural Gas Distribution Utility Reinforcement Effort; and, SJG — the Storm Hardening and Reliability Program.

Other—All of the utilities have a mechanism in place to recover variations in certain taxes and fees. In addition, the electric utilities recover certain costs associated with low-income customer assistance programs and other public policy driven initiatives through a societal benefits charge; costs associated with the restructuring-related buyout/by-down of electric non-utility generation contracts and other regulatory asset balances are recovered through non-by-passable charges.

New Mexico

Environmental Compliance—An SO_2 rider is in place for Public Service Co. of New Mexico, or PSNM, through which customers are credited with their share of revenues from allowance sales.

Generic Infrastructure—PSNM has riders in place that are designed to recover costs associated with undergrounding distribution projects in Rio Rancho and Albuquerque.

Other—All of the utilities have a mechanism in place to recover variations in certain taxes and franchise fees.

New York

Electric Fuel/Gas Commodity/Purchased Power—Historically, all energy utilities used an electric fuel adjustment clause, or FAC. 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.

Generic Infrastructure—The state's gas utilities may implement riders to recover carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of leak prone pipe above targeted miles established in rates.

North Carolina

Conservation Program Expense—In addition to recovery of program costs, the NCUC has authorized the major electric utilities to retain a percentage of the net savings associated with their conservation programs.

Renewables Expense—Costs incurred by electric utilities to procure renewable energy are recoverable through the fuel adjustment clause, or FAC, and the renewable energy portfolio standard, or REPS, rider subject to certain caps.

Environmental Compliance—The costs of certain re-agents, such as limestone, used in reducing or treating electric power plant emissions may be recovered through the fuel adjustment clause.

Generic Infrastructure—Piedmont Natural Gas uses an integrity management rider, or IMR, that allows the company to track and recover capital expenditures incurred to comply with federal pipeline safety and integrity requirements outside of a general rate case. Public Service Company of North Carolina uses an IMR to recover capital expenditures closed to plant in service after June 30, 2016, related to the company's transmission and distribution pipeline integrity management programs.

North Dakota

Decoupling—MDU Resources', or MDU's, gas operations are subject to a weather normalization adjustment mechanism that is in effect for the winter heating season from Nov. 1 through May 1. Northern States Power-Minnesota, or NSP-M, operates under straight fixed-variable gas rates.

Generation Capacity—MDU operates under a generation resource recovery rider through which it recovers costs associated with its Reciprocating Internal Combustion Engine Project at its Lewis & Clark Station, which will then be rolled into base rates by Jan. 1, 2020. The rider previously recovered costs associated with the 88-MW, simple cycle gas turbine Heskett III facility. Those costs were rolled into base rates following a stipulation approved by the commission in June 2017.

Environmental Compliance/Generic Infrastructure—The electric utilities are permitted to earn a cash return on construction work in progress through a separate rate adjustment mechanism for investments in transmission infrastructure and for federally-mandated environmental compliance projects. Once the facilities achieve commercial operation, they are reflected in rate base as part of a general rate proceeding, and the mechanism terminates. MDU and Otter Tail Power, or OTP, are operating under separate transmission and environmental cost recovery riders. NSP is operating under a transmission cost recovery rider.

Renewables Expense — All three utilities recover costs associated with investments in renewable energy facilities through a renewable resource cost recovery rider. MDU recovers costs associated with its Cedar Hills, Diamond Willow and Thunder Spirit wind facilities.

Other—Through NSP-M's fuel and purchased power adjustment, or FPPA, clause, the company shares equally with ratepayers prospective "non-asset-based" wholesale power margins, or WPMs. Through its FPPA clause, OTP allocates asset-based WPMs on an 85%/15% basis to ratepayers and shareholders, respectively.

Ohio

Electric Fuel/Gas Commodity/Purchased Power/Generic Infrastructure/Other—As a result of electric industry restructuring, the utilities operate under electric security plans, or ESPs, that provide for the pass through of the utilities' cost of power to serve standard-service-offer customers.

The current ESPs for Cleveland Electric Illuminating, or CEI, Ohio Edison, or OE, and Toledo Edison, or TE, include delivery capital recovery riders that reflect a return of, and on, incremental distribution, sub-transmission, and general plant-in-service investments not already included in the companies' base rates.

Under Duke Energy Ohio's, or DEO's, current ESP, the company's generation requirements for non-switching customers are procured and priced through a competitive bid process, or CBP. The related riders are fully bypassable for switching customers.

Ohio Power's, or OP's, ESP allows the company to utilize riders for costs related to distribution investment, enhanced service reliability and storm damage recovery.

Dayton Power and Light's, or DP&L's, ESP, includes a Service Stability Rider to permit the company to maintain its financial health and to have an opportunity to earn a reasonable return on equity. DP&L also uses an Infrastructure Investment Rider for recovery of costs related to advanced meter infrastructure and/or SmartGrid deployment.

East Ohio Gas, or EOG, Columbia Gas of Ohio, or CGO, and Vectren Energy Delivery of Ohio, or VEDO, had previously obtained their gas supplies through negotiated bilateral contracts, but now the companies conduct an auction that allows suppliers to compete to supply portions of the gas supply requirements. Customers who do not choose a specific competitive supplier are randomly assigned a supplier based on the auction results. DEO is the only major gas utility in the state to continue to use the gas cost recovery clause.

Decoupling/Conservation Program Expense—The ESPs for each of the Ohio electric utilities include a rider that allows for recovery of energy efficiency program costs and lost distribution margin associated with these programs. OP has a full pilot decoupling mechanism in place for residential and small commercial customers. Ohio's gas distribution companies, namely EOG, CGO, VEDO and DEO all operate under straight fixed-variable prices.

Environmental Compliance—DEO recovers certain costs related to former manufactured gas plant sites through a rider.

Generic Infrastructure—The current ESPs in place for CEI/OE/TE, OP and DEO include a rider(s) that reflects a return of, and on, incremental distribution related investments not already included in the company's base rates. CGO has a rider in place for infrastructure replacement costs. VEDO has a rider in place through which it recovers the costs associated with an accelerated main and service line replacement program. EOG has riders in place to recover costs related to its pipeline infrastructure replacement program and its installation of automated meter reading equipment. DEO uses an Accelerated Main Replacement Program rider to recover the costs associated with its gas delivery infrastructure improvement program.

Other—All of the utilities have a mechanism in place to recover variations in certain taxes and fees. DEO uses Rider Manufactured Gas Plant, or MGP, to recover PUC-approved costs associated with the company's environmental remediation of MGP sites. CEI/OE/TE, OP, DEO, EOG, CGO and VEDO have riders in place to recover variations in uncollectible expense.

Oklahoma

Conservation Program Expense/Decoupling—Oklahoma Gas and Electric, or OG&E, and Public Service Oklahoma, or PSO, utilize riders to recover the costs associated with energy efficiency programs, the related lost revenues and certain incentives. CenterPoint Energy Resources, or CER, and Oklahoma Natural Gas, or ONG, utilize weather normalization mechanisms and also recover the costs associated with their energy efficiency programs and certain incentives through their performance-based ratemaking plan riders.

Environmental Compliance/Other—OCC rules permit the commission to approve requests to recover costs associated with environmental compliance costs through a rate rider. OG&E's storm cost recovery rider includes provisions that require a credit to ratepayers for the Oklahoma-jurisdictional portion of net revenues received from the sale of SO_2 credits. PSO recovers the costs associated with certain chemical reagents through its fuel cost adjustment, or FCA, rider.

Generic Infrastructure—OG&E recovers, through a rider, costs associated with certain transmission projects it constructs. PSO utilizes a rider for recovery of incremental vegetation management, under-grounding costs and system-hardening/grid resiliency costs. PSO also uses an automated metering infrastructure, or AMI, rider to recover the costs associated with installing AMI equipment in its service territory.

Other—OG&E uses a storm-cost recovery rider to reflect any differences between the level of storm costs reflected in base rates and the level of such costs actually incurred in a given year. Ratepayers' share of OSS margins flow through PSO's FCA rider. OCC rules permit the Commission to allow utilities to recover security/safety-related costs through a separate charge/rate rider. OG&E, PSO, CER and ONG have a mechanism in place to recover variations in certain taxes and franchise fees. ONG has a rider in place for costs related to lost, used and unaccounted-for gas.

Oregon

Decoupling—A partial electric revenue decoupling mechanism is to be in effect for Portland General Electric, or PGE, until year-end 2019. The mechanism is designed to provide for the recovery of the revenue shortfall resulting from reduced consumption patterns associated with residential and certain commercial customers' conservation efforts.

Northwest Natural Gas, or NWNG, uses a decoupling mechanism designed to counteract the impact on revenues of changes in average residential and commercial customers' consumption patterns due to conservation efforts. The company has a separate weather-adjusted rate mechanism in place for these customers.

Cascade Natural Gas', or CNG's, partial decoupling mechanism, which adjusts for both conservation-related-demand fluctuations and deviations from normal weather, is to be in place until Jan. 1, 2020.

A full decoupling mechanism is in place for Avista's residential and commercial rate groups. The mechanism is to be reviewed by the PUC in September 2019.

Environmental Compliance—CNG utilities an environmental remediation cost adjustment to recover costs for a former manufactured plant. NWNG utilizes a site remediation and recovery mechanism to provide for recovery of costs incurred, and that continue to be incurred, for environmental remediation of legacy manufactured gas plant operations.

Pennsylvania

Electric Fuel/Purchased Power/Gas Commodity/Renewables Expense—Historically, electric utilities were permitted to recover fuel and purchased power costs through a semi-automatic adjustment mechanism,; however, in conjunction with electric industry restructuring, the mechanism was eliminated. Generation required to meet provider-of-last-resort, or POLR, obligations for each company is competitively procured and priced. Renewable resource requirements are included in this process.

Decoupling—Columbia Gas of Pennsylvania, or CGP, has a weather normalization adjustment in place for residential customers. In January 2016, the PUC opened a generic investigation into alternative ratemaking strategies including revenue decoupling mechanisms. The proceeding is ongoing.

Generic Infrastructure—State law allows the PUC to approve automatic adjustment clauses to recognize, between general rate cases, utility investments in Long-Term Infrastructure Improvement Programs that were approved by the PUC ahead of time.

Separately, Metropolitan Edison, or MetEd, Pennsylvania Electric, or Penelec, Pennsylvania Power, or PPC, and West Penn Power, or WPP, recover incremental costs associated with smart-meter-deployment plans through a rider.

Other—All of the utilities have a mechanism in place to recover variations in certain taxes and franchise fees. PECO recovers nuclear decommissioning costs through a rider. PPL-E recovers universal service program costs through a rider. MetEd, Penelec, PPC and WPP also have riders in place for universal service and uncollectibles costs.

Rhode Island

Electric Fuel/Gas Commodity/Purchased Power—Prior to the implementation of electric industry restructuring, automatic electric fuel adjustment clauses were used by the utilities. In accordance with the restructuring law and PUC-approved restructuring plans, investor-owned utilities are to provide standard offer service to customers who do not select an alternative provider through 2020. The cost of providing this service is fully recoverable, with such rates reset on a periodic basis.

Generic Infrastructure—State law permits Narragansett Electric, or NE, to submit, for PUC approval, annual infrastructure spending plans for its electric and gas operations, as well as recovery of expenses associated with an inspection and maintenance program and vegetation management program. Approved costs may be recovered through a rider.

Other—A pension adjustment mechanism is in place for NE's electric and gas operations that reconciles actual pension and other-post-employment-benefits expense to the level reflected in base rates. NE recovers electric commodity-related uncollectibles, including associated administrative costs, through its standard offer service rate. In addition, the company recovers transmission-related bad debt through a transmission-related uncollectible mechanism. NE reflects credits associated with margins from non-firm sales and transportation, earnings sharing and service quality adjustments through the DAC.

South Carolina

Decoupling—Weather normalization adjustments are in place for the gas operations of South Carolina Electric and Gas, or SCE&G, and Piedmont Natural Gas that apply only to residential and small commercial customers.

Environmental Compliance—Emissions allowance costs and the cost of certain materials used in reducing or treating electric power plant emissions are reflected in the fuel clause.

Generation Capacity—Statutes allow the PSC to issue a base load review act, or BLRA, order, which constitutes an upfront determination that a plant is "used and useful," and that associated proposed capital expenditures are prudent and ultimately should be reflected in rates as long as the plant is constructed within the estimated construction schedule, including contingencies, and capital budget.

For nuclear plants only, if requested by a utility, the BLRA order is to specify initial revised rates reflecting the utility's pre-construction and development costs. At least one year after its filing of a BLRA application, and no more frequently than annually thereafter, the utility is permitted to file for PSC approval of revised rates reflecting a cash return on a nuclear plant's construction work in progress, or CWIP. The PSC has issued a BLR order for SCE&G's two-unit expansion of its V.C. Summer nuclear plant, and the company is currently earning a cash return on the plant's CWIP. However, given SCE&G's July 31, 2017 decision to cease construction and abandon the two new units, the ultimate ratemaking for the company's investment remains to be determined.

South Dakota

Conservation Program Expense/Decoupling—A demand-side management, or DSM, cost adjustment mechanism is in place for Northern States Power-Minnesota, or NSP-M, through which the company recovers costs associated with DSM/efficiency programs. The mechanism includes a 30% bonus to account for lost margins related to DSM/efficiency measures. Black Hills Power, or BHP, operates under an efficiency adjustment rider through which the company recovers the cost of its energy efficiency programs, as well as any lost revenues associated with the programs. Weather impacts are not reflected in the mechanism.

Generation Capacity/Generic Infrastructure—NSP-M utilizes an infrastructure rider to recover costs associated with certain generation, transmission and distribution capital additions once the related facilities have achieved commercial operation and to reflect certain changes in property taxes.

Other—Through its fuel and purchased power adjustment clause, or FPPAC, BHP credits ratepayers a portion of the margins from renewable energy credit sales and power marketing income. NSP-M operates under certain wholesale power margin sharing provisions, and allocates ratepayers' share of any such margins through its fuel clause. NSP-M also credits ratepayers a portion of revenues generated from renewable energy credit sales through its fuel clause.

Tennessee

Decoupling—Weather normalization adjustment, or WNA, clauses are in place for Atmos Energy and Piedmont Natural Gas, or PNG. A full revenue decoupling mechanism is currently in place for Chattanooga Gas', or CG's, residential and small commercial customers. A WNA rider is also in place for CG's industrial, commercial, and other customers that do not operate under the decoupling mechanism.

Other—Atmos Energy, PNG and CG utilize riders related to capacity management and release, off-system sales and capacity assignment.

Atmos and CG operate under riders through which the companies share with ratepayers gross profit margin reductions associated with large industrial or commercial customers that are served under negotiated contracts and are able to bypass the utilities' distribution system. Through its purchased gas adjustment rider, PNG recovers margin losses associated with bypassable customers being served under negotiated contracts.

Texas PUC

Electric Fuel/Purchased Power—For companies that implemented retail competition, i.e., within the Electric Reliability Council of Texas, or ERCOT, the transmission and distribution utilities do not have provider-of-last-resort/standard-offer-service obligations. Retail electric providers offer generation service at marked-based rates.

For electric utilities that have not implemented retail competition, fuel and purchased power costs are recovered through a separate fuel factor.

Generic Infrastructure—The PUC may approve periodic distribution cost recovery factors, or DCRFs for both vertically integrated and transmission and distribution-only electric utilities. The PUC may prohibit a utility from implementing a rate change under the mechanism if the Commission determines that the utility is earning in excess of its authorized return prior to the adjustment. Amounts approved for recovery under the DCRF are to be rolled into base rates in the utility's subsequent rate case. DCRFs have been approved for Entergy Texas, or ETI, CenterPoint Energy Houston, or CEHE, Southwestern Electric Power, or SWEPCO, TCC and TNC. A request for a DCRF by Southwestern Public Service, or SWPS, is pending.

State law permits the utilities to recover costs associated with deployment of advanced metering technology through a separate charge. Advanced metering riders are in place for AEP Texas Central, or TXC, AEP Texas North, or TXN, CEHE, Oncor, Sharyland Utilities and TNMP.

For the service territories in which retail competition has been implemented may implement, outside of base rate cases, rate changes to reflect new transmission facilities through an interim transmission cost-of-service mechanism, or TCOS. TCOS mechanisms have been approved for TXC, TXN, CEHE, Oncor and Texas-New Mexico Power, or TNMP, as well as transmission-only entities such as Cross Texas Transmission, Electric Transmission Texas, Lone Star Transmission and Wind Energy Transmission of Texas.

Utilities that have not implemented retail competition, i.e., El Paso Electric, or EPE, ETI, SWEPCO and SWPS, may also file for adjustments to reflect new investment in transmission facilities between rate cases. This procedure is known as a transmission cost recovery factor, or TCRF, mechanism.

RTO-Related Transmission Expense—Transmission revenue requirements established through either base rates or the TCOS procedure are allocated among the distribution service providers, or DSPs, within ERCOT based on PUC-approved, load-based allocation factors, established under the Commission's "transmission matrix." The DSPs are permitted to adjust rates twice annually to reflect changes in wholesale transmission costs assigned to the DSP by ERCOT. These changes flow through a mechanism also known as a TCRF, which is in place for CEHE, Oncor, Sharyland, TNMP, TXC and TXN.

Other—A rider is in place for ETI that allows for recovery of variations in storm costs versus the level included in base rates. CEHE, ETI and TNMP have adjustment clauses in place to reflect changes in municipal franchise fees. EPE has a rider in place to recover lost revenue associated with the provision of discounted service to military bases, while SWPS recovers lost revenue associated with the provision of discounts to state universities through a rider.

Texas RRC

Gas Commodity Costs—Purchased gas cost adjustment clauses may be implemented under certain circumstances. Atmos Energy, Texas Gas Service, or TGS, and CenterPoint Energy Resources, or CERS, have such mechanisms in place. Uncollectibles are included in the gas cost recovery factors for Atmos and TGS, but are not included for CERS.

Decoupling—Weather normalization adjustments are in place for Atmos and TGS.

Generic Infrastructure—Surcharge mechanisms for gas reliability infrastructure program, or GRIP, costs are in place for CERS' Houston, South Texas, Beaumont/East Texas and Texas Coast Divisions. A similar mechanism is in place for most of the cities served by Atmos' Mid-Tex and West Texas Divisions. Operations in the City of Dallas and its environs, which are part of the Mid-Tex Division, are subject to a "Dallas Annual Rate

Review Mechanism" that takes into account several factors including new infrastructure investment. The remaining Mid-Tex Division is subject to an annual formula ratemaking tariff, known as the annual Rate Review Mechanism, or RRM, which takes into account several factors including new infrastructure investment. Certain cities within the West Texas division are subject to a similar tariff, while others, such as Amarillo and Lubbock, operate with annually-updated GRIP mechanisms. An annual cost-of-service adjustment mechanism, similar to the Rate Review Mechanism, is in place for TGS.

Other—Gas-commodity-related uncollectibles are recovered through Atmos' GCRF.

Utah

Decoupling—A weather normalization adjustment, or WNA, is in place for Questar Gas; however, customers may elect not to participate in the WNA. Questar Gas also utilizes a conservation-enabling tariff, or CET, which decouples non-gas revenues from the volume of gas used by general service, or GS, customers. Under the CET, a margin-per-customer target is specified for each month, with non-weather-related differences to be deferred and recovered from, or refunded to, GS customers via periodic rate adjustments. Annual CET accruals are limited to 5% of base distribution non-gas, or DNG, revenues. Per a settlement adopted in the PSC's review of Dominion Resources' acquisition of Questar Gas parent Questar Corp., incremental CET accruals that exceed the 5% cap do not earn interest, as had previously been permitted. The amortization of CET accruals is limited to 2.5% of total Utah-jurisdictional base DNG GS revenues. Together, the WNA and CET act as a full revenue decoupling mechanism.

Renewables Expense—PacifiCorp operates under a renewable energy credit, or REC, mechanism that tracks variations in REC revenues from a base level established in the most recent general rate case, with any differences to flow to customers via an annual credit or surcharge. A separate adjustment mechanism is in place through which PacifiCorp recovers costs associated with its solar program.

Generic Infrastructure—A pilot infrastructure replacement adjustment mechanism is in place for Questar Gas that permits the company to recover, between rate cases, the incremental costs associated with the replacement of high-pressure natural gas feeder lines, subject to a cap.

Other—Questar Gas flows ratepayers' share of its capacity release revenue to customers via its semi-annual gas-cost pass-through proceedings.

Vermont

Decoupling—An alternative regulation plan in place for Green Mountain Power has somewhat obviated the need for revenue decoupling mechanisms, as the plan allows for annual rate adjustments based on the company's forecast of sales and costs, and contains earnings-sharing provisions that minimize losses if sales fall significantly from forecast. The plan is to be in place through Dec. 31, 2017.

Virginia

Electric Fuel/Purchased Power—Energy and capacity charges for "economy" purchases are included in the electric fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor; but capacity charges are recovered through base rates.

Decoupling — A Weather Normalization Adjustment, or WNA, Rider is in place for Virginia Natural Gas, or VNG, and Washington Gas Light, or WGL. Similar programs are in place for Roanoke Gas, Southwestern Virginia Gas, Atmos Energy and Columbia Gas of Virginia, or CGV.

A separate revenue normalization adjustment mechanism is in place that is designed to mitigate the impact on WGL's, VNG's and CGV's revenues of customers' participation in energy conservation programs.

Environmental Compliance—State statutes permitted the electric utilities to seek SCC approval to begin recovering costs associated with environmental compliance and reliability improvement programs through an Environmental & Reliability Factor, or ERF. Such a mechanism was in place for Appalachian Power, or APCO, but has since expired.

Generic Infrastructure—The SCC may approve annually adjusted riders for the recovery of cost/investments, including a cash return on construction work in progress, associated with utility projects to replace existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth with underground facilities, subject to certain caps. The rider's revenue requirement reflects the rate of return approved in the company's most recent base rate case or biennial review proceeding.

The SCC may also allow a natural gas utility that invests in natural gas facility replacement projects to recover, in the form of a rider, a return on investment, a revenue conversion factor, depreciation, property taxes and carrying costs on over/under recovery of the related costs. Eligible infrastructure replacement is defined as natural gas facility replacement projects that: enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, or natural forces; do not increase revenues by directly connecting the infrastructure replacement to new customers; reduce or have the potential to reduce greenhouse gas emissions; are commenced on or after Jan. 1, 2010; and are not included in the natural gas utility's rate base in its most recent rate case.

Generation Capacity— Legislation enacted in 2007, required the SCC to approve riders for recovery of investment in certain types of generation facilities, including a cash return on construction work in progress and an incremental incentive return on equity premium for certain types of facilities.

Several riders were approved for Virginia Electric and Power, or VEPCO, and APCO under this statute. However, legislation enacted in 2013, limits the availability of ROE adders for new construction commencing after July 2013 to nuclear and offshore-wind generation facilities.

State law authorizes an investor-owned electric utility to recover the costs of purchasing certain solar generation facilities through a rate adjustment clause. On July 5, 2017, APCO filed for SCC approval to establish a solar rate adjustment.

Other—WGL and CGV are permitted to recover carrying charges on storage gas balances and over/under-collected gas costs, hexane costs and commodity-related uncollectibles expense through an adjustment mechanism. APCO and VEPCO have a mechanism in place to recover variations in certain taxes and franchise fees.

Washington

Electric Fuel/Gas Commodity/Purchased Power— Avista Corp.'s Energy Recovery Mechanism, or ERM, includes a graduated sharing of differences from a benchmark level. Power cost adjustment mechanisms are in place for Puget Sound Energy, or PSE, and PacifiCorp that allow for variations in power costs to be apportioned, on a graduated scale, between the company and customers.

Decoupling—Revenue decoupling mechanisms that are in place for PSE's electric and gas operations, are to be in effect through December 2017, when new rates are to become effective in the company's general rate case.

Full decoupling mechanisms in place for Avista's Corp.'s electric and gas operations are to be in place through 2019, incorporate an earnings test and demand-reduction targets, and specify caps on the increases to be implemented under the mechanism.

Cascade Natural Gas', or CNG's decoupling mechanism incorporates an earnings test and a conservation target, and caps on annual increases under the mechanism.

PacifiCorp's decoupling mechanism is to be in place for five years, incorporates an earnings test and demand-reduction targets, and caps increases that may be implemented under the mechanism.

Generic Infrastructure—Pipeline replacement plans are in place for PSE, Avista, CNG, and Northwest Natural Gas, or NNG. The plans are in place through 2017. CNG and PSE utilize riders for the costs associated with their plans. Avista and NNG do not have such a mechanism.

West Virginia

Environmental Compliance/Generation Capacity/Generic Infrastructure—In the past, the PSC has approved temporary riders to provide recognition between rate cases of certain electric generation and infrastructure investments. In June 2016, the PSC authorized Appalachian Power, or APCO, and affiliate Wheeling Power, or WP, to use a "construction surcharge" until their next rate case is decided to allow for recovery of costs associated with certain transmission projects.

Legislation enacted in 2015 allows the PSC to approve expedited cost recovery mechanisms associated with commission-approved multi-year gas infrastructure improvement plans; such treatment has been approved for Mountaineer Gas and Hope Gas.

In 2015, the PSC adopted a settlement authorizing Monongahela Power and Potomac Edison to implement a vegetation management rider that is to be updated twice per year, and is to remain in place for five years. In that same case, the companies also agreed to withdraw their request for an environmental projects surcharge mechanism for costs related to compliance with the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards, as well as related state requirements. However, MonPower/PotEd are to establish a regulatory asset for compliance-related investments made between Jan. 1, 2016 and Dec. 31, 2017. Recovery of the regulatory asset will be subject to a prudence review. APCO/WP also utilize a rider for vegetation management related costs.

Other—The utilities have mechanisms in place to recover variations in certain taxes and franchise fees.

Wisconsin

Electric Fuel/Gas Commodity/Purchased Power—Under the PSC's electric fuel rules, which apply to the state's five largest investor-owned utilities, each utility forecasts monthly and annual fuel and purchased power costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts, and the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. An electric utility is permitted to defer any fuel costs that are outside of its annual, symmetrical variance range for subsequent recovery or refund. However, the utility is prohibited from recovering deferrals if the company is found to be earning in excess of its authorized equity return.

Generation Capacity/Generic Infrastructure/Other—At times, the PSC has authorized the utilities to file a limited issue reopener, or LIR, of a previously completed base rate case instead of a full rate case. The LIR provides for recognition of certain specified investments and/or expenses, and does not involve the re-determination of rate of return.

Other—All of the utilities have a mechanism in place to recover variations in certain taxes and franchise fees.

Wyoming

Decoupling—Black Hills Gas Distribution has a partial decoupling mechanism in place for small and medium general service class distribution customers. The mechanism does not address revenue variations due to weather. Cheyenne Light Fuel and Power's, or CLF&Ps, demand side management, or DSM, mechanisms for its electric and gas operations include provide for the recovery of "lost margins" associated with customer participation in the DSM programs.

Renewables Expense/Environmental Compliance—Optional renewable energy riders are in place for CLF&P, MDU Resources and PacifiCorp. PacifiCorp operates under an adjustment mechanism that is designed to recover from or refund to ratepayers 100% of the difference between actual renewable energy and SO_2 emissions allowance credit revenue levels and the levels reflected in base rates.

Other—Through an incentive provision of its fuel clause, CLF&P allocates a portion of off-system sales margins to ratepayers.

Equity Ratio Adjustment Analysis

Adjusted Common Equity

For Rate Cases in Arkansas, Florida, Indiana and Michigan where Zero Cost Items have been included in the Capital Structure.

