December 2018

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Interest Rates, Money, and Financial Variables

	1999:1	1999:2	1999:3	1999:4	2000:1	2000:2	2000:3	2000:4	2001:1	2001:2	2001:3	2001:4	2002:1	2002:2	2002:3	2002:4	2003:1	2003:2	2003:3	2003:4	2004:1	2004:2	2004:3	2004:4	2005:1	2005:2	2005:3	2005:4
Percent per Annum, NSA																												
Federal Funds Rate	4.73	4.75	5.09	5.31	5.68	6.27	6.52	6.47	5.59	4.33	3.50	2.13	1.73	1.75	1.74	1.44	1.25	1.25	1.02	1.00	1.00	1.01	1.43	1.95	2.47	2.94	3.46	3.98
New York Fed Discount Rate	4.50	4.50	4.61	4.88	5.21	5.74	6.00	6.00	5.08	3.78	3.02	1.62	1.25	1.25	1.25	0.91	2.10	2.23	2.00	2.00	2.00	2.00	2.42	2.94	3.44	3.91	4.43	4.97
Prime Rate	7.75	7.75	8.10	8.37	8.69	9.25	9.50	9.50	8.62	7.34	6.57	5.16	4.75	4.75	4.75	4.45	4.25	4.24	4.00	4.00	4.00	4.00	4.42	4.94	5.44	5.91	6.43	6.97
US Treasury Yield Curve																												
3-Month Bill, Bond Equiv. Yield	4.52	4.57	4.77	5.18	5.68	5.88	6.19	6.19	4.94	3.75	3.24	1.94	1.75	1.75	1.67	1.36	1.18	1.06	0.95	0.93	0.93	1.09	1.51	2.04	2.59	2.92	3.44	3.92
6-Month Bill, Bond Equiv. Yield	4.58	4.76	4.96	5.42	5.94	6.23	6.29	6.19	4.82	3.76	3.22	1.97	1.90	1.90	1.67	1.39	1.19	1.07	1.02	1.02	1.00	1.36	1.79	2.29	2.87	3.18	3.70	4.25
1-Year Bill/Note Yield	4.66	4.88	5.16	5.61	6.19	6.22	6.13	5.90	4.60	3.78	3.30	2.24	2.32	2.34	1.81	1.53	1.30	1.15	1.22	1.30	1.22	1.78	2.08	2.47	3.06	3.34	3.79	4.29
2-Year Note Yield	4.85	5.28	5.63	5.94	6.53	6.56	6.22	5.71	4.59	4.19	3.64	2.87	3.20	3.22	2.23	1.89	1.65	1.42	1.68	1.86	1.69	2.45	2.56	2.81	3.44	3.64	3.95	4.36
5-Year Note Yield	4.88	5.44	5.77	6.06	6.59	6.42	6.06	5.55	4.80	4.83	4.48	4.09	4.46	4.44	3.35	3.01	2.91	2.57	3.14	3.25	2.99	3.72	3.51	3.49	3.88	3.87	4.04	4.39
10-Year Note Yield	4.98	5.54	5.88	6.14	6.48	6.18	5.89	5.57	5.05	5.27	4.98	4.77	5.08	5.10	4.26	4.01	3.92	3.62	4.23	4.29	4.02	4.60	4.30	4.17	4.30	4.16	4.21	4.49
30-Year Bond Yield	5.37	5.80	6.04	6.25	6.30	5.98	5.80	5.69	5.44	5.70	5.52	5.31	5.59	5.75	5.24	5.11	5.01	4.74	5.24	5.22	4.98	5.40	5.15	4.94	4.70	4.47	4.42	4.66
Short-Term Rates																												
3-Month Treasury Bill	4.41	4.45	4.65	5.04	5.52	5.71	6.02	6.02	4.82	3.66	3.17	1.91	1.72	1.72	1.64	1.33	1.16	1.04	0.93	0.92	0.92	1.08	1.49	2.01	2.54	2.86	3.36	3.83
6-Month Treasury Bill	4.41	4.58	4.78	5.21	5.69	5.96	6.02	5.93	4.65	3.64	3.12	1.93	1.85	1.86	1.63	1.36	1.17	1.05	1.00	1.00	0.98	1.33	1.75	2.23	2.79	3.09	3.58	4.11
3-Month Negotiable CDs	4.90	4.98	5.38	6.06	6.03	6.57	6.63	6.59	5.26	4.10	3.34	2.06	1.82	1.83	1.76	1.49	1.26	1.17	1.07	1.10	1.05	1.25	1.70	2.25	2.78	3.23	3.74	4.30
3-Month Commercial Paper	4.79	4.86	5.23	5.85	5.87	6.41	6.49	6.45	5.14	4.01	3.27	2.01	1.78	1.78	1.72	1.46	1.24	1.13	1.03	1.05	1.01	1.15	1.62	2.16	2.68	3.11	3.61	4.20
3-Month LIBOR	5.00	5.07	5.44	6.14	6.11	6.62	6.70	6.69	5.34	4.18	3.45	2.14	1.90	1.92	1.81	1.55	1.33	1.24	1.13	1.17	1.12	1.30	1.75	2.30	2.84	3.28	3.77	4.34
4-Year New Auto Loan (Banks)	8.34	8.31	8.44	8.67	8.88	9.22	9.62	9.64	9.17	8.67	8.30	7.86	7.80	7.74	7.58	7.34	7.11	7.05	6.76	6.82	6.72	6.43	6.55	6.71	6.86	6.92	7.08	7.43
Long-Term Rates																												
Bond Buyer Index, 20 GO Munis	5.05	5.21	5.55	5.91	5.97	5.85	5.56	5.44	5.14	5.26	5.08	5.10	5.18	5.15	4.90	4.89	4.82	4.49	4.92	4.76	4.52	4.98	4.71	4.50	4.45	4.33	4.30	4.51
Mortgage Rates																												
30-Year Conventional Fixed	6.88	7.21	7.80	7.83	8.26	8.32	8.03	7.64	7.01	7.13	6.97	6.78	6.97	6.82	6.29	6.08	5.84	5.51	6.01	5.92	5.60	6.13	5.89	5.73	5.76	5.72	5.76	6.22
11th District Cost of Funds	4.56	4.49	4.56	4.76	4.96	5.21	5.50	5.60	5.38	4.73	4.12	3.36	2.74	2.78	2.78	2.54	2.26	2.15	1.96	1.88	1.82	1.76	1.87	2.03	2.30	2.60	2.87	3.19
Billions of Dollars, SA																												
Monetary Aggregates and Reserves																												
M1	1097	1102	1098	1112	1113	1108	1101	1093	1102	1120	1165	1173	1192	1190	1194	1211	1235	1267	1294	1301	1319	1336	1352	1371	1370	1368	1374	1376
(Percent Change, Annual Rate)	1.9	1.7	-1.3	5.1	0.3	-1.8	-2.4	-2.8	3.4	6.8	16.8	2.9	6.4	-0.6	1.5	5.9	8.1	10.6	8.8	2.3	5.6	5.3	4.9	5.6	-0.2	-0.7	1.9	0.4
Cash & Travelers' Checks	476	488	499	516	528	528	532	537	545	554	570	584	599	613	625	631	643	653	658	668	673	681	695	704	708	713	721	728
Checkable Deposits	621	614	599	596	584	580	569	556	557	567	595	589	592	577	569	580	592	614	636	633	646	655	657	667	662	655	653	647
M2	4411	4475	4541	4603	4675	4754	4810	4881	5010	5136	5251	5370	5464	5507	5611	5727	5821	5937	6058	6052	6099	6229	6299	6383	6419	6464	6556	6644
(Percent Change, Annual Rate)	7.3	5.9	6.1	5.6	6.4	6.9	4.8	6.1	11.0	10.5	9.3	9.3	7.2	3.2	7.8	8.5	6.8	8.2	8.4	-0.4	3.1	8.8	4.6	5.4	2.3	2.8	5.8	5.5
M1 Velocity (GDP/M1)	8.58	8.64	8.82	8.90	8.99	9.25	9.37	9.55	9.50	9.46	9.10	9.09	9.05	9.16	9.21	9.14	9.06	8.93	8.94	9.05	9.04	9.06	9.10	9.13	9.31	9.44	9.56	9.69
M2 Velocity (GDP/M2)	2.14	2.13	2.13	2.15	2.14	2.16	2.15	2.14	2.09	2.06	2.02	1.99	1.97	1.98	1.96	1.93	1.92	1.91	1.91	1.94	1.95	1.94	1.95	1.96	1.99	2.00	2.00	2.01
Outstanding Credit																												
Com'l & Indus. Loans, Com'l.Banks	944	950	975	1001	1026	1063	1073	1085	1092	1072	1059	1022	1012	984	966	958	938	917	900	884	869	869	887	906	946	975	1001	1036
Percent Change, Annual Rate	2.3	2.3	11.1	11.0	10.5	15.0	3.9	4.7	2.5	-7.1	-4.7	-13.4	-3.8	-10.5	-7.0	-3.5	-8.2	-8.3	-7.4	-7.0	-6.3	-0.1	8.4	9.1	18.6	12.9	11.0	14.8
Nonmortgage Consumer Credit	1451	1479	1511	1531	1561	1610	1669	1717	1761	1792	1814	1868	1895	1927	1951	1972	2001	2033	2057	2077	2110	2128	2160	2192	2220	2248	2272	2291