State	Company	Parent Company Ticker	Case Identification	Service	Year Ordered	Return on Equity (%)	Common Equity /Total Cap (%)	Type of Capital	Percent of Capitalization	Cost Rate	Adjusted Common Equity	Notes:
Arkansas	Oklahoma Gas and Electric Co.	OGE	D-10-067-U	Electric	2011	9.50	36.38	Long-Term Debt	33.76%	5.68%	49.61%	• All Capital with a 0 Cost Rate was excluded. (Accumulated Deferred Income Taxes, Post-1970 ADITC (Long-Term Debt), Post-1970 ADITC (Short-Term Debt), Post-1970 ADITC (Equity) and Current, Accrued, and Other Liabilities)
								Short-Term Debt	2.11%	0.76%		
								Customer Deposits	0.98%	1.47%		
								Accumulated Deferred Income Taxes	22.85%	0.00%		
								Post-1970 ADITC (Long-Term Debt)	0.01%	5.68%		
								Post-1970 ADITC (Short-Term Debt)	0.00%	0.76%		
								Post-1970 ADITC (Equity)	0.02%	9.50%		
								Current, Accrued, and Other Liabilities	3.79%	0.00%		
								Other Capital Items	0.10%	8.53%		
								Common Equity	36.38%	9.50%		
								Total	100.00%			
Arkansas	Southwestern Electric Power Co	AEP	D-09-008-U	Electric	2009	10.25	33.99	Long-Term Debt	39.91%	6.02%	43.18%	• All Capital with a 0 Cost Rate was excluded. (Accum. Deferred Income Tax, Post-1970 ADITC - L/T Debt, Post-1970 ADITC - Preferred Stock, Post-1970 ADITC - Common Equity and Current, Accrued, and Other Liabilities)
								Preferred Stock	0.12%	4.87%		
								Accumulated Deferred Income Taxes	10.93%	0.00%		
								Post-1970 ADITC - L/T Debt	0.23%	6.02%		
								Post-1970 ADITC - Preferred Stock	0.00%	4.87%		
								Post-1970 ADITC - Common Equity	0.19%	10.25%		
								Customer Deposits	1.01%	3.60%		
								Current, Accrued, and Other Liabilities	9.91%	0.00%		
								Other Capital Items	3.71%	1.39%		
								Common Equity	33.99%	10.25%		
								Total	100.00%			

Adjusted Common Equity

For Rate Cases in Arkansas, Florida, Indiana and Michigan where Zero Cost Items have been included in the Capital Structure.

State	Company	Parent Company Ticker	Case Identification	Service	Year Ordered	Return on Equity (%)	Common Equity /Total Cap (%)	Type of Capital	Percent of Capitalization	Cost Rate	Adjusted Common Equity	Notes:
Florida	Duke Energy Florida Inc.	DUK	D-090079-EI	Electric	2010	10.50	46.74	Long-Term Debt	45.17%	6.18%	49.09%	• All Capital with a 0 Cost Rate was excluded. (Customer Deposits-Inactive, Deferred Income Taxes, Tax Credits, and FAS 109 Deferred Income Tax-Net)
								Short-Term Debt	0.66%	3.72%		
								Preferred Stock	0.34%	4.51%		
								Customer Deposits-Active	2.31%	5.95%		
								Customer Deposits-Inactive	0.02%	0.00%		
								Deferred Income Taxes	6.67%	0.00%		
								FAS 109 Deferred Income Tax-Net	-1.97%	0.00%		
								Tax Credits	0.06%	8.36%		
								Common Equity	46.74%	10.50%		
								Total	100.00%			
Florida	Gulf Power Co.	SO	D-110138-EI	Electric	2012	10.25	38.50	Long-Term Debt	39.29%	5.26%	45.57%	• All Capital with a 0 Cost Rate was excluded. (Deferred Income Taxes and Investment Tax Credits)
								Short-Term Debt	1.07%	0.13%		
								Preferred Stock	4.36%	6.39%		
								Customer Deposits	1.27%	6.00%		
								Deferred Income Taxes	15.34%	0.00%		
								Investment Tax Credits	0.17%	7.66%		
								Common Equity	38.50%	10.25%		
								Total	100.00%			
Indiana	Duke Energy Indiana Inc.	DUK	Ca-42359	Electric	2004	10.50	44.44	Long-Term Debt	38.87%	6.37%	52.44%	• All Capital with a 0 Cost Rate was excluded. (Deferred Income Tax, Investment Tax Credits-1970 & Earlier, and Investment Tax Credits-1971 & Later)
								Preferred Stock	1.17%	6.11%		
								Deferred Income Tax	14.39%	0.00%		
								Investment Tax Credits-1970 & Earlier	0.01%	0.00%		
								Investment Tax Credits-1971 & Later	0.85%	8.53%		
								Customer Deposits	0.27%	6.00%		
								Common Equity	44.44%	10.50%		
								Total	100.00%			

Adjusted Common Equity

For Rate Cases in Arkansas, Florida, Indiana and Michigan where Zero Cost Items have been included in the Capital Structure.

State	Company	Parent Company Ticker	Case Identification	Service	Year Ordered	Return on Equity (%)	Common Equity /Total Cap (%)	Type of Capital	Percent of Capitalization	Cost Rate	Adjusted Common Equity	Notes:
Indiana	Indiana Michigan Power Co.	AEP	Ca-44075	Electric	2013	10.20	42.67	Long-Term Debt	38.74%	6.33%	51.83%	• All Capital with a 0 Cost Rate was excluded. (Accumulated Deferred JDITC and Accumulated Deferred FIT)
								Preferred Stock	0.20%	4.58%		
								Accumulated Deferred JDITC	1.36%	8.35%		
								Accumulated Deferred FIT	16.32%	0.00%		
								Customer Deposits	0.71%	6.00%		
								Common Equity	42.67%	10.20%		
								Total	100.00%			
Michigan	Indiana Michigan Power Co.	AEP	C-U-16801	Electric	2012	10.20	42.07				50.92%	• Settlement agreement (Pg. 2) approved by Commission states that "As based on a 2012 test year, I&M's rates should be adjusted to provide an annual revenue increase of $14,644,416 for effective service rendered beginning with the next full cycle of billings following the issuance of a Commission order approving this Settlement Agreement. The factors used to develop the annual revenue increase are set forth in Exhibit A. The authorized rate on Common Equity is 10.2%, which results in a calculated overall rate of return of 6.84%. The authorized overall rate of return is based on an annual average permanent capital common equity ratio of 50.92%. "

Storm Cost Recovery Sources

General Information

Contact Information	10 Franklin Square New Britain, CT 06051 (860) 827-1553
	http://www.ct.gov/pura
Number of Commissioners	3 of 3
Selection Method	Commissioners: Gubernatorial appointment, General Assembly confirmation Chairperson: Elected by fellow Commissioners
Term of Office	Commissioners: 4 years Chairperson: 1 years
Chairperson of Commission	Katie Dykes
Deputy Chairperson of Commission	John W. Betkoski III
Governor	Dannel P. Malloy (D)
Service Regulated	Cable television companies, Electric utilities, Gas utilities, Pipeline companies, Telecommunications utilities, Water utilities
Commission Ranking	Below Average/2 (11/15/2017)
Commmission Budget	$11.50 million
Commissioner Salaries	Commissioners: $128,500 - $175,200 Chairperson: $138,800 - $189,500
Size of Commission Staff	65
Company Name, Abbreviated	Connecticut Public Utilities Regulatory Authority's Rate Case History
Research Notes	RRA Articles
RRA Contact	Lisa Fontanella

Commissioners

Person's Name	***Party Abbreviation***	***Date Role Began***	***Term Ends***
Katie Dykes Chairman	D	10/2016	06/2020
John W. Betkoski III Vice Chairman	D	07/1997	06/2019
Michael Caron	R	07/2012	06/2017

RRA Ranking History

Date of Ranking Change	***Commission Ranking***
11/15/2017	Below Average / 2
5/11/2017	Below Average / 3
10/22/2013	Below Average / 2
7/16/2009	Below Average / 3
3/23/2009	Below Average / 2

Date of Ranking Change	Commission Ranking
4/1/2008	Below Average / 1
10/29/2002	Average / 3
5/2/1997	Average / 2
7/16/1993	Average / 1
4/4/1991	Above Average / 3
7/7/1986	Above Average / 2
4/4/1983	Above Average / 3
7/2/1982	Average / 1

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

Structure — The PURA is part of the Department of Energy and Environmental Protection, or DEEP. The DEEP is responsible for energy-related planning and oversight, and is headed by a commissioner, who is appointed by the governor. The current DEEP commissioner is Robert Klee.

Utility commissioners, chairman, and vice chairman selection — Legislation enacted in 2013, renamed the three members of the PURA "utility commissioners" rather than directors. No more than two commissioners may be from the same political party. An appointee may serve subject to confirmation if the General Assembly is not in session at the time of appointment. Any commissioner appointed after 2013 must have a background in at least one of the following fields: economics; engineering; law; accounting; finance; utility regulation; public or government administration; consumer advocacy; business management; or, environmental management. At least one of the three utility commissioners must have experience in consumer advocacy issues. The chairman and vice chairman are elected by fellow commissioners each June; terms run from July 1 through the following June 30.

Commission membership — Commissioner Michael Caron continues to serve beyond the end of a term that expired in June 2017.

Gubernatorial election — Gov. Dannel Malloy is not seeking a third term. At this time, there are a dozen republican and democratic candidates vying for the position with no clear frontrunners.

Services regulated — In addition to the economic regulation of electric, gas, telephone, water, and sewer utilities and cable television companies, the PURA has authority over the issuance of securities by jurisdictional utilities, with the exception of cable television companies.

Staff contact — Michael Coyle, Special Enforcement and Consumer Affairs, (860) 424-3110 (Section updated 2/8/18)

Accounting

By law, the DPUC is required to conduct a management audit of each of the state's energy utilities every six years that includes a review of all functions of the utility. (Section updated 6/7/10)

RRA Evaluation

Connecticut regulation is relatively restrictive from an investor perspective. Authorized returns on equity have been well below the average of returns accorded energy utilities nationwide at the time established. In addition, the Connecticut Public Utilities Regulatory Authority, or PURA, has periodically adopted ROE penalties, the most recent of which was imposed for poor storm-related performance a few years ago. Earnings sharing mechanisms are in place for all of the state's electric utilities that require the companies share with ratepayers earnings in excess of the authorized ROE, but there is no sharing of under-earnings. Under Connecticut law, an earnings review must be initiated when a company earns in excess of its authorized return by at least 100 basis points for six consecutive months, and several such reviews have occurred in recent years. There is no automatic mechanism for addressing under-earnings. In addition, under existing statutes, the PURA must conduct a financial and operational review of each major utility at least every four years and a managerial audit of the utility's operations every six years. In recent years the PURA has approved two major energy mergers following the adoption of settlements that provided for rate credits and base rate freezes. More, recently, the PURA approved Eversource Energy's acquisition of Aquarion Water, without onerous conditions. However, a handful of somewhat more constructive policies have been implemented following legislation, including adoption of decoupling mechanisms for most of the state's utilities and the utilization of gas capital-cost-recovery mechanisms. In addition, although not favored by the in-state utilities, legislation was enacted in 2017 that is viewed as supportive of legacy nuclear generation in the state; this move was seen as constructive by investors of Dominion Energy, which owns the Millstone nuclear plant. RRA accords Connecticut regulation a Below Average/2 ranking. (Section updated 2/8/18)

Commission Staff

The PURA employs approximately 65 persons. Staff members are selected through the state's Merit System. (Section updated 2/8/18)

Consumer Interest

Represented by the Office of Consumer Counsel, or OCC. The OCC is funded by an assessment against the revenues of the utilities. The Consumer Counsel is appointed by the governor for a five-year term. The current Consumer Counsel is Elin Swanson Katz, who is serving a term that extends through June 30, 2021. In addition, a portion of the PURA staff may be assigned to participate as a party in each major proceeding. The Attorney General, or AG, who is selected through direct voter elections, is also an active participant. The current AG is George Jepsen, a Democrat, who is serving a term that ends in January 2019. Jepsen has announced that he will not seek re-election to that position. The Department of Energy and Environmental Protection may participate as a party in PURA proceedings. (Section updated 2/8/18)

Rate Case Timing/Interim Procedures

Utilities are required to submit a Notice of Intent at least 30 days, but not more than 60 days, prior to the filing of an application to change rates. The PURA may extend the normal 150-day review period to 180 days upon providing notification to all the parties. If the PURA fails to issue an order by the end of the review period, a requested increase may be implemented subject to refund.

By law, if a major energy utility has not had a general rate case in the last four years, a financial and operational review must be conducted by the PURA. In addition, a managerial audit of each major utility is required at least every six years.

Interim rate increases have rarely been sought or authorized for major utilities; a utility must demonstrate that a financial emergency exists. Under state law, interim rate decreases may be ordered if a utility has earned an ROE exceeding its authorized return by at least 100 basis points for six consecutive months, or there is a finding that a utility is collecting rates that are more than "just, reasonable, and adequate." Under the law, the utility is "required to demonstrate to the satisfaction of the Authority that earning such a return on equity or collecting rates which are more than just, reasonable and adequate is directly beneficial to its customers." The PURA has determined that the state law does not limit its authority to approve a sharing mechanism in the event of an overearnings situation. (Section updated 2/8/18)

Rate Base and Test Period

The PURA has generally relied on a year-end original-cost rate base for a historical test period, with adjustments to rate base, revenues, expenses and capitalization to reflect conditions at the midpoint of the rate year. By law, the PURA is prohibited from allowing a cash return on construction work in progress. (Section updated 2/8/18)

Return on Equity

Over the past several years, authorized ROEs have been well below prevailing industry averages when established, and the PURA has in certain instances adopted performance-related penalties further lowering the authorized ROE. In addition, state law requires an earnings review to be initiated when a company earns in excess of its authorized return by at least 100 basis points for six consecutive months. The law requires a utility "to demonstrate to the satisfaction of the authority that earning such a return on equity or collecting rates which are more than just, reasonable and adequate is directly beneficial to its customers."

All of the state's energy utilities are subject to asymmetrical earnings sharing mechanisms that provide for sharing of earnings above an ROE benchmark but provide no sharing of under-earnings. For further details, see the Alternative regulation section.

United Illuminating, or UI, a subsidiary of AVANGRID is authorized a 9.1% ROE, established in December 2016. In 2014, the PURA had authorized Connecticut Light & Power, or CL&P, a 9.17% ROE, with a 15-basis-point equity return penalty to be in place during 2015. The penalty was designed to recognize poor performance in preparing for, and responding to outages caused by storms. CL&P is a subsidiary of Eversource Energy.

On Dec. 13, 2017, the PURA adopted a 9.25% ROE for Southern Connecticut Gas, or SCG, following a settlement. SCG is a subsidiary of Connecticut Energy Corporation, which is a subsidiary of AVANGRID.

In 2015, the PURA adopted a settlement in an earnings investigation for Yankee Gas Services that extended the 8.83% ROE established in 2011. However, an earnings sharing mechanism would be triggered if the company's actual ROE were to exceed 9.5% for more than 12 months. Yankee Gas is a subsidiary of Yankee Energy System, which is a subsidiary of Eversource Energy.

Connecticut Natural Gas, or CNG, is authorized a 9.18% ROE, established in 2014. CNG is a subsidiary of CTG Resources, which is a subsidiary of AVANGRID.

In accordance with state law, in 2008 the PURA authorized GenConn Energy and PSEG New Haven LLC to construct two peaking generation facilities and required CL&P and UI to enter into cost-of-service contracts with these projects. These projects are accorded an ROE that consists of an index, made up of the average of CL&P's and UI's authorized ROEs established in distribution rate cases, plus an adder. See the Alternative regulation and Integrated resource planning sections for further details. For 2018, the PURA set GenConn Energy's ROE at 9.81%, and for the PSEG New Haven station, the PURA set the ROE at 10.31%. (Section updated 2/8/18)

Alternative Regulation

By law, the PURA may approve performance-based-regulation, or PBR, plans for energy utilities, and the PURA has approved earnings sharing mechanisms, or ESMs, in several instances. While the existence of an ESM does not negate the need for a four-year rate review, a periodic review by the PURA of a utility operating under a qualified PBR plan may serve in lieu of the otherwise-mandated four-year rate review. See the Rate case timing/interim procedures section for further details.

ESMs — All of the state's energy utilities have an ESM in place. The state's overearnings statute, which mandates the PURA to review the need for an interim rate decrease when a company "has, for six consecutive months, earned a return on equity which exceeds the return authorized by the Authority by at least one percentage point," continues to apply despite the utilization of an ESM. However, under the law in the event that an interim review is triggered, the statute allows the PURA to permit the company's rates to continue if "it determines that "earning such a return on equity…is directly beneficial to its customers."

For Connecticut Light & Power, or CL&P, earnings above a 9.17% ROE are to be shared equally with ratepayers. A 9.02% ROE was in place for 2015 that reflected a 15-basis-point penalty for poor performance in preparing for, and restoring service after certain storms. The ratepayers' portion of any shared earnings is returned through a bill credit.

United Illuminating, or UI, retains 50% of earnings in excess of its authorized ROE, currently 9.1%. The ratepayers' portion of any shared earnings is first used towards any storm regulatory asset, if one exists at the time, and then any remainder flows to customers through a bill credit. The ESM was adopted for UI in December 2016, as part of a multi-year rate plan that is in effect from Jan. 1, 2017 through Dec. 31, 2019.

For Connecticut Natural Gas, earnings in excess of a 9.18% ROE are to be shared equally with ratepayers, through a bill credit. The ESM is to remain in place until the company's next rate case.

For Southern Connecticut Gas, or SCG, earnings in excess of a 9.25% ROE are to be shared equally with ratepayers. Any amounts due ratepayers are first to be used to reduce various regulatory assets associated with certain unamortized environmental remediation costs. Remaining amounts are to be credited to ratepayers. The ESM was adopted for SCG as part of a multi-year rate plan that is to be in place from Jan. 1, 2018, through Dec. 31, 2020 period.

For Yankee Gas, an ESM has been in effect since April 1, 2015, under which earnings in excess of a 9.5% ROE are to be shared equally with customers. The ESM is to remain in place until a decision is issued in the company's next base rate case. The company agreed to forgo implementing a base distribution rate increase prior to Jan. 1, 2017.

Other alternative regulation provisions —CL&P and UI are authorized earning incentives on conservation and load management initiatives, if certain energy-savings and demand-reduction targets are met.

The state's comprehensive energy strategy released in 2013 recommended that the PURA consider the adoption of a performance-based rate of return paradigm based on defined performance targets tied to storm response, efficiency goals, grid reliability and electricity costs. No further action has been taken. For further details, see the Integrated resource planning section. (Section updated 2/8/18)

Court Actions

PURA decisions may be appealed to the State Superior Court, then to the Appellate Court, and ultimately to the Connecticut Supreme Court. Supreme, Appellate and Superior Court judges are appointed to eight-year terms by the General Assembly from nominations submitted by the governor. There have been no major utility-related issues decided by courts in recent years. (Section updated 2/8/18)

Legislation

The bicameral Connecticut General Assembly meets annually beginning in January for five months in odd-numbered years, and beginning in February for three months in even-numbered years. The 36-member Senate currently has 18 Democrats and 18 Republicans, and the 151-member House of Representatives has 79 Democrats and 72 Republicans. Utility matters have frequently been before the General Assembly and several utility-related measures were enacted in 2017.

On June 27, 2017, Gov. Malloy signed House Bill, or HB, 7036, allowing electric distribution companies to build, own or operate up to 30 MW of new fuel cell generation, or enter into purchased power contracts with owners of such technology. In addition, the law modifies a provision of the state's renewable portfolio standard, and now requires electric distribution companies to purchase 4%, rather than 3% of their power from either Class I or Class II sources beginning in 2018. See the Renewable energy section for further details. HB 7036 also requires that, effective Jan. 1, 2019, a ratepayer impact statement be included in all bills prepared by the General Assembly.

On June 30, 2017, Gov. Malloy signed HB 7104, which rescinds the ability of electric suppliers and electric distribution companies to make up renewable energy portfolio deficiencies for any given year during the first quarter of the succeeding calendar year.

On July 25, 2017, Gov. Malloy signed an executive order calling for the Connecticut Department of Energy and Environmental Protection, or DEEP, and the PURA to conduct an assessment to determine the economic viability of the Millstone nuclear facility, as well as the role of nuclear generation and other various means to meet the state's "interim and long-term carbon and other emissions targets, at the least cost and with the greatest net benefit to Connecticut ratepayers, while maintaining the reliability of [the] electric grid." The results of the assessment were submitted to the legislature on Feb. 1, 2018, and are detailed below.

In special session, on Oct. 31, 2017, Gov. Malloy signed into law Senate Bill, or SB, 1501, which permits Millstone to compete with other zero-carbon electricity generating resources, if the DEEP and the PURA deem it to be in the public interest. Dominion Energy Inc. owns 100% of Millstone unit 2 and 93.47% of Millstone unit 3, which are licensed to operate through 2035 and 2045, respectively. SB 1501 requires the DEEP and the PURA to conduct an appraisal of nuclear power generating facilities and determine whether to conduct a solicitation process for nuclear generating facilities. SB 1501 requires a determination that any agreements entered into be in the ratepayers' best interest.

In accordance with the directives contained in the executive order and SB 1501, a final assessment was submitted to the legislature on Feb. 1, 2018 that recommends that Millstone be permitted to compete in the state's renewable energy procurement, "with certain conditions to ensure that the state's ratepayers are protected from paying above-market costs for resources that are not verified to be at risk of retirement." The legislature is required, under the law, to review the assessment by March 1, 2018, and no later than May 1, 2018. A request for proposals for a competitive auction process would commence thereafter. See the Integrated resource planning section for further details.

Following a wind and rain storm that impacted the Northeast in October 2017, the General Assembly's Energy and Technology Committee held a hearing to review the storm restoration response of Connecticut Light & Power and United Illuminating. No action has been taken to date.

The 2018 legislature session is to commence on Feb. 7. (Section updated 2/8/18)

Corporate Governance

By law, the PURA is required to conduct a management audit of each of the state's energy utilities every six years that includes a review of all functions of the utility.

The PURA has authority over securities issuances by utilities' and affiliate transactions. Corporate governance issues have occasionally arisen in the context of financing orders.

The PURA also has authority over mergers and acquisitions involving the utilities it regulates, and has implemented ringfencing-type measures in the context of such proceedings. For further details, see the Merger activity section. (Section updated 2/8/18)

Merger Activity

State law requires the PURA to review a proposed merger only when the transaction results in a change of control over Connecticut public service companies. When reviewing proposed mergers, the PURA considers: (1) the financial, technological and managerial suitability and responsibility of the applicant; and, (2) the ability of the applicant to provide safe, adequate and reliable service to the public. Under the statute, the "burden of proving" that a "transfer of assets or franchise is in the public interest shall be on the public service company." In addition, the law indicates that the state of Connecticut is to promote local control of the state's public service companies. Under the law, the PURA must issue a decision within 120 days after an application is filed, unless an applicant agrees to an extension of time.

In 1999, the PURA approved the merger of Northeast Utilities and Yankee Energy System, the parent of Yankee Gas Services, or YGS. The merger closed in 2000, and YGS was prohibited from recovering the acquisition premium and associated merger-related transaction costs from ratepayers. In 2000, the PURA conditionally approved the proposed merger of Northeast Utilities, parent of both YGS and Connecticut Light & Power, or CL&P, and Consolidated Edison. Although the merger was never consummated, the PURA would have required CL&P, at a minimum, to maintain a capital structure that included at least 38% common equity, and YGS to maintain a capital structure with at least 43% common equity. In addition, the PURA would have required that neither CL&P nor YGS pay more than 100% of their respective net income as dividends to Northeast Utilities in any one year.

In 1999, the PURA conditionally approved the merger of Southern Connecticut Gas, or SCG, parent Connecticut Energy Corporation, or CEC, and Energy East. The merger was completed in 2000, and CEC became a subsidiary of Energy East. As a condition of the approval, the PURA was to have access to the books and records of Energy East and its affiliates in order to audit all costs and revenues ultimately allocated to SCG.

In 2000, the PURA approved the proposed merger of Energy East and Connecticut Natural Gas, or CNG parent CTG Resources, or CTG. The merger was completed in September 2000, and CTG became a subsidiary of Energy East. CNG remains a utility subsidiary of CTG and continues to operate under that name. As a condition of approving the proposed merger, the PURA required the companies to adopt specific procedures for affiliate transactions designed to ensure that they occur at "arms length."

In 2007, the PURA conditionally approved Iberdrola's acquisition of Energy East. The transaction was completed in 2008, at which time Energy East became a subsidiary of Iberdrola and was renamed Iberdrola USA. Ibedrola became the ultimate parent of CTG and CEC; however, CTG and CEC have since been acquired by UIL Holdings. Under the PURA's conditions: (1) Iberdrola was prohibited from divesting, selling or spinning off, or combining CNG and SCG without prior PURA approval; (2) Any goodwill or other acquisition-related expenses that may have resulted from the transaction were not recoverable from ratepayers of CNG or SCG; (3) All affiliate transactions involving gas commodity procurement were subject to review by the PURA; (4) CNG and SCG were prohibited from recording any valuation adjustments resulting from this merger; and, (5) Iberdrola was precluded from removing CTG's, CEC's, CNG's and SCG's original books and records from Connecticut without prior PURA approval.

In 2010, the PURA approved UIL Holdings' acquisition from Iberdrola USA, formerly Energy East Corporation, of CEC and CTG, and their respective utility subsidiaries SCG and CNG. The PURA's order did not include specific conditions. The acquisition was completed in November 2010. CEC and CTG are now subsidiaries of UIL Holdings.

In 2012, the PURA approved the merger of Northeast Utilities and NSTAR following a settlement. The approved settlement provided for a one-time rate credit of $25 million for customers of NU subsidiary CL&P, with electric distribution rates to be frozen until Dec. 1, 2014. CL&P was required to file a rate case to establish new rates, including an earnings-sharing mechanism, to become effective immediately following the conclusion of the rate-freeze period; the case concluded in 2014. Initially, CL&P was to file a second rate case within three years following the initial base-rate-freeze period, with new rates to become effective no later than Dec. 1, 2017. However, on April 20, 2017, the PURA approved a request from CL&P, the Office of Consumer Counsel, and the attorney general to push back the deadline for implementing rates to July 1, 2018; a rate case is pending. In accordance with the merger agreement, in 2013, the PURA approved a $300 million multi-year plan for investment in distribution system "resiliency" measures as part of the company's ongoing effort to improve system performance. CL&P is to improve service quality performance, and penalties can be imposed by the PURA for failure to at least maintain service quality performance consistent with historical averages over the last 10 years. In addition, CL&P agreed to forgo recovery of $40 million of the approximately $260 million of costs incurred as a result of Tropical Storm Irene and a 2011 snow storm. For a period of at least seven years, NU is to maintain: a principal Board and Executive offices, functions, and staff in Hartford; the headquarters of CL&P, Yankee Gas, the transmission business, and NU Call Center operations in Connecticut; and, charitable donations and civic commitments to Connecticut at levels consistent with those that occurred five years prior to the merger. In addition, NU and NSTAR must preserve the aggregate number of line workers in both Connecticut and Massachusetts. The merger closed in 2012, and after a rebranding effort that commenced in 2015, the company is now known as Eversource Energy.

In 2015, the PURA approved Iberdrola USA's, or IUSA's, proposed acquisition of UIL Holdings Corp., following a settlement. In December 2015, Iberdrola USA and UIL merged to form AVANGRID. The approved settlement provided for rate credits totaling $20 million to customers of United Illuminating, or UI, Southern Connecticut Gas, or SCG, and Connecticut Natural Gas, or CNG, within the first year following the closing. Also, the companies are to provide $12.5 million in additional rate credits to customers of CNG over the 10 years 2018 through 2027. For SCG, the applicants are to provide $7.5 million in additional rate credits over the 10 years 2018 through 2027 and increase SCG's spending on the replacement of cast iron/bare steel pipe over a three-year period, without seeking rate recovery for the increased spending until the next SCG distribution rate case; estimated ratepayer benefit of $1.6 million. The companies were subject to base rate freezes; for UI until at least Jan. 1, 2017, and for CNG and SCG until at least Jan. 1, 2018. In addition, the companies were to provide $6 million to the Connecticut Department of Energy and Environmental Protection to fund energy efficiency, renewable generation, storage, alternative transportation, electric vehicles and other clean technologies.

In addition, the companies are to: provide $1 million for disaster relief for Connecticut residents; maintain annual charitable donation levels for at least the next four years; and, hire 150 people in Connecticut over the next three years. UI is to expend $30 million to investigate and remediate certain environmental conditions at the English Station site. The companies are to improve customer service metrics over the long-term and maintain high levels of safety and reliability. The companies are to create a special purpose entity, or SPE, comprised of four directors appointed by IUSA, one of which is to be an independent director. The SPE may not commingle its funds or other assets with any other entity. UIL, UI, SCG, CNG and the SPE are to maintain arm's length relationships with each of their affiliates. UIL, the UIL utilities and the SPE are to maintain separate books and records and provide access to such books and records to the PURA. Neither UIL nor the UIL utilities are to incur or assume any debt, including the provision of guarantees or collateral support. The SPE is not to incur or assume any debt unless otherwise approved by the PURA. The UIL utilities are only permitted to participate in money pools where the other participants in such money pools are other regulated utility affiliates in the United States unless otherwise authorized by the Authority.

The UIL utilities are to obtain ratings from two of the three bond rating agencies, and maintain at least an investment grade credit rating for both corporate credit ratings, as well as ratings for long-term debt. No UIL utility is to issue any dividend to its parent if the utility's corporate issuer or senior unsecured credit rating, or its equivalent, falls to the lowest investment grade rating, and there is a negative watch or review downgrade notice for the company by two of the three major credit rating agencies or, alternatively, if such rating falls below investment grade without such notice. If the aforementioned ratings events were to occur, then the UIL utilities are to be precluded from transferring, leasing or lending any moneys, assets, rights or other items of value to any affiliate without first obtaining PURA approval, and the UIL utilities are required to file a plan with the PURA within 60 days explaining the actions that are planned to address and rectify the situation. The UIL utilities are restricted from paying dividends if a minimum common equity ratio is not maintained that is equal to 300 basis points below the equity percentage used to set rates in the utility's most recent distribution rate proceeding, measured using a trailing 13-month average calculated as of the most recent quarter end, exclusive of goodwill.

On Oct. 27, 2017, the PURA approved Eversource Energy's acquisition of Macquarie Utilities Inc. and its subsidiaries, including Aquarion Water, subject to commitments agreed to by the companies during the course of the proceeding. The merger closed on Dec. 4, 2017. The related commitments include: Aquarion Water subsidiary Aquarion Water Company of Connecticut Inc.'s, or AWC-CT's, operational facilities are to continue to be located in Connecticut; Eversource is prohibited from recovering of the acquisition premium from ratepayers; AWC-CT will refrain from proposing rate changes as a result of the transaction; Eversource is to maintain or improve customer service, water-service reliability and water quality levels at AWC-CT; no substantial changes are to be made to current employee levels or existing operational facilities of AWC-CT; Eversource is to provide AWC-CT employees with a total compensation package that is market-based and competitive and is to maintain existing employee policies and plans at AWC-CT that are consistent with policies and plans offered by Eversource; AWC-CT employees are to be provided increased opportunities for growth and advancement; Eversource is to honor collective bargaining agreements; Eversource is to maintain or increase community support and charitable giving efforts in the franchise areas; the combined companies are to maintain a commitment to efficiency, sustainability and environmental stewardship; AWC-CT is to maintain a corporate presence in southwest Connecticut; and, AWC-CT is to develop and propose in its next rate case a low-income program. Eversource is permitted to seek recovery of transaction costs in a future rate case within seven years from the closing date of the transaction. (Section updated 2/8/18)

Electric Regulatory Reform/Industry Restructuring

Legislation — In accordance with state law, full retail competition was phased in by July 1, 2000. Recovery of stranded costs was conditioned upon both non-nuclear and nuclear assets being sold. Investor-owned utilities, or IOUs, were permitted to recover, through a competitive transition assessment, or CTA: above-market generating plants recognized in rates before July 1, 1997; regulatory assets approved before July 1, 1998; and, non-utility generation contracts entered into before Jan. 1, 2000. Regulatory assets and purchased power contracts were permitted to be securitized at the PURA's discretion. For further details, see the Securitization section. The electric distribution companies continue to provide metering, billing and collection services. The IOUs are responsible for providing power to those customers who do not choose a competitive supplier.

Stranded cost recovery — The PURA authorized Connecticut Light & Power, or CL&P, to recover up to $3.6 billion — versus $4.4 billion requested — of stranded costs. A significant portion of CL&P's stranded costs were securitized and were recovered through the CTA, which expired at year-end 2010. The PURA authorized United Illuminating, or UI, to recover up to $801.3 million, of approximately $913 million requested, of stranded costs through a CTA; UI's CTA expired in 2013.

Standard service issues — The state's initial restructuring statutes required incumbent electric utilities to provide standard offer service to all customers who did not choose an alternative supplier. Since Jan. 1, 2007, the utilities have been required to provide: standard service to residential customers and small- and medium-sized business customers — customers with maximum demand less than 500 kWs — who do not receive power from a competitive supplier; and, "last-resort" service to larger customers.

Since 2011, the procurement manager at the Department of Energy and Environmental Protection has been required to, in consultation with each electric distribution company, develop a plan for procuring power and related products via competitive bid for standard and last resort services. The bid process and resulting rates are subject to PURA approval. Standard service generation is procured using a laddered approach in which power is purchased by CL&P and UI in small increments at different time periods to achieve a blended standard service generation rate. (Section updated 2/8/18)

Gas Regulatory Reform/Industry Restructuring

Since 1996, firm transportation-only service has been available for commercial and industrial customers and for residential-customer sites with six or more units supplied through a single meter. Customers opting to purchase gas competitively pay a customer service charge, in addition to a monthly fee per hundred cubic feet of gas moved through local distribution companies', or LDCs', lines. Each LDC is required to offer a package of ancillary services to ensure adequate gas supply in the event the broker does not meet its commitment, or the customer's gas use exceeds contractual purchases. Various options are available to customers taking interruptible service, in order to maximize availability of transportation service and to offer protection against loss of service. (Section updated 2/8/18)

Securitization

The state's electric industry restructuring law provides for securitization of regulatory assets and purchased power agreement, or PPA, related costs. The proceeds of the securitization bonds may not be used to purchase or redeem common stock, thereby limiting the potential associated savings.

Connecticut Light & Power, or CL&P, proposed to securitize $1.45 billion of its stranded costs, and in 2000, the PURA issued a financing order permitting the company to securitize up to $1.5 billion in eligible stranded costs primarily related to PPAs and generation costs. Following an appeal, CL&P issued $1.4 billion of rate reduction bonds. In 1999, the PURA indicated that it would approve securitization of up to $144.4 million related to United Illuminating's, or UI’s, PPAs. UI subsequently indicated that it would not file a securitization request. (Section updated 2/8/18)

Adjustment Clauses

United Illuminating, or UI, and Connecticut Light & Power, or CL&P, continue to provide electric supply service to customers who do not select an alternative generation supplier, and the power to meet these requirements is obtained via competitive bids. UI and CL&P are permitted to recover their full costs of soliciting generation service to those customers who do not choose an alternative supplier. Such costs are flowed through to ratepayers outside of a general rate case.

Mechanisms are in place for CL&P and UI that provide for semi-annual rate adjustments to reflect Federal Energy Regulatory Commission-approved transmission costs.

Electric and gas utilities in Connecticut utilize a conservation adjustment mechanism, or CAM, to recover expenses incurred in accordance with their annual conservation and load management plans, as well as recovery of any lost revenues associated with implementation of energy conservation measures. A reconciliation of CAM revenue to expenses is performed annually, with any difference to be recovered from or refunded to customers, with carrying charges, the following year.

State law enacted in 2013, mandates the adoption of full decoupling mechanisms for the state's electric and gas utilities. The law states that the PURA must consider the impact of decoupling on the electric or gas utility's return on equity and make the necessary adjustments.

The PURA adopted a full revenue decoupling mechanism for UI in 2013, for CL&P in 2014, for Connecticut Natural Gas in 2014, and for Southern Connecticut Gas, or SCG, on Dec. 13, 2017. Yankee Gas is not operating under a decoupling mechanism.

Purchased gas costs that differ from the levels reflected in base rates are reflected in purchased gas adjustments, or PGAs, which are modified monthly. Over- or under-recoveries are refunded to, or collected from, customers during a subsequent 12 month period. A local gas distribution company may suspend or discontinue its PGA clause if approved by the PURA. As part of an earnings investigation settlement adopted by the PURA, Yankee Gas has agreed to forgo the implementation of a decoupling mechanism prior to new base rates going into effect; a base rate freeze is in effect until Jan. 1, 2017.

In 2014, the PURA adopted a Distribution Integrity Management Program, or DIMP, mechanism for CNG that allows for recovery of the costs associated with main replacement activity between rate cases. As part of an earnings investigation settlement adopted by the PURA, Yankee Gas has agreed to forego the implementation of a DIMP prior to new base rates going into effect. On Dec. 13, 2017, the PURA adopted a DIMP mechanism for SCG.

In accordance with state law and the associated comprehensive energy strategy, the PURA in 2013 established a system expansion reconciliation mechanism that permits the gas companies to reconcile gas-expansion-related revenue annually between rate cases. See the Integrated resource planning section for further details. (Section updated 2/8/18)

Integrated Resource Planning

Integrated Resource Planning — With the implementation of electric industry restructuring and the associated generation divestiture, traditional integrated resource planning, or IRP, rules were largely abandoned. Energy-related planning and oversight is now conducted by the Department of Energy and Environmental Protection, or DEEP. State law requires the DEEP to prepare an IRP, every two years, to assess future demand and develop a plan for the procurement of energy resources, including generating facilities and energy efficiency programs that would "lower the cost of electricity."

Specifically, the law requires that energy resource needs “shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable basis with non-demand-side resources.”

State statutes require natural gas distribution utilities to file biennial five-year forecasts of natural gas demand and supply with the PURA.

Comprehensive Energy Strategy — In addition to an IRP, state law requires the DEEP to periodically prepare a comprehensive energy strategy, or CES, for the state's energy needs. The strategy draws upon conclusions in the IRP. In 2013, Gov. Malloy released the state's first CES, which included recommendations in five areas: energy efficiency; electricity supply, including renewable power; industrial energy needs; natural gas; and, transportation. Specifically, the CES recommended that the PURA implement full, permanent decoupling for the state's energy utilities. In addition, the CES stated that "performance-based benefits, tied to achievement of the greatest efficiency for the least cost, should therefore be expanded in addition to decoupling, so as to fully incentivize the utilities to implement efficiency programs in the most cost-effective way." The CES recommended that the PURA consider the adoption of a performance-based rate of return paradigm based on defined performance targets tied to storm response, efficiency goals, grid reliability and electricity costs.

The 2013 CES also provided support for the expanded use of natural gas in Connecticut through infrastructure expansion. Many elements of the CES were codified by legislation, House Bill 6360, that was enacted in 2013.

Also in 2013, the PURA issued a final order approving a joint infrastructure expansion plan for the state's local gas distribution companies. The plan specified a goal of 280,000 new natural gas customers by 2023.

In addition, the PURA's 2013 order: modified the way customer contribution-in-aid-of-construction balances are calculated to include a new hurdle rate model utilizing a 25-year payback period; eliminated the requirement to perform a hurdle-rate test for customers located less than 150 feet from an existing main; and, provided for a "portfolio view" approach to modeling projects in a common geographic location. New customers added after Jan. 1, 2014, are charged a monthly premium over current rates to offset incremental costs of expansion. The premium is in lieu of one-time upfront payments for connection costs. On-main customers added after Jan. 1, 2014, are charged a 10-year, 10% system expansion, or SE, premium and off-main customers added after Jan. 1, 2014, are to be charged a 10-year, 30% SE premium. The order required non-firm margin, or NFM, credits, i.e., revenue earned through interruptible and off-system sales, to be used to offset expansion costs for current natural gas customers rather than returned to customers as a bill credit. The PURA's decision directed at least 50% of all NFM credits to offset expansion costs of plant additions. The remaining 50%, or $15 million, whichever is less, is utilized to offset costs of projects deemed to have societal benefits, such as increased employment or local economic development. If the SE premiums and NFM revenue are insufficient to cover ongoing expansion costs, the companies are permitted to utilize a System Expansion Reconciliation, or SER, mechanism to annually true-up gas-expansion-related revenue requirements and actual revenues between rate cases. The SER is to be a separate, stand-alone, line item on customer bills, and is to be incorporated into general rates at the time of a base rate case. The gas companies are required to report expenditures to the PURA to demonstrate that any purchases are in-service, used and useful, in order to recover costs.

On July 26, 2017, a new draft CES was issued, offering recommendations on three sectors: electric power, buildings and transportation. The focus of the draft CES is on increasing the cost effective utilization of renewable resources and de-carbonization. In addition, in the draft CES, the DEEP outlines various grid modernization strategies and calls for the expansion of energy efficiency initiatives. A final CES is expected to be issued in 2018.

Electric merchant generation laws — Legislation enacted in 2007 required the state's electric distribution companies and allowed others to submit proposals for the development of peaking generation in the state. The law required the PURA to approve all proposals unless it finds that a proposal is, or proposals are not, in the interest of ratepayers. In accordance with the law, in 2008, the PURA approved and selected PSEG New Haven LLC and GenConn Energy to build peaking generation units. The law specified that any plan approved by the PURA must: (1) provide for the owner of the peaking generation to be compensated at cost-of-service, plus a reasonable rate of return; and, (2) require that the peaking facility operates in a manner that will reduce overall electricity rates for consumers. PSEG New Haven and GennConn entered into separate contracts for differences with CL&P to recover costs of service. The PURA reviews the cost-of-service of the selected units and updates the project's ROE in annual proceedings. For further details, see the Return on equity section.

Legislation enacted in 2011 permits private developers and electric utilities to build, own, or operate up to an aggregate of 30 MW of statewide generation capacity using Class I renewable energy sources. Each facility is to be between 1 and 5 MW, and the aggregate ownership by a single electric company is to be capped at 10 MW. A competitive procurement was conducted by the DEEP and the PURA approved two 5 MW solar energy projects from private developers and a couple of projects from UI.

Legislation enacted on June 27, 2017, allows electric distribution companies to build, own or operate up to 30 MW of new fuel cell generation, or enter into purchased power contracts with owners of such technology.

Competitive Procurement of Renewable Energy — Various state laws allow the DEEP to seek proposals for the procurement clean energy and renewable resources through long-term contracts. Legislation enacted in 2013 and 2015 authorizes the DEEP to seek proposals for renewable energy generation to address the state's energy infrastructure constraints. Under these two laws, the DEEP has the authority to select clean energy projects to meet up to 15% of the state's electric demand.

Specifically, legislation enacted in 2013, Public Act 13-303, authorizes the DEEP to solicit proposals from Class I and large-scale hydro-power generators and requires Connecticut Light & Power and United Illuminating to enter into 15-year contracts to purchase renewable energy credits from low emission projects up to 2 MW and zero emissions projects up to 1 MW.

Legislation enacted in 2015, Public Act 15-107, allows the DEEP to solicit proposals from providers of energy and energy-related products and services and direct the electric distribution companies to enter into long-term contracts, subject to PURA approval, of up to 20 years. Solicitations are to occur for: demand response measures and smaller renewable energy sources; larger renewable energy sources and hydropower; and, natural gas resources. The DEEP is also permitted to seek proposals for energy storage systems of up to 20 MW of energy. The DEEP is authorized to collaborate with other states in the region on these activities. In addition, the law directs the electric distribution companies to implement cost-effective active demand response programs within their service area and permits the electric distribution companies to recover the cost of such programs through retail rates. Several procurements and contracts have been approved to date under the 2013 and 2015 laws.

Nuclear legislation — Senate Bill 1501 signed into law on Oct. 31, 2017, requires the DEEP and the PURA to conduct an appraisal of nuclear power generating facilities and determine whether to conduct a solicitation process for nuclear generating facilities. Pursuant to the legislation, the DEEP and PURA were required to submit to the General Assembly by Feb. 1, 2018.

As required under the law, the DEEP and PURA submitted a report to the General Assembly on Feb. 1, 2018, calling for the Millstone nuclear plant to compete in the state's renewable energy procurement, "with certain conditions to ensure that the state's ratepayers are protected from paying above-market costs for resources that are not verified to be at risk of retirement." The DEEP and PURA indicate that they would continue to seek regionally integrated mechanisms such as a Dynamic Clean Energy Forward Market or zero emission credits, or ZECs, "that are harmonized with the existing competitive market and will ensure that any investments, if needed, to retain key nuclear generating facilities are shared appropriately with the region that benefits from them." The Connecticut General Assembly is required, under the law, to review the assessment by March 1, 2018 and no later than May 1, 2018. A request for proposals for a competitive auction process could commence thereafter.

Under the law, in order to approve agreement proposal, the DEEP must find it to be in the ratepayers' best interest. If the DEEP determines that any proposals meet such criteria, the state's electric distribution companies, or EDCs, are to enter into agreements to purchase energy, capacity and environmental attributes under the selected proposal.

The total annual energy output of the selected proposals would be limited to no more than 12 million MWhs and the length of the agreements could be at least three and not more than 10 years for eligible nuclear power generation facilities or hydropower and up to 20 years for Class I renewable energy sources and storage. The agreements are subject to PURA approval. The PURA is required to approve PPAs if it determines that they provide for the delivery of adequate and reliable products and service, for which there is a clear need, at just and reasonable prices; they are prudent and cost effective; and the respondent has the technical, financial and managerial capabilities to perform under the agreement. The EDCs are permitted to recover the costs associated with a PPA through a nonbypassable fully reconciling component of ratepayer bills.

Natural gas procurement law — Legislation enacted in 2015 allows the DEEP to solicit proposals for long-term contracts from providers of natural gas pipeline capacity constructed on or after Jan. 1, 2016. As authorized by the law, in June 2016, the DEEP issued a request for procurement for gas resources to be utilized by natural gas generators in the New England region to improve the affordability and reliability of electric supply. Several bids were submitted; however while the DEEP was evaluating the bids, a Massachusetts court issued a ruling that limited the likelihood that the costs of the projects could be shared among the region's ratepayers. The DEEP has indicated that it will consider whether to reissue the proposal in the future. (Section updated 2/8/18)

Renewable Energy

Renewable portfolio standards, or RPS, were initially established in 1998, as part of the state's electric restructuring law; the standards have since undergone several revisions. The law currently specifies separate portfolio standards for energy resources designated as Class I, Class II or Class III.

Class I includes solar, wind, "new sustainable" biomass, wave or tidal power, landfill gas, "run-of-the-river" hydropower installed after July 1, 2003, fuel cells and other qualified low emission advanced renewable energy conversion technologies.

Class II includes trash-to-energy facilities, biomass facilities not included in Class I and run-of-the-river hydropower facilities placed into service prior to July 1, 2003.

Class III resources are defined as "electricity output from combined heat and power systems with an operating efficiency level of no less than 50% that are part of customer-side distributed resources developed at commercial and industrial facilities in Connecticut on or after Jan. 1, 2006, or the electricity savings created at commercial and industrial facilities in Connecticut from conservation and load management programs begun on or after Jan. 1, 2006."

Connecticut's RPS requires electric distribution companies and electric suppliers to get a portion of their energy from renewable sources. The companies were required to generate at least 22.5% of its electric sales from renewable energy by Jan. 1, 2017 — 15.5% Class I, and 3% Class I or Class II and 4% Class III; the requirement increases to 28% by Jan. 1, 2020 —20% Class I, 4% Class I or II and 4% Class III. Since Jan. 1, 2008, the utilities have been permitted to meet their RPS by procuring renewable energy certificates from Class I, Class II and Class III sources under long-term contracts for periods of up to 15 years. Companies can meet the RPS by directly contracting to buy renewable energy or buying renewable energy credits on the regional market. By law, an electric company or supplier that does not meet the RPS must pay an alternative compliance payment of 5.5 cents per kilowatt-hour for the shortfall.

Legislation enacted in 2011, permits private developers and electric utilities to build, own, or operate up to an aggregate of 30 MW of statewide generation capacity using Class I renewable energy sources. Each facility is to be between 1 and 5 MW, and the aggregate ownership by a single electric company is to be capped at 10 MW. A competitive procurement was conducted by the DEEP and two 5 MW solar energy projects from private developers have been selected to date.

Legislation enacted in 2013 authorizes the DEEP to solicit proposals from Class I and large-scale hydro-power generators and requires Connecticut Light & Power and United Illuminating to enter into 15-year contracts to purchase renewable energy credits from low emission projects up to 2 MW and zero emissions projects up to 1 MW. The companies are to enter into contracts each year for six years and the renewable energy credits the companies purchase count towards their RPS obligation.

Increasing the use of renewable resources particularly lower cost grid-scale renewables, and decarbonization were the focus of the state's latest comprehensive energy strategy, or CES, in which a draft was issued by the DEEP on July 26, 2017. The strategy outlined in the draft CES assumes, at a minimum, an extension of the state's Class I Renewable Portfolio Standard, or RPS, to 30% by 2030 will be required, along with consideration of the role of other carbon-free resources such as nuclear and large-scale hydroelectric. A final CES is expected to be issued in 2018.

On Dec. 15, 2017, the DEEP issued a draft request for proposal for comment, seeking bids for off-shore wind, fuel cell, fuel cells combined with combined heat and power, and anaerobic digestion. (Section updated 2/8/18)

Reliability Issues

In accordance with legislation enacted in 2012, the PURA has established electric and gas utility emergency performance standard levels. The law requires the PURA to allow electric or gas companies to recover the reasonable costs they incur for maintaining or improving their infrastructure's resiliency, pursuant to plans approved by the PURA, in order to meet the PURA's standards.

In 2012, the PURA found Connecticut Light & Power, or CL&P, to have been "deficient and inadequate" in its preparedness for and response to Hurricane Irene and a 2011 Nor'easter. The PURA indicated that these findings would be taken into consideration upon a request by CL&P for recovery of related costs. In 2014, the PURA, as part of a CL&P rate case, ordered that a 15-basis point ROE penalty be in place for one year related to the company's response to the 2011 storms.

In 2013, the PURA concluded its review of the performance of the electric and gas distribution companies in response to 2012's Hurricane Sandy. The PURA found that the utilities performed in a generally acceptable manner in preparing for, and responding to, the storm. The PURA concluded that CL&P's emergency planning and organization functions had "clearly improved" since 2011.

In 2014, the PURA approved recovery of $365 million of storm costs, with carrying charges, associated with five major storms that occurred in 2011 and 2012, and ordered CL&P to capitalize $17.9 million of additional deferred storm costs. CL&P had proposed to recover $414 million of storm costs over a six-year period. In December 2014, when CL&P's merger-related base rate freeze expired, the company began recovering roughly $300 million in distribution rates over a six-year period, net of $65 million of Department of Energy Phase II damage proceeds. For further details, see the Merger activity section.

The PURA initiated an investigation in December 2017 to: assess the existing state of each electric distribution company's distribution systems and plans; identify the near- and long-term needs of the distribution systems and what is driving them; and, consider whether any new or modified planning objectives, metrics, solutions, performance incentives, oversight and/or procurement mechanisms should be implemented, in light of the evolving nature of the distribution grid and the electric system itself. Areas of focus are to include: integration of distributed energy resources; modernizing data sensing, analytics, control and communications capabilities; considering alternatives to traditional capacity solutions; and implementing appropriate rate design to optimize system benefits. The investigation is to cover distribution system planning including: system resiliency, reliability, infrastructure replacement, grid-side enhancements and demand forecasts. (Section updated 2/8/18)

Emissions Requirements

Under Connecticut's greenhouse gas goals, the state is to reduce greenhouse gas emissions to a level that is at least 10% below 1990 levels by January 2020, and 80% below 2001 levels by January 2050. A Governor's Council on Climate Change was created to ensure that the state meets is greenhouse gas reduction goals.

Connecticut is part of the Regional Greenhouse Gas Initiative, or RGGI, whereby nine Northeastern and Mid-Atlantic states jointly designed a cap-and-trade program that caps power plants' CO_2 emissions. The 2017 RGGI cap is 84.3 million short tons. The RGGI cap declines 2.5 percent each year until 2020. In August 2017, the RGGI states announced a proposed regional cap trajectory that will provide an additional 30% cap reduction by the year 2030, relative to 2020 levels.

In 2015, the EPA released the final version of its Clean Power Plan, or CPP, calling for a 32% reduction nationwide in the domestic power sector's carbon dioxide emissions by 2030, versus 2005 levels. For Connecticut, the plan specified a 7% reduction.

Although the CPP is currently before the D.C. Circuit, the EPA requested that the cases be held in abeyance, and the request was subsequently approved. The agency is required to submit status reports at 30-day intervals with the court. On Oct. 10, 2017, EPA Administrator Scott Pruitt began the formal process of reversing the efforts made to date to implement the CPP. (Section updated 2/8/18)

Rate Structure

On Dec. 20, 2017, the PURA established a methodology to be employed to determine the maximum residential customer charge, or MRCC, for residential non-heating electric customers of United Illuminating, or UI, and Connecticut Light & Power, or CL&P in accordance with legislation enacted in 2015. The legislation required the PURA to establish a MRCC for non-electric heating residential service in each electric utility's next rate case after July 1, 2015. Under the law, the PURA is required to adjust the residential customer charge "to recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service." The law prohibits PURA, when determining new residential fixed charges, from causing a cost-shift to other rate classes. The law was first implemented for UI in a rate case decided in December 2016. In that case, the PURA established a MRCC of $9.64, about a 45% reduction from the company's rate of $17.25.

Net energy metering — CL&P and UI are required to provide net metering to customers that generate electricity using Class I renewable-energy resources — solar, wind, landfill gas, fuel cells, sustainable biomass, ocean-thermal power, wave or tidal power, low-emission advanced renewable-energy conversion technologies, and hydropower facilities — of 2 MW in capacity or less.

There is no limit on the aggregate capacity of net-metered systems in a utility's service territory. Any net excess generation, or NEG, during a monthly billing period is carried over to the following month as a kWh credit for one year. At the end of the year, the utility reimburses the customer for any remaining NEG at the "avoided cost of wholesale power."

Virtual net energy metering is permitted for state, municipal and agricultural customers for the installation of Class I and Class III resources of 3MW in capacity or less. The program is capped per sector. Production from the customer-generator is first used to reduce the electric consumption of the host. Surplus production may be assigned virtually to reduce the electric bill of one or more beneficial accounts. A monthly credit is calculated for surplus production. The credit is calculated using the generation charge and a portion of the transmission and distribution charges of the host's tariff. Each month the credit, if any, is to be credited to beneficial accounts based on proportional consumption. If the host produces more kWhs than both the host and beneficial accounts use in a billing period, then the excess kWhs accumulate and are applied to future electric bills within the calendar year. Ultimately, any unassigned credits that remain at the end of the calendar year are credited to the host and beneficial accounts.

Legislation enacted in 2015, required the Connecticut Department of Energy and Environmental Protection, or DEEP, to create a two-year shared energy facility, or community solar pilot program. The shared clean energy facility must be Class I renewable energy sources; have nameplate capacity of 4 MW or less, and have at least two subscribers. The facilities may be owned by any for-profit, or not-for-profit organization, and may contract third party entity to build, own, or operate such facilities. The total capacity of the project under the pilot program is capped at 6 MW, with 2 MW allocated to the service area of UI and 4 MW allocated to the service area of CL&P. The DEEP is to file a report analyzing the success of the pilot program with recommendations if the program should be made permanent by July 1, 2018. (Section updated 2/8/18)

General Information

Contact Information	2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 (800) 342-3552
	http://www.psc.state.fl.us
Number of Commissioners	5 of 5
Selection Method	Commissioners: Gubernatorial appointment, Senate confirmation Chairperson: Elected by fellow Commissioners
Term of Office	Commissioners: 4 years Chairperson: 2 years
Chairperson of Commission	Arthur Graham
Deputy Chairperson of Commission	NA
Governor	Charles J. "Charlie" Crist Jr. (I)
Service Regulated	Electric cooperatives, Electric utilities, Gas utilities, Hazardous waste carriers, Power generation companies, Telecommunications utilities, Water utilities
Commission Ranking	Above Average/2 (5/11/2017)
Commmission Budget	$25 million
Commissioner Salaries	Commissioners: $131,000 Chairperson: $131,000
Size of Commission Staff	275
Company Name, Abbreviated	Florida Public Service Commission's Rate Case History
Research Notes	RRA Articles
RRA Contact	Dan Lowrey

Commissioners

Person's Name	***Party Abbreviation***	***Date Role Began***	***Term Ends***
Arthur Graham Chairman	R	07/2010	01/2022
Julie Brown	R	01/2011	01/2019
Donald Polmann	R	01/2017	01/2021
Gary F. Clark	R	09/2017	01/2019
Andrew Giles Fay	R	02/2018	01/2022

RRA Ranking History

Date of Ranking Change	***Commission Ranking***
5/11/2017	Above Average / 2
1/16/2013	Above Average / 3
1/13/2010	Average / 1

Date of Ranking Change	Commission Ranking
10/2/2009	Above Average / 3
7/7/1986	Above Average / 2
7/2/1982	Above 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

Commissioner selection criteria — Commissioners are appointed by the governor from a list of nominees submitted by a 12 member PSC Nominating Council. Senate confirmation is required.