Percent Change, Annual Rate	8.7	8.1	8.9	5.4	8.2	12.9	15.6	12.0	10.5	7.4	5.0	12.4	5.9	7.0	5.0	4.5	6.0	6.6	4.8	4.0	6.4	3.5	6.2	6.1	5.2	5.1	4.3	3.4
Mortgage Loans, All Issuers	5729	5868	6069	6210	6314	6476	6626	6767	6850	7057	7264	7450	7620	7847	8093	8359	8560	8851	9132	9366	9633	9980	10314	10649	10944	11341	11736	12117
Percent Change, Annual Rate	9.3	10.0	14.4	9.6	6.9	10.7	9.6	8.7	5.0	12.6	12.3	10.6	9.4	12.5	13.1	13.8	10.0	14.3	13.3	10.7	11.9	15.2	14.1	13.6	11.6	15.3	14.7	13.6
Mortgage Loans																												
Net Acquisitions	616	505	617	558	548	578	559	548	472	750	814	698	801	768	964	1102	838	1037	1119	990	1115	1309	1298	1347	1169	1562	1542	1601
Single-Family	462	388	466	394	395	432	450	423	503	620	618	471	695	619	807	903	701	854	899	814	862	1085	1014	1107	945	1228	1229	1224
Multi-Family	38	26	42	55	27	34	21	35	19	45	38	64	25	41	28	66	43	73	75	98	46	60	63	30	40	76	66	78
Commercial	111	87	105	105	128	115	90	92	-54	81	154	159	74	101	121	125	107	123	157	90	195	152	209	197	175	249	237	289
Farm	4	4	4	4	-2	-2	-2	-2	4	4	4	4	7	7	7	7	-12	-12	-12	-12	12	12	13	13	9	9	9	9
Outstandings, End of Period	5729	5868	6069	6210	6314	6476	6626	6767	6850	7057	7264	7450	7620	7847	8093	8359	8560	8851	9132	9366	9633	9980	10314	10649	10944	11341	11736	12117
Single-Family	4366	4474	4606	4701	4772	4897	5021	5125	5222	5394	5554	5678	5825	6013	6222	6434	6605	6848	7077	7261	7467	7759	8026	8293	8538	8850	9168	9450
Multi-Family	344	351	361	375	382	390	396	404	409	421	430	446	452	463	470	486	497	515	534	560	572	587	603	610	620	639	656	675
Commercial	935	957	1015	1046	1073	1103	1125	1152	1134	1156	1193	1237	1252	1279	1307	1343	1365	1398	1434	1462	1507	1545	1593	1650	1689	1753	1811	1887
Farm	84	85	86	87	87	86	85	85	86	87	88	89	90	92	94	95	92	89	86	83	86	89	93	96	98	100	102	105

2006:1	2006:2	2006:3	2006:4	2007:1	2007:2	2007:3	2007:4	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2009:4
4.46	4.91	5.25	5.25	5.26	5.25	5.07	4.50	3.18	2.09	1.94	0.51	0.18	0.18	0.16	0.12
5.43	5.90	6.25	6.25	6.25	6.25	5.93	5.02	3.67	2.33	2.25	1.31	0.50	0.50	0.50	0.50
7.43	7.90	8.25	8.25	8.25	8.25	8.18	7.52	6.21	5.08	5.00	4.06	3.25	3.25	3.25	3.25
4.50	4.83	5.04	5.03	5.12	4.86	4.41	3.47	2.08	1.66	1.52	0.30	0.22	0.18	0.16	0.06
4.65	5.03	5.17	5.11	5.13	4.99	4.58	3.68	2.14	1.88	1.86	0.74	0.40	0.32	0.25	0.16
4.63	5.02	5.09	4.99	5.01	4.93	4.52	3.62	2.10	2.07	2.12	0.99	0.57	0.52	0.45	0.35
4.60	4.99	4.93	4.74	4.77	4.81	4.38	3.48	2.02	2.42	2.36	1.21	0.91	1.01	1.03	0.87
4.55	4.99	4.84	4.60	4.65	4.76	4.50	3.79	2.75	3.16	3.11	2.18	1.76	2.23	2.47	2.30
4.57	5.07	4.90	4.63	4.68	4.85	4.73	4.26	3.66	3.89	3.86	3.25	2.74	3.31	3.52	3.46
4.62	5.14	4.99	4.74	4.80	4.99	4.94	4.61	4.41	4.58	4.45	3.68	3.45	4.17	4.32	4.33
4.39	4.70	4.91	4.90	4.98	4.74	4.30	3.39	2.04	1.63	1.49	0.30	0.21	0.17	0.16	0.06
4.48	4.84	4.97	4.92	4.93	4.80	4.42	3.57	2.09	1.83	1.82	0.73	0.39	0.32	0.25	0.16
4.72	5.18	5.39	5.32	5.31	5.32	5.42	5.02	3.23	2.76	3.06	2.82	1.08	0.62	0.30	0.22
4.60	5.06	5.26	5.18	5.18	5.21	5.13	4.43	2.77	2.07	2.13	1.50	0.39	0.26	0.24	0.17
4.76	5.21	5.43	5.37	5.36	5.36	5.45	5.03	3.26	2.75	2.91	2.72	1.24	0.85	0.41	0.27
7.39	7.60	7.95	7.92	7.74	7.92	7.82	7.59	7.27	6.84	6.92	7.06	6.92	6.79	6.61	6.55
4.40	4.59	4.43	4.19	4.20	4.39	4.58	4.43	4.61	4.66	4.74	5.43	4.99	4.71	4.52	4.29
6.24	6.60	6.56	6.25	6.22	6.37	6.55	6.23	5.88	6.09	6.32	5.87	5.06	5.03	5.16	4.92
3.53	3.91	4.28	4.37	4.36	4.27	4.34	4.16	3.60	2.95	2.72	3.01	2.03	1.60	1.39	1.73
1382	1381	1369	1369	1369	1375	1373	1375	1385	1396	1428	1530	1579	1629	1660	1685
1.7	-0.2	-3.5	0.2	-0.2	1.9	-0.7	0.6	2.8	3.3	9.6	31.8	13.4	13.1	8.0	6.0
740	747	749	754	757	761	766	768	764	769	783	812	842	855	863	868
642	634	620	616	612	614	607	607	620	627	645	718	737	774	797	817
6731	6803	6901	7016	7117	7237	7351	7429	7570	7698	7794	8047	8304	8402	8432	8477
5.3	4.3	5.9	6.9	5.8	6.9	6.4	4.3	7.8	7.0	5.0	13.6	13.4	4.8	1.4	2.2
9.85	9.96	10.13	10.25	10.38	10.46	10.59	10.68	10.58	10.61	10.39	9.51	9.11	8.81	8.69	8.68
2.02	2.02	2.01	2.00	2.00	1.99	1.98	1.98	1.94	1.92	1.90	1.81	1.73	1.71	1.71	1.73
1069	1119	1151	1183	1216	1264	1350	1418	1471	1498	1531	1559	1511	1436	1338	1265
13.2	20.1	12.1	11.4	11.7	16.8	30.2	21.6	15.8	7.7	9.0	7.5	-11.6	-18.4	-24.8	-20.0
2386	2396	2427	2457	2484	2519	2567	2609	2646	2662	2657	2644	2622	2590	2573	2555
17.6	1.7	5.3	5.0	4.6	5.7	7.8	6.8	5.7	2.6	-0.8	-2.0	-3.3	-4.7	-2.6	-2.8
12522	12922	13266	13529	13823	14119	14428	14632	14771	14808	14799	14731	14721	14673	14575	14481
14.1	13.4	11.1	8.2	9.0	8.8	9.1	5.8	3.9	1.0	-0.2	-1.8	-0.3	-1.3	-2.6	-2.6
1598	1620	1352	1077	1130	1266	1270	872	634	316	149	-148	156	80	-112	-162
1269	1335	1024	700	858	904	830	497	384	79	2	-278	159	83	-37	-18
35	36	40	61	76	52	101	129	57	54	28	27	7	40	14	-18
290	246	284	312	191	305	335	242	171	161	96	81	-22	-55	-100	-137
3	3	3	3	5	5	5	5	22	22	22	22	11	11	11	11
12522	12922	13266	13529	13823	14119	14428	14632	14771	14808	14799	14731	14721	14673	14575	14481
9779	10107	10367	10532	10761	10967	11163	11272	11348	11328	11291	11188	11178	11133	11054	10995
684	693	703	718	737	750	776	808	822	836	847	854	856	866	870	865
1954	2016	2088	2171	2215	2291	2377	2440	2483	2521	2532	2554	2549	2533	2508	2475
106	106	107	108	109	110	112	113	118	124	129	135	137	140	143	146

2010:1	2010:2	2010:3	2010:4	2011:1	2011:2	2011:3	2011:4	2012:1	2012:2	2012:3	2012:4	2013:1	2013:2	2013:3