Commission chairmanship — On Nov. 7, 2017, Commissioner Arthur Graham was elected PSC Chairman for a two year term that commenced on Jan. 2, 2018.

Commission members — On Sept. 15, 2017, Gov. Scott appointed Commissioner Arthur Graham to a new PSC term that commenced on Jan. 2, 2018 and extends until Jan. 1, 2022. In addition, there was a vacancy on the PSC for a term that commenced in January 2018 and extends to January 2022. Florida Gov. Rick Scott on Feb. 2, 2018, appointed Andrew Fay, special counsel and the director of legislative affairs, cabinet affairs, and public policy for Attorney General Pam Bondi, to the PSC. He fills a vacant seat for a term ending Jan. 1, 2022. Commissioners Clark, Graham and Fay were confirmed by the Florida Senate in March 2018.

Services regulated — The PSC has jurisdiction over the rates charged and services provided by all investor-owned electric, gas, and roughly half of the state's water and waste-water utilities. The PSC also has limited rate structure jurisdiction over municipal and rural electric cooperatives to ensure that rates are not discriminatory. In addition, the PSC has jurisdiction over all electric utilities' territorial boundaries, bulk power planning, power plant and transmission line siting, safety standards (including municipals and cooperatives), and intrastate natural gas pipeline siting.

Staff contacts — Beverlee DeMello, Asst. Dir., Consumer Assistance and Outreach, (850) 413-6482

(Section updated 2/13/18)

RRA Evaluation

Florida regulation is viewed as quite constructive from an investor perspective by Regulatory Research Associates, an offering of S&P Global Market Intelligence. In recent years, the PSC has issued a number of decisions, most of which adopted multi-year settlements that were supportive of the utilities' financial health. Florida has not restructured its electric industry, and the state's utilities remain vertically integrated and are regulated under a traditional framework. PSC-adopted equity returns have tended to exceed the industry averages when established, and the commission utilizes forecasted test years and frequently authorizes interim rate increases. As a result, utilities are generally accorded a reasonable opportunity to earn the authorized returns. In addition, legislation enacted in the last few years established constructive rate treatment for nuclear and integrated gasification combined cycle coal power plants, including allowing a cash return on construction work in progress outside of the base rate case process. However, it is questionable if any of the state's electric utilities will proceed with the construction of a new nuclear power plant in the foreseeable future, given the challenges facing neighboring utilities with such projects underway. In 2015, legislation was enacted that permits the state's electric utilities to securitize certain nuclear generation retirement or abandonment costs, and one of the state's major companies did so in 2016. Mechanisms are in place that allow utilities to reflect in rates, on a timely basis, changes in fuel, purchased power, certain new generation, conservation, environmental compliance, purchased gas and other costs. On a somewhat less positive note, a 2016 Florida Supreme Court ruling overturned a PSC order authorizing an electric utility to include in rate base its investment in certain natural gas reserves. RRA now accords Florida regulation an Above Average/2 ranking. (Section updated 12/21/17)

Commission Staff

The PSC staff consists of approximately 275 members. With the exception of management positions and attorneys, most are filled under, and protected by, the State Career Service System. (Section updated 12/21/17)

Consumer Interest

The PSC staff provides recommendations to the commission in all major proceedings. The Office of Public Counsel, or OPC, was established by the Joint Legislative Auditing Committee of the Legislature, or JLAC, to represent the people of the state before the commission. The Public Counsel is appointed by the Joint Committee on Public Counsel Oversight and is subject to biennial reconfirmation by this committee. The current Public Counsel is J.R. Kelly. Commercial and industrial customers, in particular the Florida Retail Federation and Florida Industrial Power Users Group, regularly participate in PSC proceedings. (Section updated 12/21/17)

Rate Case Timing/Interim Procedures

A requested base rate increase becomes effective at the expiration of a 60-day period unless the application is suspended by the PSC. The commission is permitted to suspend a rate increase application for a maximum of eight months from the filing date. In fully litigated base rate cases, the PSC generally issues verbal decisions approximately one month prior to the end of the eight month suspension period. Final written orders are usually issued near the expiration of the eight-month suspension period.

Under the Proposed Agency Action, or PAA, procedure, which has been used in relatively non-controversial proceedings, the PSC may approve requested actions without a hearing, in which case a substantially affected party has 21 days to file a protest and request an evidentiary hearing. If no such petition is filed, the PSC ruling stands; if a protest is filed, the protested issues are litigated.

Interim base rate increases are statutorily permitted and frequently have been authorized, usually becoming effective roughly three months after an initial filing is tendered. The utility is not required to demonstrate emergency conditions or financial hardship in order for an interim hike to be authorized. Interim increases are generally determined on the basis of the utility's achieved rate of return and cost of capital for the most recent 12 month period, utilizing the low end of the equity return range authorized in the company's previous rate case (see the Return on Equity section). Any interim increase is collected subject to refund with interest. (Section updated 12/21/17)

Rate Base and Test Period

The PSC generally relies on an average original cost rate base. Court rulings prohibit the commission from using a year-end rate base in a permanent rate case, absent a showing of extraordinary growth; however, the PSC may do so in an interim proceeding. In permanent base rate case decisions, the PSC generally has utilized test periods that are fully or partially forecasted at the time the rate decisions are issued.

The utilities may be authorized a cash return on construction work in progress for any new nuclear or integrated gasification combined cycle facilities and for upgrades to existing facilities that result in increased capacity, and for new, enlarged, or relocated electric transmission lines or facilities that are necessary to serve these power plants. (Section updated12/21/17)

Return on Equity

When determining a utility's authorized ROE, the PSC generally establishes an ROE point that is used to set rates and establishes an allowed range of plus or minus 100 basis points around the point ROE. The commission's point ROE findings have tended to exceed industry average authorizations at the time established.

On Nov. 6, 2017, the PSC adopted a multifaceted settlement, which is effective through December 2021, for Tampa Electric Company, or TEC. Subject to certain adjustment provisions, TEC's authorized return on equity is to remain within a range of 9.25% to 11.25%, with a mid-point of 10.25%. If at any time during the term of the settlement, the average 30 year United States Treasury Bond yield for any period of six consecutive months is at least 4.6039%, the trigger point, TEC's authorized ROE would be increased by 25 basis points to be within a range of 9.5% to 11.5%, with a midpoint of 10.5% for the remainder of the term of the settlement, and thereafter until the PSC resets the company's rates and its authorized ROE. If the trigger point is reached and the revised authorized ROE becomes effective, this revised authorized ROE range and midpoint would be used for the remainder of the settlement's term for all regulatory purposes, and thereafter until changed by an order of the commission.

On April 4, 2017, the PSC adopted a settlement, thereby authorizing Gulf Power, or GP, to continue its previously authorized

10.25% equity return, the midpoint of an allowed range of 9.25% to 11.25%.

On Nov. 29, 2016, following a settlement, the PSC authorized Florida Power & Light, or FP&L, a 10.55% ROE, just below the midpoint of an allowed range of 9.6% to 11.6%. In a September 2014 electric rate case decision for Chesapeake Utilities subsidiary Florida Public Utilities, or FPU, the PUC approved a settlement that specified a 10.25% ROE, the mid-point of a 9.25%-to-11.25% range.

In 2010, the PSC authorized Duke Energy Florida, or DEF, formerly Florida Power, a 10.5% ROE, the midpoint of an allowed range of 9.5% to 11.5%. As a result of 2012, 2013 and 2017 settlements, the 10.5% ROE and 9.5%-to-11.5% ROE range are to be maintained through 2021. FP&L, DEF and GP are subsidiaries of NextEra Energy, Duke Energy and Southern Company, respectively.

Regarding gas utilities, in 2009, the PSC authorized TECO Energy subsidiary Peoples Gas System, or PGS, a 10.75% ROE, the midpoint of an allowed range of 9.75% to 11.75%. However, on Feb. 7, 2017, the PSC adopted a settlement that, among other things, reduced the low end point of PGS' authorized ROE range to 9.25% from 9.75%. In a gas rate case decision issued in 2009, the PSC authorized FPU a 10.85% ROE, the midpoint of an allowed range of 9.85% to 11.85%. An 11.25% ROE established for Pivotal Utility Holdings, or PUH, in 2004, was the midpoint of an authorized range of 10.25% to 12.25. PUH is a subsidiary of Southern Company, and is d/b/a Florida City Gas. (Section updated 12/21/17)

Accounting

The PSC allows electric utilities to expense and recover nuclear plant decommissioning costs through rates, with these amounts placed in external trusts. Florida Power & Light's, or FP&L's, nuclear decommissioning accrual has been suspended since 2006 due to the adequacy of the decommissioning fund.

Duke Energy Florida's, or DEF's, annual accruals for nuclear decommissioning have been suspended since 2002 due to the adequacy of the decommissioning fund. Since 2010, DEF and FP&L have been authorized to utilize depreciation reserve balances to reduce depreciation expense and are to continue such treatment through 2018 and 2020, respectively, as part of settlements adopted by the PSC in 2013 and 2016, respectively (see the Alternative Regulation section).

State law authorizes recovery of prudently incurred preconstruction costs of nuclear and integrated gasification combined-cycle, or IGCC, plants through a utility's capacity cost recovery clause, with these costs to accrue a return equal to that used to calculate the utility's allowance for funds used during construction, or AFUDC. Also included in the capacity cost recovery clause is a cash return on construction work in progress, or CWIP. The rate used to calculate the cash return on CWIP is the most recently approved AFUDC rate at the time incremental cost recovery is sought.

A utility is required to obtain PSC approval to proceed with certain preconstruction and with construction work. If a utility does not complete the construction of a nuclear or IGCC plant, it would be permitted to recover all prudent preconstruction and construction costs through its capacity cost recovery clause over a time frame equal to the period during which the costs were incurred or five years, whichever is greater. The unrecovered balance during the recovery period would accrue interest at the utility's authorized midpoint cost of capital, based on the midpoint of the ROE range, or ROE approved for "other regulatory purposes" if the company is not authorized a specific ROE or ROE range for rate setting purposes.

Settlements that were adopted by the PSC in 2017, contain provisions to reflect the enactment of tax reform legislation. See the Alternative Regulation section. (Section updated 12/21/17)

Alternative Regulation

The fuel adjustment clause includes a generating performance incentive factor. Additionally, the PSC allows Duke Energy Florida, or DEF, Tampa Electric and Gulf Power to retain 20% of the margins from non-firm energy sales if a three year rolling average threshold of those sales is exceeded. Florida Power & Light, or FP&L, is under an incentive framework that was most recently authorized as part of a general rate case settlement approved by the PSC in November 2016 (see the Adjustment Clauses section).

On Nov. 6, 2017, the PSC adopted a multifaceted settlement for Tampa Electric Company, or TEC. Except as otherwise specified in the settlement, Tampa Electric's, or TEC's, base rates are to be frozen through Dec. 31, 2021. However, the company would be authorized to change its base rates in accordance with procedures identified for the solar base rate adjustment, or SoBRA, mechanism and to reduce rates in accordance with any federal income tax reform that may occur during the term of the settlement. TEC is permitted to implement a SoBRA mechanism that allows the company to install and receive cost recovery for up to 600 MW of photovoltaic solar generation. The earliest date of any rate change associated with the solar capacity additions and the maximum incremental annualized revenue requirement under the SoBRA are as follows: Sept. 1, 2018, 150 MW at $30.6 million; Jan. 1, 2019, an incremental 250 MW at $50.9 million; Jan. 1, 2020, an additional 150 MW at $30.6 million; and Jan. 1, 2021, an incremental 50 MW at $10.2 million. Thus, the maximum cumulative revenue requirement for the installation of the 600 MW of capacity would be $122.3 million by Jan. 1, 2021. The total installed capital cost of a project eligible for cost recovery through a SoBRA may not exceed $1,500 per kWac.

Since federal tax reform has been enacted before TEC's next general base rate case, the company is to quantify the impact on its Florida retail jurisdictional net operating income. TEC also is to adjust any SoBRAs that have not yet gone into effect to specifically account for tax reform. The impacts of tax reform on base revenue requirements are to be flowed back to retail customers within 120 days of when the tax reform becomes law.

In addition, TEC may petition the PSC for recovery of costs associated with any tropical systems named by the National Hurricane Center without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. The settlement specifies that recovery of storm costs from customers would begin, on an interim basis and subject to refund following a hearing or a full opportunity for a formal proceeding, 60 days following the filing of a cost recovery petition with the PSC and would be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. If the company's reasonable and prudent storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh would be recovered in a subsequent year or years as determined by the commission, after hearing or after the opportunity for a formal proceeding has been afforded to all substantially affected persons or parties. The settlement permits the replenishment of TEC's storm reserve to $55.9 million.

On Oct. 17, 2017, the PSC adopted a multiyear settlement for DEF that impacts several areas of the company's operations. The settlement extends the base rate freeze specified in a 2013 settlement from Dec. 31, 2018 through year end of 2021, unless Duke Energy Florida's, or DEF's, earnings are outside a 9.5% to 11.5% ROE band, in which case a party can request that the settlement be modified. However, DEF is permitted to increase base rates by $67 million per year in 2019, 2020 and 2021, as well as increase base rates for solar generation.

In addition, the settlement specifies that DEF will not continue with the development of the two unit, 2,200 MW Levy nuclear project. The company is to write off all costs related to obtaining the Levy combined construction and operating license, or COL, including allowance for funds used during construction, or AFUDC, and all remaining but unrecovered Levy Nuclear Project costs, including the retail portion of the Westinghouse Electric Co. LLC termination fee.

If the enacted tax reform legislation results in a decrease in base revenue requirements, DEF would retain 40% of any impacts each year, up to $50 million pre-tax, to accelerate the depreciation of Crystal River coal units 4 & 5. All remaining impacts would be flowed back to customers through a one-time base rate decrease.

If tax reform results in an increase in base revenue requirements, DEF would defer those impacts to a regulatory asset to be recovered in base rates, with changes effective no earlier than January 2022. Excess deferred taxes would be flowed back to customers over time either consistent with the time period specified by the tax reform law, or over 5 or 10 years, depending on whether the cumulative regulatory liability is below or above $200 million, respectively.

DEF may construct or acquire 700 MW of solar generation between 2018 and 2022, limited to a cumulative annual total of 350 MW by 2019, 525 MW by 2020 and 700 MW by 2022. Costs must be reasonable and are to be capped on a weighted average basis at $1,650/kWac per filing. Beginning on or after January 2019, upon commission approval and commercial operation of each plant, DEF is to commence recovering the revenue requirements in base rates, and a 10.5% ROE would be utilized to calculate the revenue requirements.

DEF may implement a 50-MW battery storage pilot program, with costs not to exceed $2,300 per kWac, to be recovered in DEF's next base rate proceeding. DEF is authorized to deploy a minimum of 530 electric charging stations at an investment of up to $8 million. All capital costs and operating expenses are to be deferred to a regulatory asset that is to accrue AFUDC. DEF is authorized to begin requesting recovery of the regulatory asset over a four-year period after 2021.

In addition, DEF may petition the PSC for recovery of costs associated with any tropical systems named by the National Hurricane Center without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. The adopted settlement specifies that recovery of storm costs from customers would begin, on an interim basis and subject to refund following a hearing or a full opportunity for a formal proceeding, 60 days following the filing of a cost recovery petition with the PSC and would be based on a 12 month recovery period. The approved settlement permits the replenishment of DEF’s storm reserve to $132 million.

In April 2017, the PSC adopted a settlement in a Gulf Power, or GP, General rate case that establishes a mechanism for addressing any federal corporate income tax reforms that may occur between the date of its approval and GP's next general base rate case. Within 60 days of any federal tax reforms, GP is to file with the PSC the revenue requirement impacts of such change and identify the resulting regulatory asset or liability. Such asset or liability may be addressed in either a limited proceeding before this commission or in GP's next general base rate proceeding.

On Nov. 29, 2016, the PSC adopted a four-year settlement for Florida Power & Light, or FP&L, that specifies a multi-step rate increase and possible additional rare increases, subject to certain conditions, through a solar base rate adjustment mechanism. The adopted settlement specifies a 10.55% authorized ROE for FP&L, just below the mid-point of an authorized ROE range of 9.6% to 11.6%. If FP&L's earned ROE falls below 9.6%, the company will be permitted to request a base rate increase. If FP&L's earned ROE exceeds 11.6%, any party other than FPL may seek a review of FPL's base rates. Subject to certain conditions, FP&L may amortize, over the 2017 to 2020 time frame, up to $1 billion of depreciation reserve surplus plus any depreciation reserve surplus remaining under the company's 2012 rate agreement, which extended through the end of 2016, provided that in any year FP&L amortizes at least enough reserve to maintain a 9.6% ROE but does not amortize any reserve that would result in a ROE in excess of 11.6%.

The adopted settlement specifies that FP&L's future storm restoration costs are recoverable on an interim basis beginning 60 days from the filing of a cost-recovery request, but will be capped at an amount that would produce a surcharge no greater than $4 per 1,000 KWH of usage on residential bills during the first 12 months of cost recovery. Any additional costs would be eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FP&L could request an increase to the $4 surcharge limit.

On Feb. 7, 2017, the PSC approved, on an interim basis, Florida Power & Light Co.'s, or FP&L's, Dec. 29, 2016, request to recover, over a 12 month period commencing in March 2017, $318.5 million in costs related to Hurricane Matthew restoration and replenishment of the company's storm reserve. The PSC indicated that residential customers will be assessed a monthly charge of $3.36 per 1,000 kWh of usage. The PSC also indicated that it will schedule a hearing at a later date to determine whether the costs are reasonable and prudent, and the costs recovered will be trued up to those actually expended. The temporary surcharge for Hurricane Matthew restoration expired as of March 1, 2018.

In2014, the PSC approved FP&L's request to invest in natural gas reserves and to recover the related investment through the fuel clause. The commission, however, did not rule on FP&L's request for guidelines for its future gas reserve investment opportunities. In June 2015, the PSC established a maximum allowed annual investment in gas reserves of $500 million versus the requested $750 million. In addition, the PSC capped FP&L's average daily burn from natural gas reserves at 5% in 2015, 10% in 2016, 15% in 2017 and 20% in 2018 and beyond. The company's proposal would have capped its average daily burn from natural gas reserves at 15% in 2015, 20% in 2016 and 25% in 2017 and beyond. The PSC also ruled that the program is to be reviewed no earlier than three years or later than five years after the issuance of a final written order. However, in May 2016, the Florida Supreme Court ruled that the PSC exceeded its authority when it authorized FP&L to invest in natural gas reserves and to recover the associated revenue requirement from customers through its fuel clause.

On Feb. 7, 2017, the PSC adopted a settlement, and as a result, Peoples Gas System, or PGS, will not file a base rate case before Dec. 31, 2020, unless the company's earned ROE falls below 9.25%. In addition, PGS' authorized ROE range, which was established by the PSC in 2009, was modified by reducing the low end point of the authorized range to 9.25% from 9.75%. This new low end point is to remain in effect until the earlier of (1) the effective date of base rates established in PGS's next base rate proceeding or (2) Dec. 31, 2020. In its 2009 decision, the PSC had authorized PGS a 10.75% ROE, the midpoint of an authorized range of 9.75% to 11.75%.

The adopted settlement establishes for PGS new depreciation rates and certain depreciation reserve transfers that are projected to result in a reduction in 2016 depreciation expense of $16.1 million. In addition, the adopted settlement accelerates recovery of environmental cleanup and monitoring costs associated with former manufactured gas plants — old industrial facilities at which gas was produced from coal, oil, and other feedstocks. Also, PGS is authorized to expand its existing accelerated cast iron and bare steel pipe replacement program, which was authorized by the PSC in 2012 — see the Adjustment Clauses section — to include "problematic plastic pipe" replacements, i.e., certain types of plastic pipe that were manufactured before 1983 and which have been found to become brittle under certain conditions. (Section updated 12/21/17)

Court Actions

PSC rate decisions for electric and gas utilities may be appealed to the Florida Supreme Court. Supreme Court judges are appointed by the governor from a list of nominees submitted by a Judicial Nominating Commission. Judges run for retention at the general election preceding the expiration of their six-year term. PSC decisions have generally been upheld.

In May 2016, the Florida Supreme Court ruled, in a six-to-one decision, that the PSC exceeded its authority when, in 2014, it authorized FP&L to invest in natural gas reserves and to recover the associated revenue requirement from customers through its fuel clause (see the Alternative Regulation section). (Section updated 12/21/17)

Legislation

The Florida Legislature is a bicameral body and meets annually, typically for two months from early March to early May. Currently, the Senate is comprised of 24 Republicans, 15 Democrats and one vacancy, while the House of Representatives has 78 Republicans, 41 Democrats and one vacancy.

No major utility related legislation was enacted in the 2016 or 2017 session. The 2017 regular session adjourned on May 8, 2017, and the Legislature is scheduled to convene on Jan. 9, 2018 and adjourn on March 9, 2018. (Section updated 12/21/17)

Corporate Governance

By law, PSC approval is required for the issuance of most utility securities. The PSC may deny the issuance or sale of a security or utility assumption of a liability or obligation if the security, liability or obligation is for non-utility purposes; the PSC must reject the issuance of a security or assumption of a liability or obligation if the utility's ability to provide reasonable service at reasonable rates would be adversely affected. (Section updated 12/21/17)

Merger Activity

The PSC is not statutorily authorized to directly review proposed mergers and acquisitions of regulated utilities. (Section updated 12/21/17)

Electric Regulatory Reform/Industry Restructuring

No substantive restructuring has occurred. (Section updated 12/21/17)

Gas Regulatory Reform/Industry Restructuring

All non-residential customers of natural gas utilities may select a competitive gas supplier and take transportation only service from the utility. Most of the state's local distribution companies, or LDCs, including the largest, Peoples Gas System, maintain the traditional utility role of providing both gas supply and transportation service to residential customers. However, a few very small LDCs are transportation only providers, requiring all their customers, including residential, to contract with a marketer for gas supply. (Section updated 12/21/17)

Securitization

State law permits Florida's utilities, subject to PSC approval, to securitize storm damage restoration costs. In 2006, the PSC authorized Florida Power & Light, or FP&L, to issue $708 million of 12 year bonds to securitize 2004 and 2005 hurricane restoration costs and to rebuild its storm damage reserve. The PSC authorized the company to recover $198.7 million of 2004 restoration costs and $735.6 million of 2005 restoration costs and to rebuild its storm damage reserve to $200 million. The PSC disallowed certain storm restoration costs ($27 million, after tax and net of interest). Net of taxes and allowing for $9.6 million of bond issuance costs, the final amount of the bond issuance was $652 million. The bonds were issued in May 2007.

No other utilities have availed themselves of this securitization option. While Gulf Power filed a petition to securitize certain storm damage related costs, the company voluntarily withdrew its petition, and the PSC did not hold a hearing.

In 2015, House Bill 7109 was enacted authorizing the PSC to allow the state's electric utilities to securitize certain nuclear generation retirement or abandonment costs. Specifically, utilities would be permitted to request PSC authorization to securitize nuclear generation retirement or abandonment costs for plants located in Florida and for which the costs have been found by the PSC to be reasonable and prudent through an order approving a settlement or other order issued before July 1, 2017. If the pretax costs exceed $750 million, the utility would be permitted to issue bonds, with the bonds' principal and interest to be paid by ratepayers through a nuclear asset recovery charge.

In November 2015, the PSC authorized Duke Energy Florida, or DEF, to issue an estimated $1.314 billion of nuclear asset recovery bonds to securitize the regulatory asset associated with the permanent closure of DEF's Crystal River 3 nuclear plant. In addition, the PSC authorized DEF to implement, a non-by-passable nuclear asset recovery charge to be collected on a per kWh basis from applicable rate classes over a period not to exceed 20 years. DEF issued $1.29 billion of nuclear asset recovery bonds in June 2016. (Section updated 12/21/17)

Adjustment Clauses

Fuel and purchased power — The fuel and purchased power cost recovery clause, or FPPCRC, provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12 month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. Subsequent to the November hearings, utilities may seek, or the PSC may require, a mid term modification to the factors if updated projected costs for the year vary from updated projected revenues by plus or minus 10%.

Interest is accrued on both over and under recovered balances. Included in the FPPCRC is a generating performance incentive factor that provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25 basis point ROE spread. The PSC generally requires market based pricing of coal purchased from an affiliate.

The FPPCRC also reflects gains from non-firm energy sales. A three-year moving average based on eligible sales is determined, and 100% of the sales up to this benchmark are credited to ratepayers. For sales above the benchmark, 80% of the gains from such sales accrue to ratepayers, with 20% retained by Duke Energy Florida, Tampa Electric Company, or TEC, and Gulf Power.

As per a settlement adopted by the PSC on Nov. 29, 2016, Florida Power & Light, or FP&L, is to continue a modified incentive mechanism applicable to its wholesale power purchases and sales, as well as asset optimization activities. On an annual basis, FP&L customers will receive 100% of the incentive mechanism gain up to a threshold of $40 million. FP&L will retain 60% and customers will receive 40% of incremental gains between $40 million and $100 million. FP&L and customers will equally share incremental gains in excess of $100 million. Also, FP&L will net economy sales and purchases in order to determine the impact of variable power plant O&M expense. If FP&L executes more economy sales than economy purchases, FP&L will recover the net amount of variable power plant O&M incurred in a given year. If economy purchases are greater than economy sales, FP&L's customers will receive a credit for the net variable power plant O&M that has been saved in that year. The per-MWh variable power O&M rate used to calculate these costs are to be those included in FP&L's 2017 test year rate increase request, i.e., $0.65/MWh.

Gas industry related — Purchased gas adjustment, or PGA, clauses are in place for the local distribution companies that offer bundled service. The PGA is designed to recover purchased gas costs, and the costs of reserving and utilizing interstate pipeline capacity for the transportation of gas to customers. These charges are adjusted monthly based on a cap approved annually following a PSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true up adjustment to reflect the variance of actual costs and revenues from the projections.

A Cast Iron/Bare Steel Pipe Replacement Rider for Peoples Gas System, or PGS. The rider enables PGS to recover, through an annual surcharge, the costs associated with accelerating the replacement of cast iron and bare steel distribution pipes on its system over a 10-year period beginning Jan. 1, 2013. Under the rider, PGS is authorized to spend an additional $7 million per year on distribution pipe replacement; the company previously was authorized to spend $1 million annually, as established by the PSC in 2009 in the company's last general rate case. However, effective January 2013, the company is authorized to spend at least $8 million per year and earn a return on its additional investment equivalent to its cost of capital, as reflected in PGS' earnings surveillance report for December of each year, incorporating the company's currently authorized return on equity of 10.75%.

Similar riders, known as Gas Reliability Infrastructure Programs, for the smaller gas utilities such as Florida Public Utilities, the Florida division of Chesapeake Utilities, and Pivotal Utility Holdings, or PUH. For PUH, the plan is known as the Safety, Access, and Facility Enhancement, or SAFE, program, and encompasses a 10-year, $105 million project to replace aging pipes to improve system safety and reliability that began in 2015.

Other — A capacity cost recovery clause, or CCRC, is also in place as a part of the FPPCRC. The capacity or demand component of purchased power agreements are flowed through this clause on an annual basis. In addition, utilities may recover all prudently incurred site selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle, or IGCC, power plants through the CCRC. A cash return on construction work in progress for nuclear plant construction and uprates and IGCC construction is also reflected in the CCRC.

In 2013, the PSC adopted a settlement thereby authorizing TEC a $70 million multi-step base rate increase and a subsequent, additional $110 million generation base rate adjustment, or GBRA, mechanism rate increase. The GBRA rate increase became effective on Jan. 1, 2017, and reflected the conversion of units 2 to 5 of the Polk Power Station from gas fired, simple cycle combustion turbines to combined cycle combustion turbines. The GBRA is a mechanism utilized by the PSC that permits the utility, without it filing another base rate case, to implement changes in base rates for costs associated with planned and approved generation projects.

Pursuant to statutes, the PSC has established an Energy Conservation Cost Recovery Clause, or ECCRC, for electric and gas conservation related expenditures. The ECCRC factors are based on projected costs and subject to true up, similar to the FPPCRC mechanism. Also pursuant to statutes, the commission has established an Environmental Cost Recovery Clause that enables each utility to recover compliance costs associated with environmental laws or mandates that became effective after 1993. The clause is reviewed annually and permits recovery of environmental operations and maintenance costs, related capital investments, and a return on such capital investments.

Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage. (Section updated 12/21/17)

Integrated Resource Planning

For major projects, utilities must obtain a certificate of need from the PSC prior to commencing construction. A cost estimate is included in the need determination, and utility cost recovery is not challenged if costs are at or below the estimate. For costs that exceed the estimate, the utility is required to show that these costs are justified before they can be recovered.

In general, electric utilities are required to annually file a 10-year generation site plan that includes a projection of customer usage and peak demand and capacity.

The PSC's competitive bidding rules, developed in accordance with state law, generally require investor owned utilities, or IOUs, to issue requests for proposals for any new generating project of 75 MWs or greater, exclusive of single cycle combustion turbine facilities. The bidding requirement can be waived by the PSC if the IOU can demonstrate, on an individual case basis, that it is not in the best interests of its ratepayers. State law exempts nuclear power plants from the requirement of a competitive bid, and directs the PSC to consider fuel diversity and reliability in determining the need for a proposed power plant.

State law requires the PSC to establish conservation goals to reduce the growth rates of weather sensitive peak demand, to reduce and control the growth rate of electricity consumption and to reduce the consumption of scarce resources such as fossil fuels. In addition, the PSC is to establish goals for demand side energy resources and investments in generation, transmission, and distribution efficiency. Once the PSC has established the goals, utilities subject to the statutes, i.e., all IOUs and two of the state's largest municipal electric utilities, are required to develop and implement cost effective programs to achieve the goals. The PSC must review the demand side management goals no less than every five years.

Florida does not have a formal integrated resource planning process in place for gas utilities. (Section updated 12/21/17)

Renewable Energy

Florida does not have a renewable portfolio standard. A 2012 law repealed Florida's previous legislative mandate to establish a renewable portfolio standard. The 2012 legislation requires the PSC, in its evaluation of an electric utility's 10-year generation site plan, to consider: the amount of renewable energy the utility currently produces or purchases; the amount of renewable energy the utility plans to produce or purchase over the 10-year planning horizon and the means by which the production or purchases will be achieved; and, the utility's indication of how the production and purchase of renewable energy affect its present and future capacity and energy needs. The above provisions concerning renewable energy are to be considered by the PSC in the context of each company's 10-year generation site plan.

Several of the state's electric utilities have announced plans to build utility level solar generating facilities over the next few years.

A settlement adopted by the PSC on Nov. 6, 2017, authorizes Tampa Electric Company, or TEC, to implement a solar base rate, or SoBRA, mechanism that allows the company to install and receive cost recovery for up to 600 MW of photovoltaic solar generation. The earliest date of any rate change associated with the solar capacity additions and the maximum incremental annualized revenue requirement under the SoBRA are as follows: Sept. 1, 2018, 150 MW at $30.6 million; Jan. 1, 2019, an incremental 250 MW at $50.9 million; Jan. 1, 2020, an additional 150 MW at $30.6 million; and Jan. 1, 2021, an incremental 50 MW at $10.2 million. Thus, the maximum cumulative revenue requirement for the installation of the 600 MW of capacity would be $122.3 million by Jan. 1, 2021.

The total installed capital cost of a project eligible for recovery by TEC through a SoBRA may not exceed $1,500 per kWac. This installed cost cap applies on a per project basis and includes all costs required to make each of the projects fully operational. The SoBRA is to be based on a 10.25% ROE and a 54% equity ratio, on a financial basis. If TEC's actual installed cost for a project is less than the installed cost cap, the company's customers and TEC would share the difference, with 75% of the difference inuring to the benefit of customers and 25% to the company.

In a settlement adopted by the PSC on Oct. 25, 2017, Duke Energy Florida, or DEF, may construct or acquire 700 MW of solar generation between 2018 and 2022, limited to a cumulative annual total of 350 MW by 2019, 525 MW by 2020 and 700 MW by 2022. Costs must be reasonable and are to be capped on a weighted average basis at $1,650/kWac per filing. Beginning on or after January 2019, upon commission approval and commercial operation of each plant, DEF is to commence recovering the revenue requirements in base rates, and a 10.5% ROE would be utilized to calculate the revenue requirements.

Pursuant to a settlement approved by the PSC on Nov. 29, 2016, Florida Power & Light, or FP&L, may increase base rates through a SoBRA mechanism, associated with the annual addition of up to 300 MW of new solar generation in each year 2017 through 2020. The company is permitted to carry forward any unused MWs to subsequent years. FP&L is required to demonstrate that any proposed solar facilities are cost effective and scheduled to be in service before Dec. 31, 2021, and the company has agreed to an installed cost cap of $1,750 per KW. (Section updated 12/21/17)

Emissions Requirements

An executive order issued in 2007 by then-Gov. Charlie Crist required utilities to reduce greenhouse gas emissions to no more than 2000 levels by 2017, to no greater than 1990 levels by 2025, and to no more than 20% of 1990 levels by 2050. However, with the election of Republican Gov. Rick Scott in 2010, the order has no force of law, and Gov. Scott has not issued an analogous executive order. (Section updated 12/21/17)

Rate Structure

The PSC has required the elimination of declining block rates for electric utilities and has established an inverted residential rate structure for Florida Power & Light, Duke Energy Florida, or DEF, and Tampa Electric, or TEC.

The major electric utilities offer optional time of-day rates to commercial customers.

DEF, TEC, and Gulf Power offer negotiated contract rates for attracting or retaining significant commercial and industrial load. To be eligible, the customer must be at risk, i.e., have an alternative to taking power from the incumbent utility, either by relocating, not locating in the territory, or installing self-generation. The individual contracts are considered confidential and are not subject to prior PSC approval; however, the commission may review any contract for prudence prior to allowing the shortfall in revenue from tariffed rates to be recovered from ratepayers in general. (Section updated 12/21/17)

General Information

Contact Information	One South Station Boston, MA 02110 (617) 305-3500
	https://www.mass.gov/orgs/department-of-public-utilities
Number of Commissioners	3 of 3
Selection Method	NA
Term of Office	Commissioners: 4 years Chairperson: 2 years
Chairperson of Commission	Angela O'Connor
Deputy Chairperson of Commission	NA
Governor	Charlie Duane Baker (R)
Service Regulated	Bus companies, Cable television companies, Electric utilities, Gas utilities, Motor carriers, Power generation companies, Securities companies, Water utilities
Commission Ranking	Average/2 (3/23/2018)
Commmission Budget	$12.80 million
Commissioner Salaries	Commissioners: $121,400 - $127,100 Chairperson: $129,000
Size of Commission Staff	140
Company Name, Abbreviated	Massachusetts Department of Public Utilities's Rate Case History
Research Notes	RRA Articles
RRA Contact	Lisa Fontanella

Commissioners

Person's Name	***Party Abbreviation***	***Date Role Began***	***Term Ends***
Angela O'Connor Chairman	I	01/2015	01/2019
Robert Hayden	R	01/2015	01/2019
Cecile M. Fraser	D	06/2017	04/2021

RRA Ranking History

Date of Ranking Change	***Commission Ranking***
3/23/2018	Average / 2
4/9/2013	Average / 3
4/13/2011	Average / 2
4/1/1998	Average / 1
7/14/1995	Average / 2

Date of Ranking Change	Commission Ranking
7/8/1986	Average / 3
1/4/1984	Average / 2
7/1/1983	Average / 3
7/2/1982	Below Average / 1

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

Department Membership — Commissioner Westbrook continues to serve pending reappointment or replacement.

Commissioner Selection Criteria - Commissioners are appointed by the Secretary of the Office of Energy and Environmental Affairs, with the governor's approval. The current secretary, who is a member of the governor's cabinet, is Matthew Beaton. Commissioners are required to have a background or expertise in electricity or natural gas matters, and no more than two members may be from the same political party.

Commissioner Terms - Two of the three commissioners serve conterminously with the governor and one commissioner serves a term that begins and ends two years after each new gubernatorial term. Of note, there appears to be some ambiguity in the 2007 law that reorganized the Massachusetts Department of Telecommunications and Energy into two agencies — the DPU, which regulates electric and natural gas utilities, and the Department of Telecommunications and Cable. This ambiguity relates to the month of the end date for the commissioner who is to serve the term ending two years after each new gubernatorial term. As interpreted by the DPU, and unless legislatively clarified, since the law went into effect in the month of April, the term in question is to end in April. With regard to the DPU chairman, it appears that under the 2007 law, although not clearly specified, the chairman is designated by the Secretary of the Office of Energy and Environmental Affairs, with the approval of the governor.

Services Regulated - In addition to electric, gas, and water utilities, the DPU regulates steam generation companies, certain aspects associated with the siting of energy facilities, tow companies providing involuntary towing services, household goods moving companies, railway safety, transportation network companies, and issuance of securities by utilities.

Staff Contact:

Matthew Campbell, Chief of Staff (617) 305 3758

(Section updated 2/22/17)

RRA Evaluation

The Massachusetts regulatory environment has become relatively balanced from an investor viewpoint. Recently, the DPU's ROE determinations, in the most recently completed cases over the past couple of years, have been above the prevailing nationwide averages at the time of the decisions. Historically, settlements provided the basis for many DPU rate decisions; however, most decisions over the past several years have been fully litigated. State statutes call for electric utilities to file rate cases with the DPU at least every five years, and gas companies to file rate cases at least every 10 years. The law also prohibits the adoption of a settlement in an electric rate case more than once every 10 years and increased from six to 10 months the time the DPU has to render a final decision in a rate case. Prior to the enactment of the aforementioned law, there were no rate case filing requirements or restrictions on the use of settlements, and rate case decisions usually followed settlements. Recently, the DPU approved an electric multi-year performance-based ratemaking plan that allows for annual rate adjustments to reflect capital additions for distribution system upgrades and contains earnings sharing provisions. Electric industry restructuring was implemented some time ago, and although the electric utilities retain the obligation to serve customers not served by competitive electric suppliers, the companies are insulated from market-price fluctuations. The state is very supportive of renewable resource development, and despite industry restructuring, the state's electric distribution utilities are permitted to own solar generation and energy storage systems. Also, the DPU has approved automatic adjustment mechanisms that allow the utilities to reflect in rates variations in certain costs outside of a full rate proceeding. Supplier choice for natural gas has been in place for quite some time, and the incumbents continue to provide service to customers who do not select a competitive supplier; like the electric utilities, the gas utilities are insulated from commodity market-price fluctuations. In the past, the DPU approved several utility-related mergers without imposing onerous restrictions. However, more recently, the DPU has established a more stringent merger review policy, and has imposed dividend limitations and other restrictions as part of merger approval proceedings. To reflect recent constructive rate decisions, the most recent of which being the adoption of the performance-based ratemaking plan, RRA is raising the ranking of Massachusetts regulation to Average/2 from Average/3. (Section updated 3/23/18)

Consumer Interest

Represented by the Office of Ratepayer Advocate within the Office of the Attorney General, or AG. The current AG is Democrat Maura Healey, who was elected in 2014, to a four-year term extending to January 2019. Rebecca Tepper is Deputy Chief of the Energy and Environment Bureau and head of the Energy Division within the Attorney General's office. (Section updated 2/22/17)

Rate Case Timing/Interim Procedures

State statutes require electric utilities to file rate cases with the DPU at least every five years, and gas companies to file rate cases at least every 10 years. The DPU is prohibited from adopting a settlement in an electric rate case more than once every 10 years. The DPU is required to render a final decision in a rate case in 10 months. Prior to 2012, there were no rate case filing requirements or restrictions on settlement adoptions. Interim rate increases have rarely been sought or granted for energy utilities. Interim increases are only granted in situations where a financial emergency exists and where the company can demonstrate that interim relief is the only way to avoid probable, immediate and irreparable harm either to a company or to the interests of its customers. (Section updated 2/22/17)

Rate Base and Test Period

In traditional rate cases, a historical test year and a year-end original-cost rate base are utilized, with adjustments for "known-and-measurable" changes. Post test-year rate base additions have been permitted only for "significant" investment that has a "substantial" effect on rate base. Historically, a cash return on construction work in progress has not been allowed. (Section updated 2/22/17)

Return on Equity

Historically, ROEs authorized in Massachusetts were generally somewhat below prevailing national averages when established. However, in recent cases the DPU has approved ROEs that were somewhat above prevailing nationwide averages at the time the decisions were rendered.

The most recent electric rate decision in which an ROE was established was issued on Nov. 30, 2017, when NSTAR Electric and Western Massachusetts Electric Company, or WMECO, were authorized a 10% ROE. On Dec. 31, 2017, WMECO and NSTAR Electric merged, with NSTAR Electric as the surviving entity. NSTAR Electric is a subsidiary of Eversource Energy (see the Merger Activity section).

On Sept. 30, 2016, Massachusetts Electric, or ME, and Nantucket Electric, or NE, were authorized a 9.9% ROE. ME and NE are subsidiaries of National Grid USA, or NG-USA, which is a subsidiary of National Grid plc.

The DPU's most rate case decision for Fitchburg Gas & Electric, or FG&E, was issued on April 29, 2016, when the Department adopted a 9.8% ROE for the company's electric and gas operations. FG&E is a subsidiary of Unitil Corporation.

On Feb. 10, 2016, the DPU authorized Liberty Utilities (New England Natural Gas) d/b/a Liberty Utilities, a 9.6% ROE, following a settlement. Liberty Utilities is an affiliate of Algonquin Power & Utilities. In October 2015, the DPU authorized NSTAR Gas a 9.8% ROE. NSTAR Gas is a subsidiary of Yankee Energy System, which is a subsidiary of Eversource Energy.

Also in October 2015, the DPU authorized Bay State Gas a 9.55% ROE, following a settlement. Bay State Gas is doing business as Columbia Gas of Massachusetts, and is a subsidiary of NiSource. In 2010, the DPU authorized NG-USA companies Boston Gas and Colonial Gas 9.75% ROEs.

Berkshire Gas is authorized a 10.5% ROE that was established in a small rate case in 2002. The ultimate parent of Berkshire Gas is Avangrid. (Section updated 2/27/18)

Alternative Regulation

A gas rate case settlement adopted by the DPU in October 2015 for Bay State Gas specified rate increases to be implemented on Nov. 1, 2015 and Nov. 1, 2016; otherwise, the company is effectively subject to a base rate freeze until Nov. 1, 2018.

As specified in a December 2015 DPU order approving Iberdrola USA's proposed acquisition of UIL Holdings and its subsidiary Berkshire Gas, the company's base rates are to be frozen until June 1, 2018.

All electric and gas distribution companies that achieve targeted performance levels for energy efficiency programs may earn an incentive (see the Integrated Resource Planning section).

Under state law, electric distribution companies receive "remuneration" of up to 2.75% percent of the annual payments under long term contracts for offshore wind energy and clean energy generation for the financial obligation of long-term contracts.

The local gas distribution companies may retain 10% of margins from transportation, capacity release, off-system sales, interruptible sales, and portfolio management and optimization agreements. (Section updated 2/22/17)

Court Actions

Department decisions may be appealed directly to the Massachusetts Supreme Judicial Court, or SJC. Justices are appointed by the governor.

On Aug. 17, 2016, the SJC vacated an October 2015, DPU order that would have permitted the Department to approve ratepayer-backed, long-term contracts entered into by the state's electric distribution companies, or EDCs, for the purchase of natural gas pipeline capacity. In vacating the order, the Court determined that "the order is invalid in light of the statutory language and purpose [of state restructuring law] because, among other things, it would undermine the main objectives of the act and re-expose ratepayers to the types of financial risks from which the legislature sought to protect them." (Section updated 2/22/17)

Legislation

The Massachusetts General Court meets for a two-year session commencing on the first Wednesday in January of each odd-numbered year. While the Court is in session throughout the year, all formal legislative activity of the first year of the session must be concluded by the third Wednesday in November of that year. Formal legislative activity of the second year of the session commences on the first Wednesday of January of even-numbered years. All formal activity of the second year of the session must be concluded by the last day of July. Any bill pending before the General Court at the end of the first year of its biennial session are to carry over into the second legislative year in the same status as it was at the conclusion of the first legislative year.

The 2017 session commenced on Jan. 4. The General Court is bicameral, consisting of the Senate and a House of Representatives. The Senate is currently comprised of 34 Democrats and 6 Republicans and the House consists of 125 Democrats and 35 Republicans.

During the 2016 session, Senate Bill 1979 was enacted. S.B. 1979 raises the caps on net metering for local governments to 8% from 5% of a distribution company's peak load and raises the cap for business and private sector installations to 7% from 4%. The legislation also permits electric distribution companies to adopt a "monthly minimum reliability contribution" for net metering customers, subject to DPU approval, once the state reaches 1,600 MW in aggregate installed solar capacity (see the Rate Structure section).

House Bill 4568, also enacted in 2016, requires the state's electric distribution companies to jointly solicit and enter into long term contracts to procure 1,600 MWs of offshore wind power and 1,200 MW of clean energy generation, including large-scale hydropower. In addition, the law contains provisions with respect to energy storage (see the Renewable Energy section).

Thus far this year, legislators have filed a bill that would require the state to obtain 100% of its energy from renewable resources by 2035. (Section updated 2/22/17)

Corporate Governance

The DPU has authority over mergers and reorganizations involving utilities. Prior to 2008, the merger statutes only covered operating companies; legislative amendments enacted in 2008 and 2012 extended DPU jurisdiction to mergers and acquisitions at the holding company level. In recent mergers, the DPU has approved certain dividend restrictions and utility ring-fencing provisions (see the Merger Activity section). (Section updated 2/22/17)

Merger Activity

When reviewing proposed mergers, Massachusetts law requires the Department to make a determination as to whether the proposed transaction is "consistent with the public interest." Historically, the DPU had employed a "no net harm standard;" however, in 2011, the Department issued an order specifying that a "net benefit" standard will be utilized when reviewing whether a proposed merger satisfies the statutory requirements.

In evaluating a proposed transaction, the DPU considers the: (1) effect on rates, including proposed rate changes; (2) long-term strategies that will assure a reliable, cost-effective energy delivery system; (3) impact on the quality of service including any anticipated interruptions in service; (4) resulting net savings; (5) effect on competition; (6) financial integrity of the post-merger entity; (7) fairness of the distribution of resulting benefits between shareholders and ratepayers; (8) societal costs; (9) effect on economic development; (10) alternatives to the merger or acquisition; and, (11) impact on climate change, including greenhouse gas emissions.

The merger of BEC Energy and Commonwealth Energy System was completed in August 1999 following DPU adoption of a four-year distribution rate freeze for the companies' regulated subsidiaries. The order permitted recovery in future rate proceedings of all merger related costs, including the acquisition premium, through the retention of merger-related savings. As part of a rate settlement adopted by the Department in 2005, then-NSTAR subsidiaries Boston Edison, Commonwealth Electric and Cambridge Electric Light merged into NSTAR Electric effective Jan. 2, 2007. NSTAR has since merged with Northeast Utilities (see below).

In 2000, the merger of New England Electric System, or NEES, and Eastern Utilities Associates was approved in conjunction with an associated 20-year rate plan for then-NEES subsidiary Massachusetts Electric, or ME, and then-Eastern Utilities Associates' subsidiary Eastern Edison, or EE. NEES was the surviving entity. Following the close of the transaction that same year, Eastern Utilities Associates' electric operating subsidiaries were merged with NEES' electric operating subsidiaries, and their rate structures were consolidated; the surviving operating subsidiary is ME. The 20-year rate plan was divided into three periods: a distribution rate cap period — from the merger closing date to February 2005; a distribution rate index period — from March 2005 to year-end 2009 (see the Alternative Regulation section), and an "earned savings period" — 2010-2020, during which ME may retain merger-related savings through distribution rates, to the extent that merger-related savings exceed merger-related costs. National Grid plc subsequently acquired NEES, and NEES is now part of National Grid-USA.

The merger of Northeast Utilities and NSTAR was completed in April 2012, following DPU approval of related settlements, with additional provisions imposed by the Department. After a rebranding effort that commenced in 2015, the company is now known as Eversource Energy. The approved settlements provided for one-time rate credits aggregating to $21 million for customers of NSTAR Electric, NSTAR Gas, and Western Massachusetts Electric, or WMECO, after which base distribution rates for the utilities are to be frozen through Dec. 31, 2015. On Dec. 31, 2017, following DPU approval, WMECO, a former subsidiary of Eversource merged with and into NSTAR Electric, with NSTAR Electric as the surviving entity.

In 1998, the Department approved Eastern Enterprises' proposal to acquire Essex County Gas, or Essex Gas, and the transaction was completed that same year. At the time, Eastern Enterprises was the parent of Boston Gas. Essex Gas customers received a 5% rate reduction, and base rates were frozen through September 2008. In approving the merger, the Department allowed Eastern Enterprises an opportunity to recover merger related costs, including an acquisition premium of $47.1 million through retention of merger-related savings.

In 1999, the Department approved the acquisition of Colonial Gas by Eastern Enterprises, and the transaction closed that same year. In conjunction with the merger, the DPU adopted a settlement providing for a 10-year rate freeze that was in effect through August 2009, for Colonial Gas. Recovery of merger related costs and the acquisition premium was permitted to the extent that recovery of such costs was supported by merger savings. In a 2010 rate decision, Colonial Gas was permitted recovery of only a portion of the acquisition premium based on the DPU's calculation of merger savings; recovery of the entire acquisition premium was allowed on reconsideration in January 2013.

In 2000, KeySpan Corporation acquired Boston Gas, Colonial Gas, and Essex Gas, and in 2007, National Grid acquired KeySpan Corporation. Although DPU approval of National Grid's acquisition of KeySpan was not necessary, the DPU opened an investigation into the public interest aspects of the proposed merger. The DPU ultimately concluded that there was no evidence that the merger would affect the Department's existing authority over the former KeySpan companies. In 2010, the DPU approved the merger of Essex Gas and Boston Gas, with Boston Gas being the surviving entity. There was no acquisition premium associated with this transaction, which was completed that same year.

In 1998, Bay State Gas was acquired by NiSource, following DPU adoption of a settlement that included a five year base rate freeze through October 2004. The merged company was permitted to propose recovery of the annual amortization of an acquisition premium "in future rate proceedings to the extent offset by merger-related savings."

In 2000, Energy East acquired Berkshire Energy Resources. Under the transaction, Berkshire Energy Resources became a subsidiary of Energy East, which was subsequently purchased by Iberdrola SA. Berkshire Energy Resource's principal gas subsidiary is Berkshire Gas. Department approval was not required at that time, as the merger occurred at the holding company level. In 2010, UIL Holdings Corp. and Iberdrola jointly filed for approval of UIL's proposed acquisition of Iberdrola USA's interest in Berkshire Energy Resources. The Department ultimately ruled that its approval was not required for the proposed acquisition; the transaction was completed in November 2010.

In 2000, the DPU approved Southern Union's acquisitions of Fall River Gas and North Attleboro Gas, which was a wholly owned subsidiary of Providence Energy. The Massachusetts operations are now owned by Liberty Utilities (New England Natural Gas), an affiliate of Algonquin Power & Utilities Corp., see below.

In 2008, the DPU approved Unitil Corporation's proposed purchase of Northern Utilities. The company completed the transaction in December 2008.

In December 2013, Southern Union division New England Gas, or NEG, was acquired by Algonquin Power & Utilities subsidiary Liberty Utilities, following DPU approval. The DPU largely adopted commitments outlined by the companies, including: (1) a two-year distribution base rate freeze for the customers of NEG that is to commence upon transaction close; (2) utilization of a rate base offset and credit that will be applied to mitigate any future rate impacts associated with the proposed transaction; (3) a prohibition on Liberty Utilities making any accounting adjustment at transaction close that would increase the net book value of property, plant, and equipment for ratemaking purposes following completion of the transaction; (4) agreement by Liberty Utilities to refrain from seeking recovery of transaction costs associated with the acquisition; (5) an increase in NEG's main replacement activity to at least eight miles of main per year; and, (6) an energy audit of NEG's buildings to be conducted by Liberty Utilities. In addition to the benefits to be derived from the commitments noted above, the DPU noted that the transaction is to provide: annual savings of at least $0.5 million in the first year after transaction close; improvements in customer service functions, specifically the relocation of the customer service center to Massachusetts; job creation in Massachusetts; and, ownership and operation of NEG "by a financially viable company." The DPU indicated that Liberty Utilities would be responsible for achieving the cost savings identified for NEG, and would be required to "track all such savings and present the results as part of the initial filing in its next base rate case." In addition, the DPU ordered NEG, in its next rate case, to provide the Department with an evaluation of the feasibility of accelerating the main replacement rate beyond eight miles per year. NEG is now known as Liberty Utilities (New England Natural Gas), d/b/a Liberty Utilities.

On Dec. 15, 2015, the DPU approved Iberdrola USA Inc.'s, or IUSA's, proposed acquisition of UIL Holdings Corp., following a settlement, and on Dec. 18, 2015, Iberdrola USA and UIL merged to form AVANGRID. The approved settlement provided for Berkshire Gas to provide customers $4 million in rate credits and allocate an additional $1 million to fund job creation, economic development and alternative heating programs. Berkshire's base rates are to be frozen until June 1, 2018. UIL and Berkshire are to maintain current charitable giving and corporate philanthropy programs in Massachusetts for at least four years following the closing of the transaction. Berkshire's existing collective bargaining agreements are to be honored, and for at least three years following transaction close, there are to be no involuntary terminations of UIL or Berkshire employees, except for cause or performance. There is to be no change to the "day-to-day" management and operation of Berkshire as a result of the transaction, and Berkshire's headquarters is to remain in Massachusetts.

The companies were required to create a bankruptcy-remote special purpose entity, or SPE, comprised of four directors appointed by IUSA, including one independent director. UIL, Berkshire Gas and the SPE are to maintain separate books and records and provide access to such books and records to the Department. UIL, Berkshire, and the SPE are to maintain arm's length relationships with each of their affiliates and observe all necessary, appropriate and customary formalities in their dealings with affiliates. The SPE is prohibited from commingling its funds or other assets with any other entity. Berkshire is to maintain separate debt, and must not be responsible for the debts of affiliated companies. Neither UIL nor Berkshire is to incur or assume any debt, including the provision of guarantees or collateral support. The SPE is not to incur or assume any debt unless approved by the Department. Berkshire may participate in money pools where the other participants in such money pools are other regulated utility affiliates in the United States, unless otherwise authorized by the Authority. IUSA and Berkshire are to obtain ratings from two of the three bond rating agencies, and maintain at least an investment grade credit rating. IUSA is prohibited from engaging in an internal corporate reorganization of UIL, Berkshire, or the SPE for which DPU approval is not required without 90 days prior written notification to the Department. Berkshire is restricted from paying dividends if a minimum common equity ratio is not maintained — 300 basis points below the equity percentage used to set rates in the utility's most recent distribution rate proceeding, measured using a trailing 13-month average calculated as of the most recent quarter end, exclusive of goodwill.

In addition, Berkshire Gas is restricted from issuing any dividend to its parent if the utility's corporate issuer or senior unsecured credit rating, or its equivalent, is rated by any of the three major credit rating agencies below investment grade, and from issuing any dividend to its parent if the utility's corporate issuer or senior unsecured credit rating falls to the lowest investment grade rating and there is a negative watch or review downgrade notice for the company by two of the three major credit rating agencies or, alternatively, if such rating falls below investment grade without such notice. If the aforementioned ratings events were to occur, then Berkshire would be precluded from transferring, leasing, or lending any moneys, assets, rights or other items of value to any affiliate without first obtaining DPU approval, and Berkshire would be required to file a plan with the Department within 60 days outlining the actions that are planned to address and rectify the situation.

On Nov. 28, 2017, the DPU approved Eversource Energy's acquisition of Macquarie Utilities Inc. and its subsidiaries, including Aquarion Water. The merger closed on Dec. 4, 2017. In accordance with DPU precedent, Aquarion Water subsidiary Aquarion Water of Massachusetts, or AWC-MA, may seek to recover transaction costs associated with the acquisition in a future rate case. The DPU noted "AWC-MA will bear the burden to demonstrate that such costs are reasonable and that the quantifiable benefits of the transaction outweigh its costs." (Section updated 2/27/18)

Electric Regulatory Reform/Industry Restructuring

Legislation — As required by 1997 legislation, retail electric competition for all

Industry Restructuring: customers began on March 1, 1998, and up-front rate reductions were implemented for customers purchasing power under standard offer service, or SOS, through March 1, 2005. Currently customers who do not choose a competitive supplier receive basic service from their electric distribution companies, sourced from third-party suppliers obtained through a competitive bid process overseen by the DPU; this process is described below.

Divestiture of non nuclear generation facilities was not mandated, but recovery of stranded costs and the use of securitization were permitted only if a utility divested its generation facilities. The savings associated with securitization must be used to benefit ratepayers. Municipalities may aggregate the load of interested consumers within their boundaries.

Company-Specific Plans — In 1997, 1998 and 1999, the DPU approved company-specific transition plans, and virtually all generation assets were divested. The utilities were permitted to recover stranded costs through a transition charge. Securitization of stranded costs was permitted (see the Securitization section).

SOS/Default Service — The utilities were required to provide SOS at capped rates during a transition period that extended through March 1, 2005. SOS rates were subject to adjustments for fuel prices and were designed to increase over time. Customers who did not select a competitive supplier were automatically placed on SOS; new customers were placed on "default service" until they selected a competitive supplier. Beginning in 2001, through the end of the transition period, default service rates reflected market prices.

Customers who do not choose a competitive supplier, now receive "basic service" from the utilities, obtained by the electric distribution companies from third-party suppliers through a competitive bid process reviewed by the DPU. For residential and small commercial customers, each distribution company procures 50% of its basic service supply semi-annually, for 12-month terms. For medium and large commercial and industrial customers, each utility procures 100% of its basic service supply requirement quarterly for three-month terms.

In 2014, the DPU opened an investigation into initiatives to improve the retail electric competitive supply market by: (1) providing customers with information regarding competitive supply products that is accurate, transparent and understandable; and (2) improving customer protections related to the marketing and delivery of competitive suppliers' product offerings. As part of the investigation, the Department established rules for the assignment of customers from one competitive supplier to another competitive supplier and the shopping for competitive supply website (Section updated 2/22/17)

Gas Regulatory Reform/Industry Restructuring

Customer Choice — Between 1993 and 1996, the Department approved the offering of transportation-only service to large commercial and industrial customers; choice of gas suppliers became available to all customers in 2000. DPU rules require that: (1) the local distribution company, or LDC, remains the default service provider; (2) competitive suppliers and marketers be certified by the DPU; and, (3) LDCs provide suppliers/marketers with customer usage data.

The Department allows, but does not require, the LDCs to use financial risk-management instruments to mitigate commodity price volatility. All risk management proposals are subject to review on a case-specific basis. Customer participation in an LDC's financial risk management program must be voluntary, and costs associated with such programs may only be recovered from participants. (Section updated 2/22/17)

Securitization

In 1999, the Department approved NSTAR Electric's application to issue bonds to securitize approximately $800 million of stranded costs, the majority of which were associated with the divestiture of the Pilgrim nuclear plant; $725 million of bonds were issued in 1999. In 2001, the DPU approved Western Massachusetts Electric Company's request to securitize $155 million of stranded costs; the bonds were issued in May 2001. In 2005, the Department authorized NSTAR Electric to issue $675 million of rate reduction bonds related to the buy out of certain purchased power contracts. The bonds were issued in March 2005. (Section updated 2/22/17)

Adjustment Clauses

Fuel/Gas Commodity — Quarterly electric fuel and purchased power adjustments were eliminated in 1998, coincident with the start of retail competition. Electric utilities now offer basic service to customers that are not served by competitive suppliers. Rates for basic service are market-based; such rates reflect the competitive solicitations for basic service supply undertaken by the distribution utility. The utilities are not at risk for fluctuations in market prices. Electric utilities recover the energy-related portion of bad debt cost through their basic service rates.

Cost of gas adjustments, or CGAs, are determined semi-annually based on seasonally-differentiated peak and off-peak costs. Over- and under-recoveries are credited to, or debited against, a deferred gas cost account, and are reconciled by season. Any balance is ultimately passed along or recovered through the CGA factor, with carrying costs. A local gas distribution company, or LDC, must submit an amended gas adjustment whenever the company projects that its deferred gas cost balance will exceed 5% of the total seasonal gas costs.

Capital Investment — A solar cost adjustment tariff was implemented in conjunction with the Department's 2009 approval of Western Massachusetts Electric Company's, or WMECO's, proposal to install 6 MWs of solar energy generation. In 2010, the DPU approved a solar cost adjustment charge for Massachusetts Electric, or ME, for the utility's installation of 5 MWs of solar generation, which was expanded in 2014 and 2016, as approved by the DPU, to recover the costs of additional company-owned solar sites of up to 20 MW and 14 MW, respectively (see the Integrated Resource Planning section).

On April 29, 2016, the DPU adopted a capital cost adjustment mechanism, or CCAM, for Fitchburg Gas and Electric's, or FG&E's, electric division that permits the company to recover costs associated with post-test-year capital additions. The mechanism contains an annual spending cap of $5.7 million and a cap on annual rate increases under the mechanism of 1% of total revenues, with any amounts above the 1% cap to be deferred for future recovery with carrying charges. To the extent that FG&E's capital expenditures exceed the amount it is allowed to recover through its CCAM, the company can seek to include such investment in rate base in its next base distribution rate proceeding.

On Sept. 30, 2016, the DPU authorized the continuation of ME's CCAM that has been in place since 2010 with modifications, including an annual spending cap of $249 million, based on the historical three-year average of capital spending, and changes in the rates under the mechanism subject to a 1% revenue cap.

In accordance with 2014 legislation, each of the state's LDCs files with the DPU a plan, called a "Gas System Safety Enhancement Program,", or GSEP, to address aging or leaking natural gas infrastructure. The related costs/investments may be recovered through a GSEP provision.

The following utilities have GSEP rate mechanisms in place: Berkshire Gas; Boston Gas; Colonial Gas; Liberty Utilities (New England Gas); Bay State Gas; NSTAR Gas; and, FG&E. Previously, some of the state's gas utilities used targeted infrastructure replacement, or TIRF, mechanisms.

Initially, LDCs that seek to participate in the program must file a plan that is designed to remove leak-prone cast iron and unprotected steel piping from the LDC's system over a 20-year period. Participating LDCs must file by each Oct. 1 a list of projects the utility plans to complete during the upcoming construction season, as well as proposed adjustments to distribution rates effective May 1 of the following year that will allow for recovery of program-related costs. The law specifies the criteria that the DPU must apply during its evaluation of the LDC's plan and, if the plan meets those criteria, the Department must approve the plan and the adjusted distribution rates. On or before May 1 of each year during an LDC's program, the LDC must file final documentation for projects completed during the prior year to demonstrate substantial compliance with its plan in effect for that year and that project costs were reasonably and prudently incurred. The LDC's May 1 filing reconciles the estimated costs that were approved for recovery to the actual costs incurred during the year, and adjustments to distribution rates, for recovery or refund, are made accordingly. The ROE authorized in the company's most recent rate case is to be utilized in its GSEP. Annual changes in the revenue requirement eligible for recovery may not exceed 1.5% of the company's most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers. Any revenue requirement approved by the DPU in excess of the cap may be deferred for recovery in the following year.

Local distribution adjustment clauses, or LDACs, are also in place for the LDCs, with changes implemented on a semi-annual basis to reflect recovery of reconcilable gas-distribution-related costs that are not included in base rates. Such expenses include energy efficiency program costs, environmental response costs associated with manufactured gas plants, residential arrearage management programs, low income discounts, pension and post-retirement benefits other than pension costs, the revenue requirement on TIRF and GSEP investment, and attorney general expenses. LDACs are applicable to all firm customers.

Decoupling — In 2008, the DPU ordered all electric and gas utilities to begin phasing in full revenue decoupling mechanisms. Full revenue decoupling mechanisms are in place for BSG, ME, Boston Gas, Colonial Gas, WMECO, Liberty Utilities (New England Gas Company, NSTAR Gas, and for the electric and gas operations of FG&E. These mechanisms include a cap on decoupling adjustments, with any amounts above the cap to be deferred for future recovery, with carrying charges.

Other — Recovery mechanisms for pension and post-retirement benefits other than pensions, or PBOP, are in place for ME, WMECO, NSTAR Electric, NSTAR Gas, FG&E, Liberty Utilities (New England Gas Company, Boston Gas, Colonial Gas, and Bay State Gas. The utilities file annually for recovery of pension and PBOP costs not currently reflected in rates. Such costs are to be recovered through the LDAC reconciliation mechanism for gas utilities and a separate rate component for electric utilities. The electric utilities are permitted to utilize transmission cost recovery mechanisms, and reconciliation mechanisms are in effect for recovery of low-income discounts, arrears forgiven as part of a residential arrearage management program, and administrative costs (e.g., employee costs, bad debt and working capital) incurred in providing basic service.

The DPU has adopted energy efficiency reconciliation factors, or EERF, for the state's electric utilities. The EERF is a fully-reconciling funding mechanism designed to recover the costs associated with the state's electric energy efficiency investments that are in excess of the level collected from other funding sources, including the systems benefits charge, proceeds from the forward capacity market, and proceeds from the Regional Greenhouse Gas Initiative. (Section updated 2/22/17)

Integrated Resource Planning

Electric and gas utilities are required to file energy efficiency plans every three years. The plans, which are reviewed by an Energy Efficiency Advisory Council and approved by the DPU, must include a proposed performance incentive mechanism and a fully-reconciling funding mechanism. The most recent plans were approved in January 2016, for the years 2016, 2017 and 2018 and contain energy savings targets, performance incentive mechanisms, and a cost-recovery framework detailing the funding sources for such investments. Specifically, the funding for the electric plans are to be derived from: a statutory system benefits charge of $0.0025 per KWH billed to ratepayers; proceeds from the forward capacity market; and, proceeds from the Regional Greenhouse Gas Initiative (see the Emissions Requirements section). For budgeted program spending in excess of the aforementioned funding sources, the electric utilities are permitted to implement an energy efficiency reconciliation factor, to provide funding in addition to these other sources (see the Adjustment Clauses section). Gas utilities use energy efficiency surcharges, which are part of their local distribution adjustment clauses. All energy efficiency rates are based on each year's budget contained in the three-year energy efficiency program budget.

Utilities are permitted to own solar electric installations with total capacity aggregating to up to 35 MW with DPU approval and recover the costs associated with the facilities in rates. In 2009, the DPU approved Western Massachusetts Electric Company's, or WMECO's, proposed installation of 6 MWs of solar energy generation, which was subsequently expanded to 8 MWs with DPU approval in 2013. The solar facilities were commissioned beginning in 2010, and a 9% equity return was applied to such assets. WMECO's solar investment is being recovered through a solar cost adjustment charge. In December 2016, the DPU approved WMECO's and NSTAR Electric's request to own 27 MWs and 35 MWs of solar generation to be constructed during 2017. The ROE to be authorized in the pending rate cases for NSTAR Electric and WMECO, in which new rates will become effective Jan. 1, 2018, will be applied to the new solar investments.

In 2009, the DPU approved Massachusetts Electric's, or ME's, proposal for the installation and recovery of 5 MW of solar investment across five sites in its service territory. The DPU approved recovery, beginning in 2010, of ME's first solar generation facility, and approved three additional sites in 2011, and one final site in 2012. The DPU approved ME's request to own, construct and operate up to an additional 20 MW in 2014, and an additional 14 MW on Dec. 29, 2016. The equity return applied to ME's solar investment is the ROE currently authorized in the company's last rate case.

In November 2016, the DPU approved Fitchburg Gas and Electric's proposed installation of 1.3 MW of solar generation.

Construction of the facilities is expected to be completed by the end of November 2017.

In 2014, the DPU issued orders requiring the state's electric distribution utilities to develop and implement a 10-year grid modernization plan, or GMP, outlining how the company proposes to make "measureable progress" towards: (1) reducing the effects of outages; (2) optimizing demand (including reducing system and customer costs); (3) integrating distributed resources; and, (4) improving workforce and asset management. In addition, a company's GMP must include a marketing, education, and outreach plan.

Electric utilities filed their first GMPs in August 2015. The plans, which are under review by the DPU, include a five-year short-term investment plan, or STIP, which would apply only to a company's capital investments. A company's STIP must include a plan for achieving "advanced metering functionality" within five years of the Department's approval of the GMP. Capital investments included in the STIP must be supported by a comprehensive business case analysis. If that analysis does not justify deployment of advanced metering functionality within five years, the company may include an alternative proposal to achieve that functionality within a longer timeframe, together with a business case analysis that justifies the alternative. The DPU's order allows for the utilization of cost recovery mechanisms for incremental capital investments included in the STIP. To be eligible for targeted cost recovery, investments associated with advanced metering functionality must be: (1) pre-authorized by the DPU; (2) made within five years of approval of a company's GMP; (3) incremental relative to the company's current investment practices, i.e., accelerate achievement of the grid modernization goal; and, (4) prudently incurred. The utilities are to update their GMPs in subsequent distribution base rate case, which by statute must occur no less than every five years. Updates are to: describe the GMP implementation to date; report on the progress relative to developing and meeting metrics; describe changes to the GMP; and, include a new ten-year GMP. A utility may amend its GMP in between rate case filings.

The utilities in Massachusetts have transferred operational control of their transmission assets to ISO New England, an independent, non-profit Regional Transmission Organization, or RTO, serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. A division of ISO-NE, the New England Power Pool, and the predecessor to the ISO-NE, in August 2016, launched a stakeholder process, referred to as Integrating Markets and Public Policy, or IMAPP, that seeks to identify and explore potential changes to the wholesale power markets that could be implemented to advance state public policy objectives in New England. (Section updated 2/22/17)

Renewable Energy

Legislation enacted in 2008 and modified in 2012 directs electric distribution utilities to enter into long-term contracts with renewable energy developers (see the Integrated Resource Planning section). The law specifies a two-tiered RPS standard under which retail electric suppliers are required to obtain renewable power from Class I resources equal to 4% of KWH sales in 2009, rising to 15% in 2020, to 25% in 2030, and increasing 1% each year thereafter. Class I resources include new or incremental renewable energy generating sources that begin commercial operation after Dec. 31, 2007, or incremental generating capacity after Dec. 31, 1997, at an existing facility, that generates electricity from: (1) solar photovoltaic or solar thermal electric energy; (2) wind energy; (3) ocean or tidal energy; (4) fuel cells utilizing renewable fuels; (5) landfill gas; (6) energy generated by new hydroelectric facilities, or incremental energy from increased capacity at existing hydroelectric facilities; (7) low-emission advanced biomass power conversion technologies using fuels such as wood, by-products or waste from agricultural crops, food or animals, energy crops, biogas, liquid biofuel, organic refuse-derived fuel, or algae; (8) marine or hydrokinetic energy; or, (9) geothermal energy. A portion of the required renewable energy under Class I must come from in-state solar facilities —1,600 MW of solar is required by 2020.

Class II resources include existing renewable generation that began commercial operation before Dec. 31, 1997, and generate electricity from the same sources as Class I resources, except that hydroelectric facilities would be limited to those up to 7.5 MW and waste energy systems would be limited to state-approved facilities.

In addition to the Class I and Class II renewable portfolio standards, an alternative energy portfolio standard, or AEPS became effective Jan. 1, 2009. The AEPS required that 0.75% of the state's electric load be provided from "alternative energy" generating sources by Dec. 31, 2009, with the percentage to increase to 5% by 2020. The alternative energy sources include: gasification with capture and permanent sequestration of carbon dioxide; combined heat and power; flywheel energy storage; facilities utilizing paper-derived fuel sources; energy efficient steam technology; or, any other alternative energy technology approved by the DOER, excluding coal, that is not used in gasification, petroleum coke that is not used in gasification, oil, or natural gas that is not used in gasification or combined heat and power; and, nuclear power.

Net metering has been available to customers in Massachusetts since the 1980s.

Under state law, each distribution company is required to maintain separate net metering caps for government and business and private sector net metering facilities. Each cap is equal to a percentage of each company's highest historical peak load, which is the most electricity consumed by the distribution company's customers at any one time.

Legislation enacted in April 2016, raised the caps on net metering for local governments to 8% from 5% of a distribution company's peak load and raises the cap for business and private sector installations to 7% from 4%.

On August 8, 2016, House Bill 4568 was enacted requiring the state's electric distribution companies to jointly solicit and enter into long term contracts to procure 1,600 MWs of offshore wind power by June 30, 2027. Each solicitation must be for a minimum of 400 MW and each subsequent solicitation must occur within 24 months of the previous solicitation. The first solicitation is to commence by June 30, 2017. In addition, the utilities are to enter into long term contracts to jointly solicit and procure 9.45 twh of clean energy generation annually, including large-scale hydropower. The first solicitation must commence by April 1, 2017, with the full obligation to be completed by Dec. 31, 2022.

All contract terms are to be between 15 and 20 years, and are subject to DPU approval. Under the law, distribution companies are to receive "remuneration" of up to 2.75% percent of the annual payments under long term contracts for offshore wind energy and clean energy generation for financial obligation of long-term contracts.

In addition, HB 4568 contains provisions with respect to energy storage. Under the law, distribution companies would be permitted to own energy storage systems. The law requires DPU regulations implementing the competitive procurement programs to allow offshore wind energy generation resources and clean energy generation "to be paired with energy storage systems." In accordance with the law, on Dec. 27, 2016, the Massachusetts Department of Energy Resources, or DOER, announced that it is prudent to establish targets for the procurement of energy storage resources by distribution companies. The DOER is to adopt such targets by July 1, 2017. Initial procurement targets would need to be met by January 1, 2020 and would be reevaluated not less than once every three years. (Section updated 2/22/17)

Emissions Requirements

State law requires greenhouse gas, or GHG, emission reductions of 25% versus 1990 levels by 2020, and 80% below 1990 levels by 2050. The DEP has adopted regulations regarding the reporting and verification of statewide GHG emissions and monitors and enforces compliance.

Massachusetts is part of the Regional Greenhouse Gas Initiative, or RGGI, a cooperative effort by certain Northeast and Mid-Atlantic states to reduce greenhouse gas and power-related emissions. The law requires that 80% of any RGGI auction proceeds be allocated to energy efficiency/demand response programs. The remainder of auction proceeds is to be potentially earmarked for municipalities with power plants, community energy programs and voluntary green power development.

In August 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. For Massachusetts, the plan requires an 18% reduction. Many states have challenged the legality of the rule, however, Massachusetts has joined a coalition of 18 states in support of the CPP. The CPP has been stayed by the U.S. Supreme Court, pending the outcome of a review by U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. The CPP litigation has been fully briefed before the D.C. Circuit and a ruling is expected in early 2017. The Supreme Court would be expected to take up the matter shortly thereafter. However, regardless of the pending judicial outcome, the Trump administration could take a number of actions that would rescind the CPP or significantly alter its impact. (Section updated 2/22/17)

Reliability Issues

By statute, electric and gas utilities may be subject to a maximum penalty equal to 2.5% of transmission and distribution revenues for poor service quality, or SQ, metrics related to customer service and billing performance, customer satisfaction, restricted work days, and reliability. A utility is subject to penalties if its SQ performance average falls outside its upper threshold, which is derived from its historical benchmark.

Legislation enacted in 2012 provides for any penalty levied by the DPU to be credited to the affected customers of the penalized company based upon the KWHs used by the affected customer. The law requires the utilities to establish continuous communications with customers during major storms and to coordinate with the Massachusetts Emergency Management Agency and municipalities when implementing an emergency-response plan. The law also established a DPU Storm Trust Fund and requires the utilities to pay an assessment charge to fund the trust.

In 2012, the DPU ordered Massachusetts Electric, or ME, NSTAR Electric, and Western Massachusetts Electric Company, or

WMECO, to pay fines to ratepayers in connection with its findings that the utilities' responses to certain storms were deficient. Specifically, the DPU assessed penalties of $18.7 million for ME, $4.1 million for NSTAR Electric, and $2 million for WMECO. The DPU concluded that the companies failed in their obligations to respond to local public safety officials regarding downed wires. With respect to the recovery of storm costs, the DPU indicated that since ME, NSTAR Electric, and WMECO failed to implement their emergency response plans, the lengths of the service interruptions or outages were materially longer than should have been the case, and therefore, the Department may "deny the recovery of all, or any part of, the service restoration costs." The companies each filed appeals with the Massachusetts Supreme Judicial Court, or SJC, and in 2014, the SJC vacated $2 million of the $4.1 million penalties imposed on NSTAR Electric. In addition, the SJC found that certain of the penalties were not supported by substantial evidence. The remaining penalties for NSTAR Electric, as well as the $2 million in penalties related to WMECO, were upheld. The SJC affirmed all but two violations for ME, reducing the penalty by about $0.9 million.

In 2014, the DPU directed the state's electric distribution utilities to develop and implement 10-year grid modernization plan (see the Integrated Resource Planning section). The plans have been submitted and are currently under DPU review. (Section updated 2/22/17)

Rate Structure

The Department has determined that the goals of designing utility rate structures are to achieve efficiency, simplicity, continuity of rates, fairness between rate classes, and corporate earnings stability.

Legislation enacted in 2012 requires the DPU to design all base rates using a cost-allocation method that produces equalized rates of return for each customer class. However, if employing this cost-allocation method results in a rate increase that is more than 10% for any customer class, as measured on a total bill basis, the DPU is to phase in the elimination of any cross subsidies between rate classes on a revenue-neutral basis.

In June 2014, the DPU issued an order on "time varying" rates, or TVR, requiring electric utilities to set prices for basic service, i.e., default energy supply service available to customers that do not chose to buy energy from a competitive supplier, that take into account the varying costs of electricity and allow customers to make informed decisions on their electricity use throughout the day. The order requires the electric utilities to offer basic service customers: (1) a default time of use rate with a critical peak price component; and, (2) the opportunity to opt out of the default rate and choose a flat rate with a peak time rebate component. The time-of-use rate will be higher during certain hours of each day when wholesale energy prices rise, than during the other hours when electricity usage and wholesale prices are lower. In August 2015, the state's electric utilities filed their initial grid modernization plans, which all included several TVR options. These plans are under review by the DPU.

Legislation enacted in April 2016 permits electric distribution companies to adopt a "monthly minimum reliability contribution" for net metering customers, subject to DPU approval, once the state reaches 1,600 MW in aggregate installed solar capacity. Any such minimum contributions are to ensure that all customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system. Proposals are to be filed in a rate case or in a revenue-neutral rate design filing that is supported by appropriate cost of service data across all rate classes. The law indicates that the DPU may approve a monthly minimum reliability contribution that: equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; does not excessively burden ratepayers; does not unreasonably inhibit the development of Class I, Class II, and Class III renewable facilities; and, is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance and safety of the electric distribution system.

In a rate case decision decided on Sept. 30, 2016 for Massachusetts Electric and Nantucket Electric, the DPU rejected the companies' requests to: impose access fees on "stand-alone", i.e., distributed generation, or DG facilities; utilize tiered customer charge structures for residential and small business rate classes; and, modify demand charges for large commercial and industrial customers. The DPU stated that it is "not persuaded that a cost-shift from DG customers to non-DG customers, in fact, exists" as purported by the companies. (Section updated 2/22/17)

General Information

Contact Information	21 South Fruit Street Suite 10 Concord, NH 03301-2429 (603) 271-2431
	http://www.puc.state.nh.us
Number of Commissioners	3 of 3
Selection Method	Commissioners: Gubernatorial appointment Chairperson: Gubernatorial appointment
Term of Office	Commissioners: 6 years Chairperson: 6 years
Chairperson of Commission	Martin Honigberg
Deputy Chairperson of Commission	NA
Governor	Christopher T. Sununu (R)
Service Regulated	Electric utilities, Gas utilities, Pipeline companies, Sewer utilities, Steam utilities, Telecommunications utilities, Water utilities
Commission Ranking	Average/3 (1/1/2002)
Commmission Budget	$8.50 million
Commissioner Salaries	Commissioners: $82,800 - $110,000 Chairperson: $93,800 - $124,600
Size of Commission Staff	75
Company Name, Abbreviated	New Hampshire Public Utilities Commission's Rate Case History
Research Notes	RRA Articles
RRA Contact	Lisa Fontanella

Commissioners

Person's Name	***Party Abbreviation***	***Date Role Began***	***Term Ends***
Martin Honigberg Chairman	D	01/2014	06/2019
Kate Bailey		07/2015	06/2021
Michael Giaimo		07/2017	06/2023

RRA Ranking History

Date of Ranking Change	***Commission Ranking***
1/1/2002	Average / 3
2/28/1997	Below Average / 2
7/10/1996	Below Average / 1
7/14/1995	Average / 2

Date of Ranking Change	Commission Ranking
4/4/1984	Average / 2
7/2/1982	Above 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

Commissioner Selection Criteria — Commission appointments are subject to confirmation by the Executive Council. The Executive Council consists of five members elected in a general election, each representing a Council district. Usually no more than two commissioners are from the same political party, but minority party representation is not required. At least one commissioner must be an attorney, and one must have a background and/or experience in engineering, economics, accounting, or finance. The chairman is designated by the governor for the full six-year term as commissioner.

Commissioner Membership— Commissioners may continue to serve for no more than six months beyond the ends of their terms, pending reappointment or replacement.

Staff Contact: Debra A. Howland, Executive Director (603) 271 2431

(Section updated 12/8/17)

RRA Evaluation

New Hampshire regulation is somewhat restrictive from an investor perspective. While many of the rate proceedings before the PUC in recent years have been resolved via settlements, in some instances, the stipulated equity returns have been somewhat below the prevailing industry averages when established. Earnings sharing mechanisms are in place for certain energy utilities that provide for incremental earnings above a benchmark equity return to be shared with customers. While retail competition is in place for electric generation service, Public Service Company of New Hampshire, or PSNH, continues to provide generation service to non-switching customers, with the power to meet these obligations obtained from a combination of company-owned assets and purchased power contracts. However, a PUC approved settlement provides for the divestiture of the company's generation assets and ultimate issuance of bonds for the securitization of stranded costs following the sale of the plants. The plants are expected to be sold in the near future. Currently, PSNH recovers its power costs through a periodically-adjusted default service rate that reflects the revenue requirements of its generating assets and the cost of power purchases. The state's other electric utilities procure default energy service for their customers through the issuance of requests for proposals. There is little natural gas service in the state, but the PUC has adopted automatic commodity cost recovery provisions for the few small gas distribution companies. At this time, the state's utilities are permitted to utilize lost revenue adjustment mechanisms, there are no full decoupling mechanisms in place. RRA continues to accord New Hampshire an Average/3 rating. (Section updated 12/8/17)

Commission Staff

Approximately 75 members selected through, and protected by, the State Civil Service System. There are also three unclassified staff members serving as general counsel, executive director, and director of safety and security. (Section updated 12/8/17)

Consumer Interest

The Office of the Consumer Advocate is responsible for representing residential ratepayer interests. The consumer advocate is appointed by the governor and Executive Council for a four-year term. The current consumer advocate, Donald Kreis, is serving a term extending to Nov. 5, 2019. (Section updated 12/8/17)

Rate Case Timing/Interim Procedures

If the PUC has not acted upon a general rate increase request within six months following the proposed effective date, which is generally 30 days after the date of filing, the utility may place the requested increase into effect, under bond. If the commission has not issued a final decision within one year of the proposed effective date, the increase becomes permanent. Temporary increases may be granted if a utility demonstrates that it is not currently earning a reasonable return. State statutes permit the reconciliation of temporary rates with permanent rates, and for the most part, permanent rates are reconciled back to the effective date of temporary rates. In recent years, temporary rate increases have generally been granted when requested. (Section updated 12/8/17)

Rate Base and Test Period

While in the past the PUC has utilized a 13-month average or a five-quarter average rate base, recent rate cases have utilized a year-end rate base. The commission uses a historical test year, adjusted for known-and-measurable changes. State statutes prohibit the inclusion of construction work in progress in rate base. (Section updated 12/8/17)

Return on Equity

While many of the rate proceedings before the PUC in recent years have been resolved via settlements, in some instances, the stipulated equity returns have been somewhat below the prevailing industry averages when established. In an electric rate case for Unitil Energy Systems, or UES, decided on April 20, 2017, the PUC adopted a settlement that specified a 9.5% ROE for delivery service. UES is a subsidiary of Unitil Corporation. On April 12, 2017, the PUC adopted a 9.4% ROE for Liberty Utilities (Granite State Electric) Corp., whose ultimate parent is Algonquin Power & Utilities.