0.13	0.19	0.19	0.19	0.16	0.09	0.08	0.07	0.10	0.15	0.14	0.16	0.14	0.12	0.08
0.61	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
0.11	0.15	0.16	0.14	0.13	0.05	0.02	0.01	0.07	0.09	0.10	0.09	0.09	0.05	0.03
0.19	0.22	0.20	0.19	0.17	0.10	0.06	0.05	0.11	0.15	0.15	0.14	0.11	0.09	0.06
0.37	0.38	0.27	0.26	0.27	0.21	0.13	0.11	0.16	0.19	0.18	0.17	0.15	0.13	0.12
0.92	0.87	0.54	0.48	0.69	0.57	0.28	0.26	0.29	0.29	0.26	0.27	0.27	0.27	0.37
2.42	2.25	1.55	1.49	2.12	1.86	1.15	0.95	0.90	0.79	0.67	0.69	0.83	0.92	1.51
3.72	3.49	2.79	2.86	3.46	3.21	2.43	2.05	2.04	1.82	1.64	1.71	1.95	2.00	2.71
4.62	4.37	3.86	4.16	4.56	4.34	3.70	3.04	3.14	2.94	2.75	2.86	3.14	3.15	3.72
0.11	0.15	0.16	0.14	0.13	0.05	0.02	0.01	0.07	0.09	0.10	0.09	0.09	0.05	0.03
0.18	0.22	0.19	0.18	0.17	0.10	0.06	0.05	0.11	0.15	0.14	0.14	0.11	0.09	0.06
0.21	0.42	0.34	0.28	0.28	0.22	0.29	0.42	0.33	0.30	0.27	0.23	0.22	0.20	0.21
0.16	0.28	0.25	0.23	0.23	0.17	0.15	0.14	0.16	0.20	0.21	0.20	0.16	0.11	0.09
0.26	0.44	0.39	0.29	0.31	0.26	0.30	0.48	0.51	0.47	0.42	0.32	0.29	0.28	0.26
6.45	6.26	6.24	5.87	5.85	5.79	5.89	5.40	5.07	4.88	4.88	4.82	4.69	4.13	4.46
4.35	4.35	4.07	4.39	5.17	4.70	4.18	4.04	3.75	3.89	3.75	3.51	3.76	3.97	4.72
5.00	4.91	4.45	4.41	4.85	4.66	4.31	4.01	3.92	3.80	3.55	3.36	3.50	3.69	4.44
1.75	1.80	1.71	1.58	1.47	1.35	1.31	1.21	1.20	1.12	1.07	1.03	0.98	0.96	0.96
1698	1713	1744	1815	1875	1931	2079	2157	2216	2260	2351	2435	2477	2526	2560
3.3	3.5	7.5	17.3	13.9	12.5	34.3	15.8	11.4	8.3	17.0	15.1	7.0	8.2	5.5
873	884	898	918	935	961	981	999	1023	1044	1064	1088	1104	1120	1142
825	828	846	897	940	971	1098	1158	1192	1216	1287	1348	1373	1406	1418
8478	8565	8650	8761	8871	9040	9452	9611	9774	9916	10122	10342	10493	10617	10779
0.0	4.2	4.0	5.2	5.1	7.8	19.5	6.9	6.9	6.0	8.6	9.0	6.0	4.8	6.2
8.67	8.71	8.65	8.40	8.15	8.02	7.50	7.32	7.23	7.15	6.91	6.72	6.69	6.59	6.58
1.74	1.74	1.74	1.74	1.72	1.71	1.65	1.64	1.64	1.63	1.61	1.58	1.58	1.57	1.56
1210	1190	1186	1192	1207	1234	1270	1304	1351	1398	1434	1474	1500	1522	1540
-16.3	-6.5	-1.4	2.2	5.0	9.1	12.2	11.2	15.3	14.6	10.8	11.6	7.2	6.0	4.8
2537	2520	2519	2647	2673	2695	2719	2757	2791	2836	2871	2918	2966	3002	3049
-2.8	-2.6	-0.1	21.8	4.0	3.3	3.7	5.7	5.0	6.6	5.1	6.7	6.7	5.0	6.5
14327	14211	14106	13896	13807	13707	13627	13573	13491	13416	13370	13339	13295	13295	13326
-4.2	-3.2	-2.9	-5.8	-2.5	-2.9	-2.3	-1.6	-2.4	-2.2	-1.4	-0.9	-1.3	0.0	0.9
-400	-230	-239	-204	-156	-207	-203	-108	-125	-116	-85	-15	7	118	144
-301	-44	-111	-97	-54	-88	-109	-92	-63	-73	-93	-100	-32	-30	65
-14	-17	18	11	-14	-12	4	26	6	20	40	42	27	31	42
-92	-178	-154	-125	-100	-119	-110	-55	-74	-70	-37	37	0	105	25
8	8	8	8	13	13	13	13	6	6	6	6	12	12	12
14327	14211	14106	13896	13807	13707	13627	13573	13491	13416	13370	13339	13295	13295	13326
10864	10796	10723	10524	10461	10393	10335	10283	10218	10155	10107	10052	10000	9966	9977
862	858	862	866	862	859	860	867	868	873	883	894	901	908	919
2454	2407	2368	2352	2327	2295	2267	2256	2236	2217	2207	2220	2218	2242	2248
148	150	152	154	157	161	164	167	169	170	172	173	176	179	182

2013:4	2014:1	2014:2	2014:3	2014:4	2015:1	2015:2	2015:3	2015:4	2016:1	2016:2	2016:3	2016:4	2017:1	2017:2
0.09	0.07	0.09	0.09	0.10	0.11	0.12	0.14	0.16	0.36	0.37	0.40	0.45	0.70	0.95
0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.79	1.00	1.00	1.00	1.05	1.29	1.54
3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.29	3.50	3.50	3.50	3.55	3.79	4.04
0.06	0.05	0.03	0.03	0.02	0.03	0.02	0.04	0.13	0.29	0.26	0.30	0.44	0.60	0.90
0.09	0.08	0.05	0.05	0.08	0.09	0.09	0.18	0.31	0.45	0.40	0.44	0.57	0.72	1.03
0.12	0.12	0.10	0.11	0.15	0.22	0.25	0.35	0.46	0.58	0.57	0.56	0.76	0.89	1.12
0.33	0.37	0.42	0.52	0.54	0.60	0.61	0.69	0.83	0.84	0.77	0.73	1.01	1.24	1.29
1.44	1.60	1.66	1.70	1.60	1.45	1.52	1.55	1.59	1.37	1.24	1.13	1.61	1.94	1.81
2.75	2.76	2.62	2.50	2.28	1.97	2.17	2.22	2.19	1.92	1.75	1.56	2.13	2.44	2.26
3.79	3.68	3.44	3.26	2.97	2.55	2.88	2.96	2.96	2.72	2.57	2.28	2.83	3.04	2.90
0.06	0.05	0.03	0.03	0.02	0.03	0.02	0.04	0.12	0.29	0.26	0.30	0.43	0.59	0.89
0.09	0.08	0.05	0.05	0.08	0.09	0.09	0.17	0.31	0.44	0.39	0.43	0.56	0.71	1.01
0.21	0.21	0.20	0.21	0.20	0.19	0.18	0.19	0.18	0.18	0.18	0.17	0.17	0.23	0.24
0.10	0.10	0.10	0.10	0.11	0.12	0.12	0.18	0.25	0.47	0.48	0.50	0.65	0.81	0.99
0.24	0.24	0.23	0.23	0.24	0.26	0.28	0.31	0.41	0.62	0.64	0.79	0.92	1.07	1.20
4.42	4.23	4.50	4.16	4.06	4.53	4.15	4.09	4.00	4.17	4.33	4.25	4.45	4.52	4.67
4.63	4.50	4.33	4.25	3.87	3.52	3.70	3.77	3.64	3.36	3.26	2.90	3.57	3.88	3.70
4.30	4.36	4.23	4.14	3.97	3.73	3.83	3.95	3.90	3.74	3.59	3.45	3.81	4.17	3.99
0.84	0.73	0.67	0.67	0.68	0.70	0.68	0.64	0.65	0.67	0.69	0.67	0.60	0.60	0.65
2637	2727	2801	2834	2898	2985	3003	3035	3064	3131	3232	3297	3342	3412	3483
12.6	14.4	11.3	4.8	9.3	12.6	2.5	4.3	3.8	9.1	13.5	8.3	5.7	8.5	8.7
1159	1179	1208	1226	1245	1276	1292	1312	1335	1355	1376	1397	1417	1440	1469
1478	1548	1593	1608	1652	1709	1711	1723	1729	1776	1855	1900	1926	1972	2014
10971	11134	11309	11460	11605	11816	11953	12101	12267	12528	12756	12967	13163	13330	13500
7.4	6.1	6.4	5.4	5.2	7.5	4.7	5.0	5.6	8.8	7.5	6.8	6.2	5.2	5.2
6.48	6.27	6.22	6.25	6.16	6.02	6.07	6.04	5.99	5.88	5.77	5.70	5.68	5.62	5.56
1.56	1.54	1.54	1.55	1.54	1.52	1.52	1.51	1.50	1.47	1.46	1.45	1.44	1.44	1.43
1574	1635	1677	1725	1773	1835	1882	1913	1957	2024	2057	2078	2095	2082	2094
9.2	16.3	10.9	11.8	11.7	14.8	10.5	6.8	9.6	14.3	6.7	4.3	3.3	-2.6	2.3
3093	3148	3206	3262	3315	3369	3433	3494	3414	3471	3526	3589	3644	3690	3731
5.9	7.3	7.6	7.2	6.6	6.8	7.7	7.3	-8.9	6.9	6.4	7.3	6.3	5.2	4.5