In 2010, the PUC adopted a settlement that specified a 9.67% ROE for Public Service Company of New Hampshire's, or PSNH's, distribution service and contained an earnings sharing mechanism. For further details, see the Alternative regulation section. PSNH is authorized a 9.81% ROE that was established in 2007 for its fossil/hydro generation assets that are used for default energy service. See the Electric regulatory reform/industry restructuring section for further details. PSNH, doing business as Eversource Energy, is a subsidiary of Eversource Energy.

The most recent ROE determination for a gas company occurred in 2014, when the PUC adopted a 9.5% ROE for Unitil Corporation subsidiary Northern Utilities following a settlement. In 2009, the PUC adopted a 9.54% ROE for Liberty Utilities (EnergyNorth Natural Gas), whose ultimate parent is Algonquin Power & Utilities. (Section updated 12/8/17)

Accounting

Major storm reserve accounts are utilized by the state's electric utilities. (Section updated 12/8/17)

Alternative Regulation

A multi-year distribution rate plan was in effect for Public Service Company of New Hampshire, or PSNH, for the five-year period July 1, 2010 through June 30, 2015. Under the plan, 75% of earnings above a 10% ROE was to be allocated to customers. As part of a settlement regarding the divestiture of PSNH's generation assets, the company has agreed to maintain existing base rates through July 1, 2017. T

Liberty Utilities (Granite State Electric) Corp. is operating under the terms of an April 2017 PUC-approved electric rate plan that allows for step adjustments on May 1, 2018, and May 1, 2019. If the company were to file a rate case at the conclusion of the rate plan, on May 1, 2019, based on the PUC's typical rate case timeframe, the earliest new rates could take effect would be in January 2020

Unitil Energy Systems is operating under the terms of an April 2017 PUC-approved electric rate plan that allows step adjustments on May 1, 2018, and May 1, 2019. UES is to refrain from filing a rate case prior to Jan. 1, 2020, unless its distribution ROE is less than 7% for a reporting calendar year. Based on the PUC's typical rate case timeframe, the earliest new rates could take effect would be in January 2021.

As part of a settlement adopted by the PUC in 2007, in connection with the National Grid and KeySpan Corporation merger, former KeySpan subsidiary Liberty Utilities (EnergyNorth Natural Gas), is subject to a mechanism until at least Aug. 31 2017, whereby the company is to share equally with ratepayers any merger-related savings. An ESM is to become effective beginning in August 2017, under which the company will be required to share equally with ratepayers any incremental earnings above its authorized ROE.

The state's electric and gas utilities are permitted to earn incentive payments for meeting certain energy efficiency goals. (Section updated 12/8/17)

Court Actions

PUC decisions may be appealed directly to the New Hampshire Supreme Court. Judges are nominated by the governor and confirmed by the Executive Council. On Feb. 10, 2017, the Court rejected an appeal of the PUC's November 2016 order establishing the auction process for the divestiture of Public Service Co. of New Hampshire's, or PSNH's, generation assets. The appellants had alleged that the auction process and schedule were unreasonable. The formal divestiture process is underway, buyers have been chosen and the company intends the asset sale to be completed by the end of 2017. See the Electric regulatory reform/industry restructuring section for further details. Pending before the Supreme Court are appeals filed on Jan. 9, 2017 by PSNH and Algonquin Gas Transmission of an October 2016 decision in which the PUC ruled that it did not have the statutory authority to approve contracts for natural gas pipeline capacity and storage. (Section updated 12/8/17)

Legislation

The New Hampshire General Court, a bicameral body, consisting of the House of Representatives and the Senate, convenes annually in January for a minimum 45-legislative-day session. The House is comprised of 400 members—170 Democrats, 220 Republicans, three Libertarians and seven vacancies. The Senate is comprised of 10 Democrats and 14 Republicans. The 2017 session convened on Jan. 4 and adjourned on June 30.

Several energy measures were signed into law in 2017. SB 125, enacted June 2, 2017, establishes a five-member committee to study transmission, distribution, generation and other costs in the state's electricity system.

SB 129, enacted without the governor's signature on July 13, 2017, increases the solar Class II renewable portfolio standard requirements to 0.5% in 2018, 0.6% in 2019 and 0.7% in 2020 and beyond, and requires a portion of the renewable energy fund to benefit low to moderate income residential customers. For further details, see the Renewable energy section.

SB 51, which was signed into law on June 2, 2017, establishes a committee to study subsidies for energy projects provided by the renewable portfolio standard. The committee is report its findings and recommendations by Nov. 1, 2017.

HB 518, which would lower the net energy metering rates to the average monthly wholesale prices, as determined by ISO-New England, was retained in committee. In addition, HB 317, legislation which would have prohibited the PUC from increasing the system benefits charge without legislative approval was retained in committee. Also, legislation that would have required the state to withdraw from the Regional Green House Gas Initiative, or RGGI, a multi-state effort to cap greenhouse gas emissions from power plants, was retained in committee.

HB 225, legislation that would have repealed the state's renewable portfolio standard, was not enacted.

The 2018 legislative session is expected to convene on Jan. 3. (Section updated 12/8/17)

Corporate Governance

The PUC has authority over mergers involving utilities and utility holding companies, and has required certain ring-fencing provisions in the context of merger approvals. See the Merger activity section for further details. The PUC also has authority over corporate reorganizations. In addition, the commission must approve a utility's issuance of common or preferred stock and long-term debt, as well as the total level of short-term debt that may be outstanding. (Section updated 12/8/17)

Merger Activity

There are two statutory provisions that detail the PUC's authority over mergers or acquisitions of New Hampshire public utilities. Under one provision, approval of the commission "shall not be required if the public utility files with the commission a detailed representation in writing no less than 60 days prior to the anticipated completion of the transaction that the transaction will not have an adverse effect on rates, terms, service, or operation of the public utility within the state." The PUC has indicated that this provision "is designed to allow for streamlined review of transactions that clearly will have no such adverse impacts." Under this procedure the statute specifies a series of timelines designed to allow the transaction to go forward if it meets the “no adverse effect” test. Specifically, an acquisition is deemed to be approved if the commission does not issue an order within 60 days of the filing, subject to various extensions and findings. If the commission finds an adverse effect, the petitioner is afforded an opportunity to amend its filing, and the commission is then required under the statute to review the filing “under the statute that would have otherwise applied but for this section” within 180 days of the filing of the initial petition.

Under another provision, no public utility or public utility holding company may acquire a controlling interest, defined as more than 10% in a public utility operating company incorporated or doing business in New Hampshire without prior PUC approval?. State statutes specify that the transaction must meet certain standards for PUC approval, including that the transaction "will not have an adverse effect on rates, terms, service, or operation of the public utility within the state" and is "lawful, proper and in the public interest."

In 1999, the PUC approved the proposed merger of then-Granite State Electric, or GSE, parent New England Electric System, or NEES, and National Grid Group. The merger was completed in 2000, and as a result, NEES' corporate name is now National Grid USA.

In 2000, the PUC approved the proposed merger of PSNH then parent Northeast Utilities and Consolidated Edison. The commission's order, which adopted a settlement, was conditioned upon Consolidated Edison forming separate regulated and unregulated service companies. The merger was never consummated.

In 2000, the PUC approved the proposed merger of NiSource and Columbia Energy Group. The merger closed in late-2000. Northern Utilities, a local gas distribution company in New Hampshire, became a subsidiary of NiSource subsidiary Bay State Gas. Following a subsequent transaction, Northern Utilities was acquired by Unitil Corporation, as discussed below.

Effective Dec. 1, 2002, then-Unitil Corp. subsidiaries Concord Electric Company and Exeter & Hampton Electric Company merged into a single company, Unitil Energy Systems, or UES. Coincident with the formation of the new entity, UES implemented a $2 million distribution rate increase.

In 2003, the PUC approved PSNH's acquisition of Connecticut Valley Electric Company's, or CVEC, electric system. CVEC had been a subsidiary of Central Vermont Public Service, or CVPS. PSNH paid CVPS approximately $9 million for CVEC's assets, and an additional $21 million for the termination of a wholesale power contract between CVPS and CVEC. As part of the agreement, PSNH was authorized to recover, over the next three to four years, the $21 million payment as part of its stranded costs.

In 2000, the PUC approved the acquisition of EnergyNorth by Eastern Enterprises following a settlement that provided for then EnergyNorth subsidiary EnergyNorth Natural Gas customers to receive a 2.2% rate reduction. Recovery of merger-related costs was to be considered by the PUC to the extent the companies demonstrated that the customer benefits of the merger equaled or exceeded the amount proposed for amortization. KeySpan Corporation subsequently acquired Eastern Enterprises and its EnergyNorth subsidiary, and in 2007, KeySpan was acquired by National Grid, as discussed below.

In 2007, following PUC approval of a related settlement, National Grid acquired KeySpan, then the parent of EnergyNorth Natural Gas. The settlement and PUC order outlined a five-year rate plan for then National Grid subsidiary GSE that was in effect from Jan. 1, 2008 through Dec. 31, 2012. Under the plan, GSE implemented $2.2 million in rate reductions. National Grid was required to utilize an imputed capital structure of 50% debt and 50% equity with a 9.67% return on equity and an 8.61% overall return, until adjusted by the PUC in a subsequent case. Also, the plan included an earnings sharing mechanism. Electric distribution rate increases requested during the plan were limited to reflect exogenous events and certain other issues, and a storm reserve fund was established. The company agreed to forego recovery of the acquisition premium.

In any base rate filing occurring before Aug. 31, 2017, EnergyNorth Natural Gas was required to use an imputed capital structure of 50% equity and 50% debt. A mechanism is in effect to allow the company to retain 50% of any proven merger-related savings for a period of up to 10 years following the merger. The company is precluded from recovering the merger acquisition premium. An earnings sharing mechanism became effective beginning in August 2017, under which the company is to share equally with ratepayers any incremental earnings above its then-authorized ROE.

In 2012, the PUC approved Liberty Energy Utilities New Hampshire's proposed purchase of National Grid USA's New Hampshire subsidiaries GSE and EnergyNorth, following a settlement. The ultimate parent of Liberty Energy is Algonquin Power & Utilities. Under the provisions of the approved settlement: (1) GSE and EnergyNorth are to issue long-term debt in an amount sufficient to establish a capital structure of 45% debt/55% equity; (2) GSE and EnergyNorth are to record a regulatory asset or liability equal to the amount necessary to reflect the fair value of its pension and other post- employment benefits obligations; (3) GSE was required to refrain from filing a rate case with a proposed effective date prior to Jan. 1, 2013; (4) EnergyNorth is to refrain from filing a rate case until the earlier of three years from the date of closing or 270 days after the date on which 70% of the transition service fees are paid; (5) The acquisition premium and the transaction or transition costs are not recoverable in rates; and, (6) Recovery of rate case expenses will be limited in the first rate case following closing of the transaction for both EnergyNorth and GSE. The transaction closed in July 2012, and GSE and EnergyNorth have been renamed Liberty Utilities (Granite State Electric) and Liberty Utilities (EnergyNorth Natural Gas).

In 2011, the PUC ruled that it lacked jurisdiction over the proposed merger of Northeast Utilities and NSTAR. The merger closed in 2012, and after a rebranding effort that commenced in 2015, the company is now known as Eversource Energy.

In 2012, the PUC approved Gaz Métro Limited Partnership's proposed acquisition of CVPS. The PUC's authority over the transaction stemmed from CVPS' ownership of interests in certain transmission assets in the state.

In 2007, the PUC approved Iberdrola's proposed acquisition of Energy East. The transaction was completed in 2008, and Energy East propane subsidiary New Hampshire Gas Corp. became a subsidiary of Iberdrola. The PUC adopted the terms of a settlement that prohibits the companies from recovering any transaction costs or acquisition premium from ratepayers.

In 2008, the PUC approved Unitil Corp.'s proposed acquisition of Northern Utilities from NiSource, following a settlement. The transaction was completed in late-2008. Under the provisions of the approved settlement, Unitil was to: refrain from filing a base rate case before Nov. 1, 2010, and is to forego recovery of any acquisition premium resulting from the transaction; flow all savings from the transaction to ratepayers in its subsequent base rate case; and, provide access to the books and records of any Northern Utilities' affiliates.

In 2014, the PUC approved Liberty Utilities (EnergyNorth Natural Gas) Corp.'s acquisition of New Hampshire Gas Corp., a propane company, from Iberdrola. As part of the acquisition, Liberty Utilities (Energy North Natural Gas) was required to separately account for the new company and to keep its operations largely independent of its existing business.

On Oct. 13, 2017, the PUC found that of Eversource Energy's proposed acquisition of Macquarie Utilities Inc. and its subsidiaries, including Aquarion Water passed the "no adverse effect" test, and therefore PUC review of the transaction was not required. According to the PUC, "it has no basis to find that Eversource's acquisition of Aquarion's parent company will have an adverse effect on rates, terms, service, or operation of Aquarion within the state." The PUC noted that it "has continuing jurisdiction over the subsidiaries and will monitor the effects of the merger in accord with its statutory responsibilities." Assuming all regulatory approvals are forthcoming, the merger is expected to close by Dec. 31, 2017. (Section updated 12/8/17)

Electric Regulatory Reform/Industry Restructuring

State law required implementation of retail choice for all electric customers in 1998. However, due to litigation that followed the PUC's 1997 approval of a restructuring plan for Public Service Company of New Hampshire, or PSNH, retail access was not implemented statewide until 2001. Securitization of certain stranded costs was permitted. For further details, see the Securitization section.

PSNH continues to provide default energy service to customers who do not select a competitive supplier. The output of the generation assets retained by PSNH must be used to meet default service requirements. PSNH's default service rate is designed to recover generation and purchased power costs, including a return on its generation assets. Any difference between default energy service revenues and actual costs incurred are deferred for future recovery or refund.

PSNH retained its 1,200 MW of fossil and hydro assets, but divested its nuclear assets. In 2002, eight joint owners, including PSNH, with interests totaling 88.2%, or 1,024 MWs, sold their ownership shares of the Seabrook nuclear plant to what is now NextEra Energy for $836.6 million. The net gain from the sale of affiliate North Atlantic Energy Corp.'s share was used by PSNH to reduce stranded costs. PSNH was prohibited from selling its remaining generation assets without prior PUC approval; however, a divestiture process is currently underway and discussed below.

PSNH generation divestiture

In 2014, in accordance with legislation enacted that same year, the PUC commenced a proceeding to determine whether some or all of PSNH's generation assets should be divested or retired. Enabling legislation was enacted in 2015, allowing for the utilization of securitization financing to recover any stranded costs resulting from the sale of the plants.

In July 2016, the PUC adopted a settlement that provides for the divestiture of PSNH's fossil and hydroelectric generation facilities and instructed the company to begin the process to divest its generation assets. The approved settlement also provides for PSNH to forego recovery of $25 million of the equity return related to the company's clean air project. In addition, as part of the approved settlement PSNH agreed to not seek a distribution rate increase effective before July 1, 2017 and is to contribute $5 million to create a clean energy fund, which will not be recoverable from its customers.

In November 2016, the PUC established a process of auctioning of the plants that was managed by J.P. Morgan. Various parties appealed that PUC ruling, but on February 10, 2017, the New Hampshire Supreme Court upheld the PUC decision. On Oct. 12, 2017, PSNH filed for PUC approval to divest its generation asset portfolio to two buyers, comprised of a joint venture and a private equity firm, for $258 million, under the process outlined by the PUC. On Nov. 28 and Nov. 29, the PUC approved the sales; the sales are expected to be completed by late-December 2017.

Liberty Utilities (Granite State Electric) Corp. and Unitil Energy Systems sold all their generation assets as part of their restructuring agreements. These distribution-only companies supply default energy service through a request-for-proposals process supervised by the PUC. (Section updated 12/8/17)

Gas Regulatory Reform/Industry Restructuring

Since 1993, gas retail choice has been available for the commercial and industrial customers of the state's two local distribution companies, Northern Utilities and Liberty Utilities (EnergyNorth Natural Gas) Corp. No action has been taken with regard to offering retail choice to residential customers. (Section updated 12/8/17)

Securitization

In conjunction with electric industry restructuring, the PUC authorized Public Service Company of New Hampshire, or PSNH, to issue up to $670 million of bonds to securitize a portion of the company's stranded costs. In 2001, PSNH issued $525 million of such bonds, which matured in 2013, and in 2002 issued an additional $50 million of bonds, which matured in 2008.

Legislation was enacted in 2015 that permits the PUC to issue a new financing order authorizing the issuance of securitization bonds to finance stranded costs resulting from a PUC–approved divestiture of all or some of PSNH's, generation assets. The legislation comports with a PUC-approved settlement on this issue. See the Electric regulatory reform/industry restructuring section for further details. The law authorizes the issuance of bonds in an amount sufficient to fund stranded costs, deferrals, transaction costs, tax liabilities, employee protections, payments in lieu of taxes, and other expenditures. The PUC is reviewing PUC's financing order associated with the asset sale. (Section updated 12/8/17)

Adjustment Clauses

Fuel and purchased power adjustment clauses, or FPPACs, had been utilized prior to the implementation of retail choice in the early 2000s. Public Service Company of New Hampshire, or PSNH, now recovers its power costs through a periodically-adjusted default service rate, which reflects the revenue requirements of its generating assets and the cost of power purchases. It also includes a reconciliation of the difference between the company's costs and revenues for the previous period.

A transmission cost adjustment mechanism, or TCAM, is also in place for PSNH. The TCAM, which is designed to provide recovery of all transmission-related costs, is adjusted annually each July 1.

Reliability enhancement and vegetation management programs are in effect for PSNH, Liberty Utilities (Granite State Electric), and Unitil Energy Systems. The programs provide for recovery of both the capital investment and increases to O&M expenses necessary for ongoing system reliability and vegetation management efforts.

Cost-of-gas adjustment mechanisms are permitted. The local gas distribution companies may adjust their charges for commodity costs by up to 25%, without prior PUC approval. For Liberty Utilities (EnergyNorth Natural Gas) Corp.'s and Northern Utilities' customers, the PUC has approved gas-cost hedging and a fixed-price option, whereby customers may lock in a price for the winter period. A cast iron/bare steel rate adjustment mechanism is in effect for Liberty Utilities (EnergyNorth Natural Gas) Corp.

The PUC has concluded that revenue decoupling mechanisms should only be implemented on a company-specific basis in the context of a full rate case. In 2011 and 2015 rate cases, Liberty Utilities (EnergyNorth Natural Gas) Corp. had requested a revenue decoupling mechanism; however, the PUC adopted settlements in those proceedings that did not include such a mechanism. Legislation was enacted in 2015 that established a commission to investigate the implementation of revenue decoupling mechanisms for New Hampshire's electric and gas utilities. The legislation calls for the commission to: (1) review other states' decoupling legislation and procedures; (2) review the PUC's past dockets related to decoupling; (3) determine whether or not decoupling would result in increased energy efficiency in the state; (4) determine whether or not decoupling is the best mechanism to achieve greater energy efficiency for both utilities and consumers; and, (5) determine the optimal decoupling approach to best meet the needs of New Hampshire utilities and consumers, taking into consideration rate or bill impacts, improvements in utility bill stability, cost shifting, incentives and other related issues.

In August 2016, the PUC established an energy efficiency resource standard, or EERS, for New Hampshire's electric and gas utilities. The EERS is to become effective Jan. 1, 2018. The utilities implemented lost revenue adjustment mechanisms, or LRAMs, effective Jan. 1, 2017, to recover lost revenue due to the installation of energy efficiency measures. Total recovery through the LRAM is capped at 110% of planned annual savings. The PUC ordered the utilities to seek approval of a decoupling mechanism or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before. Liberty Utilities is seeking a decoupling mechanism as part of its pending natural gas rate case. (Section updated 12/8/17)

Integrated Resource Planning

Pursuant to state law, electric and gas utilities are required to file a least-cost integrated resource plan, or IRP, with the PUC within two years of the commission's final order regarding the utility's prior plan, and in all cases within five years of the filing date of the prior plan. As part of its IRP, the state's utilities are required to maximize the use of cost effective energy efficiency and other demand side resources.

Each plan is to include assessments of: (1) future demand for the utility's service area; (2) demand-side energy management programs, including conservation, efficiency and load management programs; (3) supply options including owned capacity, market procurements, renewable energy and distributed energy resources; (4) distribution and transmission requirements, including the benefits and costs of "smart grid" technologies; (5) plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers; (6) the plan's long- and short-term environmental, economic and energy price and supply impact on the state; and, (7) plan integration and consistency with the state's energy strategy. Subsequent to electric industry restructuring, the PUC has waived electric utilities' requirement to respond to several of these plan requirements.

In deciding whether or not to approve the utility's plan, the PUC is to consider "potential environmental, economic, and health-related impacts of each proposed option. The law indicates that "the commission's approval of a utility's plan shall not be deemed a pre-approval of any actions taken or proposed by the utility in implementing the plan." The following order of energy policy priorities is to guide the PUC's evaluation, provided that such options have equivalent financial costs, equivalent reliability and equivalent environmental, economic and health-related impacts: (1) energy efficiency and other demand-side management resources; (2) renewable energy sources; and, (3) all other energy sources. Legislation enacted in 2015 calls for electric utilities, as part of IRPs, to include in their assessment the implementation or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages.

In August 2016, the PUC adopted a settlement creating a statewide Energy Efficiency Resource Standard, or EERS, to become effective Jan. 1, 2018 for both electric and gas utilities to achieve all cost-effective energy efficiency. The EERS establishes long-term goals for achieving all cost-effective energy efficiency and a framework for achieving energy savings goals consisting of three-year planning periods. During the initial three-year period of the EERS for the calendar years 2018 through 2020, electric utilities are to achieve targeted savings as a percentage of 2014 statewide delivered sales, equivalent to 0.8% in 2018, 1.0% in 2019, and 1.3% in 2020, with cumulative overall savings of 3.1% compared to the 2014 baseline. Gas utilities are to achieve targeted savings as a percentage of 2014 statewide delivered sales equivalent to 0.7% in 2018, 0.75% in 2019, and 0.8% in 2020, with cumulative overall savings of 2.25% relative to the 2014 baseline. Utilities are to recover lost revenues resulting from the EERS through a lost revenue adjustment mechanism, or LRAM. Total recovery through the LRAM is capped at 110% of planned annual savings. The PUC indicated that approval of the LRAM does not limit consideration and approval at any time of a different lost revenue recovery mechanism, and that the utilities are required to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before. Utilities have the opportunity to earn a performance incentive at a target rate of 5.5% and a maximum level of 6.875% of spending.

Grid Modernization

In 2015, legislation was enacted calling for electric utilities, as part of their IRPs, to include in their assessments the implementation or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages. Subsequently in 2015, the PUC initiated an investigation into electric grid modernization, in accordance with the legislation. A consultant's report was issued on March 20, 2017.

Natural gas constraint issues

In 2015, the PUC initiated an investigation into potential approaches to ameliorate adverse wholesale electric market conditions in the state. That same year, the PUC staff issued a report concluding that the PUC had authority to approve electric distribution company, or EDC, natural gas supply contracts. In February 2016, Public Service Company of New Hampshire, or PSNH, filed for approval of a proposed 20-year contract between Eversource operating companies, including PSNH, and Algonquin Gas Transmission, LLC for natural gas capacity on Algonquin's Access Northeast Project, and recovery of associated costs through a new distribution rate tariff, to be assessed on all PSNH customers. In October 2016, the PUC issued a decision indicating that it did not have the statutory authority to approve the contract, despite the earlier staff finding. According to the PUC, the proposal was inconsistent with the state's restructuring law. The PUC stated "the competitive generation market is expected to produce a more efficient industry structure and regulatory framework, by shifting the risks of generation investments away from customers of regulated EDCs toward private investors in the competitive market." According to the PUC, "the long-term results should be lower prices and a more productive economy." According to the commission, "a more efficient structure involves placing investment risk on merchant generators who can manage that risk, and allowing customers to choose suppliers, thus enabling customers to pay market prices and avoid long-term over market costs." On Jan. 9, 2017, PSNH appealed the PUC's October 2016 ruling to the New Hampshire Supreme Court. The appeal is ongoing? (Section updated 12/8/17)

Renewable Energy

State law requires all electric providers, except municipal suppliers, to acquire renewable energy certificates equal to 25.2% of retail electricity sold to customers by 2025. The law identifies four classes of renewable resources. Class I includes new resources in operation after Jan. 1, 2006, that utilize: wind; geothermal; hydrogen derived from biomass fuels or methane gas; ocean thermal, wave, current, or tidal energy; methane gas; and, certain biomass technologies. In addition, Class I resources include: geothermal and solar thermal systems that were placed into service after Jan. 1, 2013; solar-electric energy not used to meet Class II; the incremental production of electricity in any year from an eligible biomass source, eligible methane source, or hydroelectric generating facility of any capacity, over its historical generation baseline; the production of electricity from Class III or IV sources that have been upgraded or re-powered; and, "useful thermal energy," defined as renewable energy delivered from Class I sources that can be metered and for which fuel or electricity would otherwise be consumed. Class II includes new solar technologies in operation after Jan. 1, 2006. Class III includes biomass with capacity of less than 25 MW and methane gas facilities in operation prior to Jan. 1, 2006. Class IV includes small hydroelectric facilities of under 5 MWs in operation prior to Jan. 1, 2006, and that comply with certain environmental protection criteria, and hydro-facilities up to 1 MW that comply with fish passages ordered by the Federal Energy Regulatory Commission.

The requirement that electric providers procure 25.2% of their power from renewable energy resources by 2025 and thereafter is being phased in as follows: 4% by 2008; 6% by 2009; 7.54% by 2010; 9.58% by 2011; 5.55% by 2012; 5.8% by 2013; 7.2% by 2014; 8.3% by 2015; 8.5% by 2016; 17.6% by 2017; 18.5% by 2018; 19.4% by 2019; 20.3% by 2020; 21.2% by 2021; 22.1% by 2022; 23% by 2023; 23.9% by 2024; and, 25.2% by 2025. Class I must account for 0.5% of total power requirements beginning in 2009, increasing to 15% by 2025.

Class II must account for 0.04% beginning in 2010, increasing to 0.5% in 2018, 0.6% in 2019 and 0.7% in 2020, and each year thereafter.

Class III must account for 3.5% of renewable resources in 2008, increasing to 8% in 2017 and each year thereafter. Class IV must comprise 0.5% of renewable resources in 2008, increasing to 1.5% in 2015 and each year thereafter.

The law specifies that in lieu of meeting the portfolio requirements for a given year, an electricity supplier may make an alternative compliance payment to a renewable energy fund.

Periodically, the PUC is to review the renewable portfolio standards and report its findings to the legislature. By statute, the PUC is permitted to adjust the Class III and Class IV requirements in certain circumstances, and the PUC lowered those requirements for calendar years 2013, 2014, 2015, and 2016.

Other renewable energy statutes: allow rate recovery of electric utilities' investments in distributed energy resources, up to 5 MW; provide for one-time incentive payments to owners of renewable generation facilities that are less than 5 MW; require electric utilities to offer a renewable energy service option for customers; and, require utilities to provide information regarding energy services and environmental characteristics of their electric service. Public Service Company of New Hampshire and Unitil Energy Systems have been relieved of their obligations to offer renewable energy service options.

In addition, legislation enacted on June 2, 2017, establishes a committee to study subsidies for energy projects provided by the renewable portfolio standard. The committee reported its findings and recommendations in November 2017. (Section updated 12/8/17)

Emissions Requirements

State statutes directed Public Service Company of New Hampshire, or PSNH, to reduce mercury emissions by 80% by July 1, 2013, through the installation of wet scrubber technology at its 430-MW coal-fired Merrimack Station. The law provided economic incentives, i.e., emission credits, either for earlier installation of the scrubber technology or for greater reductions in emissions. Installation of the wet scrubber became contentious, when, in 2008, PSNH announced that the cost of the project could exceed $450 million. The PUC opened a proceeding to establish whether it had the authority to determine, prior to the company beginning construction, whether the project is in the public interest. The PUC ultimately found that its "authority is limited to determining at a later time the prudence of the costs of complying with the requirements of [the law] and the manner of recovery for prudent costs." In 2009, the New Hampshire Supreme Court dismissed an appeal of the commission's findings. PSNH has completed construction of the scrubber, and a settlement was adopted by the PUC in July 2016 that, in addition to calling for the divestiture of PSNH's plants, resolved all issues related to the scrubber. Divestiture of PSNH's plants are underway. See the Electric regulatory reform/industry restructuring section for further details.