13347	13338	13371	13426	13500	13521	13627	13729	13878	13935	14061	14233	14361	14444	14594
0.6	-0.3	1.0	1.7	2.2	0.6	3.2	3.0	4.4	1.6	3.7	5.0	3.6	2.4	4.2
134	114	182	195	281	261	463	380	447	387	521	652	517	495	607
7	-1	27	21	90	46	206	159	186	161	274	311	257	334	355
54	41	46	57	83	90	91	76	123	93	108	129	125	80	84
62	62	98	105	97	113	155	133	126	117	122	194	119	71	158
12	11	12	12	12	12	12	12	12	17	17	17	17	10	10
13347	13338	13371	13426	13500	13521	13627	13729	13878	13935	14061	14233	14361	14444	14594
9962	9928	9923	9935	9948	9919	9962	10010	10081	10085	10151	10238	10299	10347	10434
932	943	954	968	993	1016	1038	1057	1095	1119	1146	1178	1209	1229	1250
2268	2280	2303	2329	2362	2387	2424	2456	2493	2518	2548	2595	2626	2639	2679
185	188	191	194	197	200	203	206	209	213	217	222	226	228	231

2017:3	2017:4	2018:1	2018:2	2018:3	2018:4	2019:1	2019:2	2019:3	2019:4	2020:1	2020:2	2020:3	2020:4	2021:1	2021:2
1.15	1.20	1.45	1.74	1.92	2.19	2.44	2.69	2.91	2.96	3.16	3.20	3.42	3.42	3.42	3.42
1.75	1.80	2.03	2.30	2.51	2.78	3.03	3.28	3.50	3.55	3.75	3.78	4.00	4.00	4.00	4.00
4.25	4.30	4.53	4.80	5.01	5.28	5.53	5.78	6.00	6.05	6.25	6.28	6.50	6.50	6.50	6.50
1.05	1.23	1.59	1.87	2.08	2.41	2.64	2.78	2.92	2.92	3.07	3.08	3.27	3.25	3.24	3.24
1.15	1.38	1.78	2.05	2.25	2.59	2.80	3.04	3.25	3.34	3.51	3.57	3.71	3.73	3.73	3.74
1.24	1.55	1.94	2.25	2.47	2.70	2.88	3.09	3.27	3.38	3.51	3.57	3.67	3.69	3.69	3.70
1.36	1.70	2.16	2.47	2.67	2.86	2.98	3.18	3.34	3.45	3.55	3.62	3.67	3.69	3.70	3.71
1.82	2.07	2.54	2.77	2.81	2.95	3.00	3.16	3.28	3.37	3.43	3.49	3.50	3.52	3.52	3.52
2.24	2.37	2.76	2.92	2.93	3.11	3.14	3.28	3.38	3.43	3.49	3.53	3.55	3.55	3.55	3.55
2.82	2.82	3.03	3.08	3.07	3.35	3.41	3.53	3.62	3.67	3.72	3.76	3.78	3.78	3.79	3.80
1.04	1.21	1.56	1.84	2.04	2.36	2.59	2.72	2.86	2.86	3.01	3.02	3.20	3.18	3.17	3.17
1.12	1.35	1.74	2.00	2.20	2.52	2.72	2.95	3.15	3.24	3.40	3.46	3.59	3.61	3.61	3.62
0.26	0.26	0.31	0.34	0.42	0.58	1.45	2.13	2.60	2.88	3.26	3.41	3.58	3.58	3.58	3.58
1.18	1.31	1.73	2.04	2.14	2.36	2.55	2.79	2.99	3.05	3.24	3.28	3.48	3.48	3.48	3.48
1.32	1.47	1.93	2.34	2.34	2.57	2.83	2.98	3.12	3.14	3.31	3.33	3.54	3.54	3.54	3.55
4.42	4.81	4.74	5.05	5.05	5.15	5.77	6.20	6.55	6.80	6.93	7.01	7.05	7.07	7.07	7.07
3.55	3.53	3.73	3.89	3.97	4.32	4.29	4.40	4.50	4.55	4.60	4.63	4.65	4.65	4.65	4.65
3.89	3.92	4.27	4.54	4.57	4.85	4.92	5.03	5.10	5.15	5.20	5.23	5.26	5.26	5.26	5.26
0.72	0.75	0.80	0.90	1.02	1.06	1.46	2.05	2.39	2.58	2.75	2.94	3.11	3.21	3.24	3.27
3553	3599	3642	3658	3698	3709	3733	3759	3783	3809	3829	3846	3862	3879	3900	3921
8.2	5.3	4.9	1.7	4.5	1.2	2.6	2.8	2.5	2.9	2.1	1.7	1.7	1.7	2.2	2.1
1496	1521	1544	1571	1602	1604	1622	1644	1665	1690	1709	1725	1742	1757	1776	1794