The state is part of the Regional Green House Gas Initiative, or RGGI, a multi-state effort to cap greenhouse gas emissions from power plants. However, a 2012 law permits New Hampshire to opt-out of participation from the RGGI program if two New England states exit, or if one New England state with 10% of total load withdraws from participation. In addition, the law calls for RGGI auction proceeds in excess of $1 per allowance to be refunded to default service customers. 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. For Maryland, the plan requires a 23% reduction. In February 2016, the U.S. Supreme Court stayed the rule, pending the outcome of a review by U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. The stay prevents 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.

On March 28, 2017, President Donald Trump issued an executive order that effectively initiated the process of reversing the steps that have been taken to date on the CPP. On April 28, 2017, the District Court granted a motion filed by the EPA to hold in abeyance for 60 days the cases involving challenges to the CPP. The D.C. Circuit also ordered parties to file briefs addressing whether the consolidated cases should be remanded to the EPA rather than held in abeyance.

In keeping with the Trump administration's promises to rescind one of the Obama administration's most prominent climate change initiatives, on Oct. 10, 2017, EPA Administrator Scott Pruitt began the formal process of reversing the efforts made to date to implement the Clean Power Plan, which was developed to reduce CO2 emissions from existing coal-fired power plants by 2030.

In a statement, Pruitt stated: "The Obama administration pushed the bounds of their authority so far with the CPP that the Supreme Court issued a historic stay of the rule, preventing its devastating effects to be imposed on the American people while the rule is being challenged in court. We are committed to righting the wrongs of the Obama administration by cleaning the regulatory slate. Any replacement rule will be done carefully, properly, and with humility, by listening to all those affected by the rule." (Section updated 12/8/17)

Reliability Issues

NA

Rate Structure

The PUC approved electric rate settlements in 2017 that move toward a more cost-based rate design with increases in fixed charges. On April 12, 2017, the PUC adopted a settlement for Liberty Utilities that establishes a residential monthly customer charge of $14.50, an increase of 23%, and calls for the company's two-block, inclining rate structure for electricity usage to be phased out in equal annual steps, with a flat rate becoming effective May 1, 2019.

In a rate case settlement adopted by the PUC on April 20, 2017, Unitil Energy Systems was permitted to increase its residential monthly fixed customer charge to $15.24 from $10.27. The overall revenue increase is to be allocated such that residential and outdoor lighting classes experience an overall rate increase that is 125% of the average overall distribution rate increase approved for each step rate change. The remainder of the deficiency is to be allocated on an equal percentage basis to the commercial and industrial classes. The existing inclining block kWh rate structure for residential customers is to be replaced by a flat, uniform per-kWh charge.

Net metering

On June 23, 2017, the PUC issued a decision removing the 100 MW cap on the total amount of generation capacity that may be owned or operated by customers eligible for net metering. The PUC also adopted an alternative net metering tariff for small customer-generators, i.e., those with renewable energy systems of 100 kW or less, which will remain in effect for a period of years while further data is collected and analyzed, time-of-use and other pilot programs are implemented, and a distributed energy resource valuation study is conducted. All existing net energy metered systems installed prior to Sept. 1, 2017, are to have their rate structure grandfathered through 2040 at current rates. New residential systems under 100KW approved after Sept. 1, 2017, are to be credited monthly at 100% of energy supply and transmission charges, but only 25% of distribution charges. Large-scale systems over 100kw will not have any changes in their net-metering rate. All systems are to receive cash credits instead of kWh credits. Net-metered customer-generators are to pay certain non-bypassable charges, such as the system benefits charge, stranded cost recovery charge, storm recovery surcharges, and the state electricity consumption tax based on the full amount of their electricity imports without any netting of exports. (Section updated 12/8/17)

General Information

Contact Information	430 North Salisbury Street Dobbs Building Raleigh, NC 27603-5918 (919) 733-4249
	http://www.ncuc.commerce.state.nc.us/
Number of Commissioners	7 of 7
Selection Method	Commissioners: Gubernatorial appointment, General Assembly confirmation Chairperson: Gubernatorial appointment
Term of Office	Commissioners: 6 years Chairperson: 4 years
Chairperson of Commission	Edward S. Finley
Deputy Chairperson of Commission	NA
Governor	Roy Cooper III (D)
Service Regulated	Bus companies, Electric utilities, Gas utilities, Household goods carriers, Sewer utilities, Telecommunications utilities, Water utilities
Commission Ranking	Average/1 (10/22/2013)
Commmission Budget	$7.70 million
Commissioner Salaries	Commissioners: $127,550 Chairperson: $141,950
Size of Commission Staff	50
Company Name, Abbreviated	North Carolina Utilities Commission's Rate Case History
Research Notes	RRA Articles
RRA Contact	Dan Lowrey

Commissioners

Person's Name	*Party Abbreviation*	*Date Role Began*	*Term Ends*
Edward S. Finley Chairman	D	01/2007	06/2019
ToNola Brown-Bland	D	06/2009	06/2023
James Patterson	R	07/2013	06/2019
Jerry Dockham	R	07/2013	06/2019
Lyons Gray	R	01/2016	06/2021
Daniel G. Clodfelter	D	07/2017	06/2023
Charlotte A. Mitchell	D	01/2018	06/2023

RRA Ranking History

Date of Ranking Change	*Commission Ranking*
10/22/2013	Average / 1
4/16/2012	Above Average / 3
7/7/1986	Above Average / 2
7/15/1982	Above Average / 3
7/2/1982	Above Average / 2

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

Commissioner Selection Process — Minority party representation is not required. Statutes specify that, beginning Jan. 1, 2012, the terms of new commissioners will be six years; previously, the terms had been eight years.

Commission Membership — Commissioner Finley's term as NCUC Chairman extends through June 30, 2019.

Staff Contacts — Sam Watson, General Counsel and Director of Legal and Administrative Division, (919) 715-7057

(Section updated 1/11/18)

RRA Evaluation

North Carolina regulation is overall relatively constructive from an investor viewpoint, as it has been for many years. In almost all of the major rate cases that were decided during the last several years, the NCUC adopted settlements, and in those cases that specified an ROE, the authorized return typically was slightly above the nationwide average for energy utilities at the time established. The NCUC permits timely recovery of electric fuel costs, purchased power expenditures, and the costs of certain materials used in reducing or treating emissions. In addition, the NCUC may pre-determine the prudence of a utility's decision to build a baseload generating plant and the facility's projected costs, thus reducing the uncertainty associated with future cost recovery. Despite controversy concerning events that followed a 2012 merger, the NCUC, in general, has not taken a restrictive stance towards business combinations. Most recently, in September 2016 in a proceeding involving the merger of the state's largest electric utility, the NCUC adopted a settlement and did not impose any onerous conditions. Gas utilities are permitted timely recovery of commodity and certain related costs, and the state's two major local distribution companies are authorized to employ revenue decoupling mechanisms. Also, the state's two largest gas utilities have been authorized to implement a rider that allows the companies to track and recover future capital expenditures they incur to comply with federal pipeline safety and integrity requirements outside of a general rate case. In May 2017, RRA completed a comprehensive audit of its regulatory rankings. The ranking accorded North Carolina did not change as a result of this process. RRA continues to accord North Carolina regulation an Average/1 ranking. (Section updated 5/12/17)

Commission Staff

Approximately 50 budgeted positions. The NCUC chairman has hiring authority for the NCUC professional staff. Most staff employees are protected by the State Personnel Act. The Public Staff, which is separate from the NCUC staff and represents consumer interests, has approximately 75 budgeted positions (see the Consumer Interest section). The Public Staff's fiscal 2015-2016 budget is approximately $8.8 million. Also, state statutes authorize the NCUC to engage private legal counsel to represent the State before federal courts and agencies in natural gas matters. (Section updated 2/2/17)

Consumer Interest

Represented largely by the Public Staff, which is headed by an executive director who is appointed by the governor for a six-year term, subject to confirmation by the General Assembly. Christopher J. Ayers is serving a six-year term as executive director of the

Public Staff that commenced on July 1, 2013. The Attorney General also intervenes in NCUC proceedings. Industrial and commercial customer interests are represented by, among others, the Carolina Utility Customers Association and Carolina Industrial Group for Fair Utility Rates. (Section updated 2/2/17)

Rate Case Timing/Interim Procedures

When seeking a rate change, a utility must notify the NCUC at least 30 days before filing, and must submit the rate petition 30 days prior to the requested effective date. The commission is then required to act on the rate petition within 270 days of the requested effective date, bringing the total elapsed time from filing to decision to approximately 10 months. In most instances, the NCUC has acted on permanent rate requests within seven months of the filing date.

Rate hearings are conducted by panels of three commissioners, or by the full commission, with the panel members and panel chair designated by the NCUC chairman. A unanimous panel decision constitutes an order of the Commission unless three commissioners not on the panel request NCUC review. Split panel decisions may be reviewed by the full commission upon the request of one of the parties to the rate proceeding.

If no NCUC action has occurred within six months following the proposed effective date, the utility may, after providing a 10-day notice to the commission, implement an increase, not to exceed 20% for any single rate classification, into effect, under bond and subject to refund. Because the NCUC has typically acted on permanent rate requests within six months of the proposed effective date, this ratemaking provision has been utilized only twice over the past several years. In 2012, Dominion Resources subsidiary Virginia Electric and Power, or VEPCO, implemented a temporary base rate increase during the pendency of a case that was initiated in March 2012 and ultimately decided in December 2012. In addition, on Nov. 1, 2016, VEPCO implemented a $34.7 million temporary base rate increase in a case that was initiated on March 31, 2016.

Interim rate increases may be requested for implementation before the completion of the above-noted six month time frame. However, before the NCUC can grant an interim increase, the utility is required to demonstrate that severe financial deterioration has occurred and that emergency conditions exist. No interim increases of this type have been requested in a number of years. (Section updated 2/2/17)

Rate Base and Test Period

State law requires the NCUC to utilize a year end, original cost rate base for an historic 12-month test period, and to consider changes that are known and quantifiable prior to the close of hearings. Legislation enacted in 2007 expanded the NCUC's ability to allow a cash return on construction work in progress, or CWIP, in a rate case for new baseload generating facilities by removing statutory language that had permitted utilities to earn a current cash return on CWIP only "to the extent...such inclusion is in the public interest and necessary to the financial stability of the utility in question."

The NCUC may pre-determine the appropriateness of a utility's decision to build a baseload generating facility. The utility may request, or the NCUC may require, an ongoing prudence review of the plant's construction costs. The utility is required to file annual progress reports on actual construction costs and any changes to cost estimates. In the context of a general rate case, the utility would be permitted to recover costs previously found to be prudent in rates following completion of the plant, except under strictly limited circumstances where such costs were subsequently determined to be imprudent based upon evidence that was not reasonably discoverable at the time the initial finding of prudence was made. If plant construction is not completed because of an unavoidable or unforeseen change in circumstances, the utility would be permitted to recover prudently incurred costs. (Section updated 2/2/17)

Return on Equity

ROE determinations typically have been slightly above the industry averages at the time established, and have, in the large majority of cases, been specified in NCUC approved settlements. On Dec. 22, 2016, the commission authorized Virginia Electric and Power a 9.9% ROE, following the adoption of a settlement. In 2013, the NCUC adopted a settlement in a base rate case for Duke Energy subsidiary Duke Energy Carolinas that incorporated a 10.2% equity return. Also in 2013, the NCUC adopted a settlement, thereby authorizing Duke Energy subsidiary Duke Energy Progress, formerly Carolina Power & Light, a 10.2% ROE.

On Oct. 28, 2016, gas distribution utility Public Service Company of North Carolina, or PSNC, a subsidiary of SCANA Corporation, was authorized a 9.7% ROE, following the NCUC's adoption of an amended stipulation. In a rate case decision issued in 2013, Piedmont Natural Gas was authorized a 10% equity return, following a settlement. (Section updated 2/2/17)

Accounting

In a number of cases, the NCUC has allowed utilities to defer post operational capital and operating costs incurred between the time a plant commenced operation and the date a rate decision recognizing the plant in rates was issued.

Utilities are permitted to collect estimated nuclear decommissioning costs from ratepayers. Duke Energy Progress owns all or part of four nuclear units: Robinson Nuclear Plant Unit No. 2, Brunswick Nuclear Unit No. 1 and No. 2, and Harris Plant Unit No. 1. Duke Energy Carolinas owns all or part of three nuclear stations comprised of seven units: McGuire 1 and 2; Catawba 1 and 2; and, Oconee 1, 2 and 3. Amounts collected are placed in external trusts.

The NCUC has authorized utilities, on a case-by-case basis, to defer expenses resulting from named tropical storms, hurricanes, and significant winter storms. (Section updated 2/2/17)

Alternative Regulation

The NCUC has authorized the state's major electric utilities to retain a percentage of the net savings associated with their demand-side management/energy efficiency programs.

In 2013, the NCUC, pursuant to state statute, authorized Piedmont Natural Gas to implement an integrity management rider, or IMR. The IMR allowed the company to track and recover, outside of a general rate case, future capital expenditures and associated costs incurred to comply with federal gas pipeline safety requirements. Expenditures eligible for recovery under the IMR are reported monthly. A filing to adjust rates under the IMR filings was to occur annually in November, to reflect costs incurred through the previous October, and the revised rates were to become effective the following February.

In November 2015, the NCUC approved a stipulation between the Public Staff and Piedmont Natural Gas that modified the IMR. The adopted stipulation excluded a percentage of various kinds of capital costs from recovery through the IMR, but allowed for biannual filings to revise rates. The IMR mechanism will be reviewed by the Commission at the earlier of four years from Dec. 1, 2015 or the date of the company's next general rate case filing, after which the IMR mechanism may be extended, modified, or terminated.

On Oct. 28, 2016, the NCUC adopted an amended stipulation authorizing Public Service Company of North Carolina to implement an IMR mechanism, similar to that in place for Piedmont Natural Gas, to recover capital expenses closed to plant in service after June 30, 2016, related to the company's transmission and distribution pipeline integrity management programs. The IMR mechanism is to be reviewed by the NCUC at the earlier of four years from the date it takes effect or the date of the company's next general rate case filing, after which the IMR mechanism may be extended, modified or terminated. (Section updated 2/2/17)

Court Actions

General rate case decisions are appealed directly to the North Carolina Supreme Court. Other NCUC decisions may be appealed first to the Court of Appeals and then to the Supreme Court. Judges are elected to these courts on a non-partisan basis. The courts have occasionally reversed portions of major rate case decisions.

In 2014, the Supreme Court reversed the NCUC's 2012 authorization of a 10.2% ROE in a fully litigated Virginia Electric and Power electric base rate case. The Court concluded that the NCUC had failed to make the necessary findings of fact to support its ROE determination. The Court remanded the case to the commission. However, the Court did not require the NCUC to receive additional evidence and did not preclude the Commission from adopting the 10.2% ROE on remand, if that return were properly supported. In July 2015, the NCUC reaffirmed the 10.2% ROE, finding that this equity return "is reasonable and fair for [the company] and its customers." (Section updated 2/2/17)

Legislation

The North Carolina General Assembly meets for a two year term beginning in odd-numbered years. In even numbered years it may consider only budgetary matters, bills that passed one chamber in the prior year, and the recommendations of a legislative commission. In odd numbered years, the General Assembly convenes in early-January and generally adjourns in July, while in even numbered years, it generally convenes in May and adjourns in July. The General Assembly consists of a Senate and House of Representatives. The Senate currently is comprised of 35 Republicans and 15 Democrats, while the House has 74 Republicans and 46 Democrats. No major utility-related legislation was enacted in 2015 or 2016.

The North Carolina House of Representatives passed on June 7, 2017 House Bill 589, legislation that, if enacted, would impact several areas of the state's energy policy, including renewable energy development. Among other things, the legislation would create a competitive procurement framework for new renewable energy resources by requiring electric utilities with more than

150,000 customers, i.e., Duke Energy Carolinas, or DEC, and Duke Energy Progress, or DEP, to issue a request for proposals. The request for proposals would be issued over a 45-month term for a total procurement of 2,660 MW of renewable energy resources. Contracts would be for a term of 20 years, but the term could be adjusted at the discretion of the NCUC. The utility would be able to participate as a developer of renewable energy resources but would be limited to a maximum of 30% of the procurement amount. H.B. 589 would establish a new renewable energy procurement program for large energy users, the military and the University of North Carolina, or UNC, system. Large energy users would be defined as those with a contract demand of 1 MW or greater, or 5 MWs or more at multiple service locations when combined in aggregate. The program would expire in five years or on Dec. 31, 2022, whichever is later. The program would have a cap of 600 MW of total capacity, with 100 MW set aside for the military and 250 MW set aside for UNC. (Section updated 6/19/17)

Corporate Governance

North Carolina statutes prohibit a utility, without NCUC authorization, from pledging its "faith, credit, or property" for the benefit of any holder of its securities, or for any other affiliated business interest, the result of which would negatively impact the utility's earnings, assets or liabilities. In addition, no utility may issue any securities, or assume any liability or obligation as lessor, lessee, guarantor, endorser, surety or otherwise unless authorized by the NCUC. The NCUC may allow an action only if it determines that such action is: (1) for some lawful corporate purpose of the utility; (2) is compatible with the public interest; and, (3) is necessary for proper service performance by the utility. The NCUC also has jurisdiction over utility mergers (see the Merger Activity section). (Section updated 2/2/17)

Merger Activity

In approving a merger or combination affecting a public utility, the NCUC must determine whether a proposed merger is justified by "the public convenience and necessity." The NCUC has interpreted the statute to require a determination that rates and service will not be adversely affected by the transaction. In addition, the NCUC has concluded that for the public convenience and necessity standard to be met, expected benefits must be at least equal to known and expected costs so that customers are not negatively impacted. Other factors to be considered by the NCUC include, but are not limited to, maintenance of, or improvement in, service quality, the extent to which costs can be lowered and rates can be maintained or reduced, and the continuation of effective state regulation.

Under the law, a public utility is defined "to include all persons affiliated through stock ownership with a public utility doing business in this State as parent corporation or subsidiary corporation to the extent the Commission finds that such affiliation has an effect on the rates or service of such public utility."

In 2006, the NCUC approved the merger of Duke Energy, or Duke, and Cinergy subject to conditions specified in a settlement, and the transaction closed later in 2006. As per the settlement and NCUC ruling, Duke Energy Carolinas, or DEC, was required to reduce retail electric rates by $117.5 million for one year following the consummation of the merger in order to flow related savings to ratepayers. In addition, any fuel-related savings associated with the merger flowed through the company's fuel clause. The company was required to contribute $12 million to several energy- and environmental-related programs.

In 2012, the NCUC approved the proposed merger of Duke and Progress Energy, or Progress, following settlements. In addition, the NCUC merger order required the companies to adopt a Commission-approved Code of Conduct. The initial settlement calls for Duke subsidiaries DEC and Duke Energy Progress, or DEP, to: (1) guarantee that the jurisdictional share of $650 million in savings (total North Carolina and South Carolina) flow to North Carolina retail customers over the first five years after the merger closes, i.e. in 2012 through 2016; (2) continue their current level of community financial support of approximately $16.5 million annually for a minimum of four years after the merger closes; (3) provide $15 million for low-income household weatherization, community college programs that target technical and vocational training, or similar organizations and initiatives; and, (4) be prohibited from recovering direct merger-related expenses.

A supplemental settlement specifies that, for five years following the merger's close, DEC/DEP are to refrain from seeking recovery of the costs of Federal Energy Regulatory Commission required transmission projects. After the initial five years, the companies may recover these costs, subject to a demonstration that the projects are needed to provide adequate and reliable retail service regardless of the merger. Also, the companies may not seek recovery of losses and costs, estimated at between $40 million and $50 million, associated with interim market power mitigation sales agreements that were approved by the FERC. In addition, during the interim mitigation period, which has been completed, DEC and DEP reduced retail rates by $43.6 million and $21.2 million, respectively, on a total-system basis to reflect the removal from retail rates of certain plant capacity that was not available to retail customers during the mitigation period. The rate reductions were achieved through a credit rider that was applied to the bills of DEC and DEP retail customers.

The merger closed in July 2012, and hours later, Duke's Board announced that William Johnson, who had been designated CEO under the merger agreement, was to step down and Jim Rogers again was to become Chairman, President, and CEO of Duke. Following an investigation, the NCUC adopted a settlement requiring the retirement of Mr. Rogers by the end of 2013. A special committee of Duke's Board of Directors oversaw the recommendation of a successor to Mr. Rogers. Other provisions of the settlement include: Duke was required to issue a statement acknowledging that its actions fell short of the NCUC's understanding of the company's obligations as a regulated utility in North Carolina; Duke is to maintain at least 1,000 employees in Raleigh, North Carolina, for at least five years from date of the settlement; Duke is to guarantee an additional $25 million in fuel and fuel related cost savings, over and above the amount the company is obligated to provide to North Carolina retail customers pursuant to the NCUC's Merger Order; and, Duke is to contribute an additional $5 million to workforce development and low income assistance in North Carolina, over and above the amount provided for in the Merger Order.

On Sept. 29, 2016, the NCUC adopted a settlement, thereby approving Duke Energy's acquisition of Piedmont Natural Gas. The salient conditions contained in the settlement and NCUC order include: (1) Piedmont's North Carolina rates would decrease by $10 million during the first two years after the acquisition to ensure Piedmont ratepayers benefit from cost savings generated by the acquisition; (2) the combined company would make annual charitable contributions totaling at least $17.5 million in North Carolina during each of the four years following the acquisition; (3) the combined company would commit $7.5 million for low income household energy assistance and community job training programs during the first year after the acquisition; (4) North Carolina retail customers are expected to receive $22.8 million in fuel related savings; (5) certain expenses related to the acquisition, including severance costs and investment banker and legal fees for transaction structuring, would not be recoverable from ratepayers; and, (6) Duke and Piedmont would be subject to a "Code of Conduct," specific to the acquisition, ensuring, among other things, that their ratepayers would continue to benefit from competitive natural gas prices. In addition, in their application for NCUC approval of the transaction, Duke and Piedmont indicated that they were not seeking to recover the acquisition premium and transaction costs from customers. The deal closed on Oct. 3, 2016. (Section updated 2/2/17)

Electric Regulatory Reform/Industry Restructuring

Restructuring has not occurred. (Section updated 2/2/17)

Gas Regulatory Reform/Industry Restructuring

Large customers have been permitted to purchase natural gas from alternative suppliers for a number of years. This option is not available for small commercial or residential customers. (Section updated 2/2/17)

Adjustment Clauses

Prudent electric fuel and fuel related costs are recoverable through a fuel adjustment clause, or FAC. Each utility has an annual hearing to review fuel costs, with a test period determined by the NCUC for each company. The proceedings provide for a true up of any over or under collections from the previous year, with interest included only for over collections. The costs of certain re-agents, e.g., limestone, used in reducing or treating emissions, as well as certain non-fuel purchased power costs for economic purchases, may be recovered through the FAC. The law limits the annual increase in recoverable costs related to certain purchased power contracts to 2% of a utility's total retail revenues.

The law provides that if a utility with nuclear generation fails to meet or exceed certain industry performance measures, there is a presumption of imprudence. Unless it can successfully rebut the presumption, the utility is required to forego recovery of a portion of the fuel costs incurred during the period under review. There is no reward provision.

State law authorizes the NCUC to approve an annual rider outside of a general rate case for electric utilities to recover reasonable and prudent costs incurred for the implementation of demand side management, or DSM, and energy efficiency, or EE, programs. Reasonable and prudent costs incurred by an electric utility for new DSM and EE measures implemented after Jan. 1, 2007, are recoverable through the annual rate rider. Recoverable costs include, but are not limited to, all capital costs, including cost of capital and depreciation expenses, administrative costs, implementation costs, incentive payments to program participants, and operating costs. The NCUC allows a utility to capitalize all or a portion of those costs that are intended to produce future benefits. Also, as permitted under the statues, the NCUC has approved incentives for adopting and implementing the DSM and EE measures (see the Alternative Regulation section). The NCUC limits the assignment of costs of new DSM and EE measures to customer classes that directly benefit from the programs. The costs of new DSM or EE measures may not be assigned to industrial or large commercial customers that notify the utility that they have implemented or will implement alternative DSM and EE measures and elect not to participate in the utility's new DSM and EE measures.

Costs to procure renewable energy are recoverable through the fuel clause and the renewable energy portfolio standard, or REPS, rider. The avoided cost is recoverable through the annual fuel clause, and payments in excess of the avoided cost are recoverable through the annual REPS rider. Incremental operation and maintenance costs and annual research and development, or R&D, expenses, with R&D costs not to exceed $1 million, are also recoverable through the REPS rider. Annual costs to be recovered through the REPS rider are limited to annual caps for residential, commercial and industrial customers. The cost of utility owned renewable generating facilities is recovered through a combination of the FAC, the annual REPS rider and base rates.

A purchased gas adjustment, or PGA, clause is utilized by natural gas utilities. Under NCUC rules: (1) gas purchasing practices are subject to an annual prudence review; (2) commodity and transportation rates are adjusted through the PGA; (3) a local distribution company may recover expenses for additional interstate pipeline capacity and storage added subsequent to a general rate case, subject to annual true-up; and, (4) changes in demand and storage costs are to be allocated to all customer classes based on fixed gas cost allocation factors established in the last general rate case.

In 2013, the NCUC authorized Piedmont Natural Gas to implement an integrity management rider, or IMR, that allows the company to track and recover future capital expenditures it incurs to comply with federal pipeline safety requirements outside of a general rate case. Pursuant to a stipulation adopted by the NCUC in November 2015, IMR filings to revise rates occur biannually. On Oct. 28, 2016, the NCUC adopted an amended stipulation authorizing Public Service Company of North Carolina to implement an IMR mechanism, similar to that in place for Piedmont, to recover capital expenses closed to plant in service after June 30, 2016, related to the company's transmission and distribution pipeline integrity management programs (see the Alternative Regulation section).

Piedmont Natural Gas utilizes a Margin Decoupling Mechanism/Tracker, formerly known as the Customer Utilization Tracker, that decouples the recovery of authorized margins from sales levels, thus mitigating the impact of weather and energy conservation programs on revenues. Public Service Company of North Carolina also has such a mechanism in place. (Section updated 2/2/17)

Integrated Resource Planning

NCUC rules require the utilities to file integrated resource plans, or IRPs, that cover a 15-year time horizon biennially in even numbered years, with updates submitted in odd numbered years. The IRPs are to consider conservation, demand-side management, or DSM, and other energy efficiency measures, or EE, as supply sources.

The NCUC may pre-determine the appropriateness of a utility's decision to build a baseload generating facility. The utility may request, or the NCUC may require, an ongoing review of the plant's construction costs (see the Rate Base and Test Period section).

State law authorizes the NCUC to approve an annual rider outside of a general rate case for electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of DSM and EE programs. In addition, the NCUC may award incentives to electric utilities for such programs, and has authorized the state's major electric companies to retain a percentage of the net savings associated with these programs. (Section updated 2/2/17)

Renewable Energy

State law requires that the retail sales of each of the state's investor-owned electric utilities be comprised of the following percentages of combined renewable energy and energy efficiency, or EE, savings by the indicated years: 3% of 2011 sales by 2012; 6% of 2014 sales by 2015; 10% of 2017 sales by 2018; and, 12.5% of 2020 sales by 2021 and thereafter. An EE measure is defined as an equipment, physical or program change that results in less energy being used to perform the same function; electric demand reduction programs can be used to meet the requirements. (Section updated 2/2/17)

Emissions Requirements

State law required reductions of approximately 75% in SO_2 emissions and approximately 60% in NO_x emissions from 2001 levels by the then 14 coal-fired plants owned by Duke Energy Carolinas and Duke Energy Progress by 2013, and the utilities achieved these reductions in the required timeframe.

In August 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. Many states, including North Carolina, have challenged the legality of the rule. The rule has been stayed by the U.S. Supreme Court, pending the outcome of a review by U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. The CPP litigation has been fully briefed before the D.C. Circuit and a ruling is expected in early 2017. The Supreme Court would be expected to take up the matter shortly thereafter. However, regardless of the judicial outcome, a Trump administration could take a number of actions that would rescind the CPP or significantly alter it. (Section updated 2/2/17)

Rate Structure

The NCUC has granted utilities the authority to implement special pricing plans, including economic development rates, self-generation deferral rates and customer specific contracts. In addition, the NCUC has encouraged implementation of time of day rates and various load management practices, and has moved toward more flattened rate structures and equalized rates of return for each class of electric service. Natural gas utilities are allowed to offer flexible sales and transportation rates to industrial customers. (Section updated 2/2/17)