2057	2078	2098	2087	2097	2106	2111	2115	2117	2119	2120	2120	2121	2122	2124	2127
13663	13793	13883	14034	14200	14316	14424	14518	14616	14718	14803	14894	14977	15068	15175	15287
4.9	3.8	2.6	4.4	4.8	3.3	3.1	2.6	2.7	2.8	2.3	2.5	2.2	2.4	2.9	3.0
5.51	5.51	5.50	5.58	5.59	5.63	5.66	5.68	5.71	5.74	5.77	5.81	5.84	5.88	5.91	5.94
1.43	1.44	1.44	1.45	1.45	1.46	1.46	1.47	1.48	1.49	1.49	1.50	1.51	1.51	1.52	1.52
2111	2115	2142	2206	2220	2254	2286	2317	2348	2378	2408	2436	2464	2490	2515	2539
3.4	0.9	5.0	12.6	2.5	6.3	5.8	5.6	5.4	5.3	5.1	4.8	4.6	4.3	4.1	3.9
3768	3831	3862	3899	3950	3959	3971	3992	4021	4056	4086	4111	4130	4154	4186	4212
4.0	6.9	3.3	3.8	5.4	0.9	1.2	2.2	3.0	3.5	3.0	2.5	1.9	2.3	3.1	2.5
14730	14909	14998	15131	15239	15327	15403	15500	15604	15709	15812	15939	16072	16203	16328	16474
3.8	4.9	2.4	3.6	2.9	2.3	2.0	2.6	2.7	2.7	2.6	3.3	3.4	3.3	3.1	3.6
506	694	516	557	429	353	304	389	415	421	411	508	531	526	498	584
324	325	309	274	248	163	108	190	214	214	203	300	320	315	280	363
86	173	70	78	79	81	82	85	87	88	89	89	89	88	87	86
86	186	134	201	95	102	107	107	107	113	112	111	115	115	124	128
10	10	3	3	7	7	7	7	7	7	7	7	7	7	7	7
14730	14909	14998	15131	15239	15327	15403	15500	15604	15709	15812	15939	16072	16203	16328	16474
10526	10606	10648	10719	10781	10821	10848	10896	10949	11003	11053	11129	11209	11287	11357	11448
1272	1315	1333	1352	1372	1392	1413	1434	1456	1478	1500	1522	1545	1567	1589	1610
2698	2751	2780	2823	2847	2872	2899	2926	2952	2981	3009	3036	3065	3094	3125	3157
234	236	237	238	239	241	243	245	246	248	250	252	253	255	257	259

2021:3	2021:4	2022:1	2022:2	2022:3	2022:4	2023:1	2023:2	2023:3	2023:4	2024:1	2024:2	2024:3	2024:4
3.42	3.42	3.43	3.43	3.43	3.43	3.43	3.41	3.18	3.18	3.18	3.15	2.93	2.93
4.00	4.00	4.00	4.00	4.00	4.00	4.00	3.98	3.75	3.75	3.75	3.72	3.50	3.50
6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.48	6.25	6.25	6.25	6.22	6.00	6.00
3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.20	2.98	2.98	2.98	2.96	2.75	2.75
3.74	3.72	3.71	3.69	3.67	3.63	3.59	3.54	3.38	3.36	3.35	3.31	3.18	3.16
3.71	3.68	3.66	3.64	3.61	3.55	3.50	3.44	3.33	3.31	3.29	3.25	3.18	3.15
3.72	3.69	3.66	3.63	3.60	3.53	3.47	3.41	3.36	3.33	3.30	3.27	3.25	3.22
3.53	3.51	3.49	3.47	3.45	3.41	3.38	3.34	3.33	3.31	3.30	3.28	3.28	3.27
3.55	3.55	3.55	3.55	3.54	3.54	3.53	3.52	3.51	3.51	3.51	3.51	3.50	3.51
3.80	3.81	3.81	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.83	3.83
3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.13	2.92	2.92	2.92	2.89	2.69	2.69
3.62	3.61	3.59	3.58	3.56	3.52	3.48	3.43	3.28	3.26	3.25	3.22	3.09	3.07
3.58	3.58	3.59	3.59	3.59	3.59	3.59	3.51	3.34	3.34	3.33	3.26	3.08	3.08
3.48	3.48	3.49	3.49	3.49	3.50	3.50	3.47	3.25	3.25	3.26	3.23	3.02	3.02
3.55	3.55	3.56	3.56	3.56	3.56	3.56	3.54	3.33	3.33	3.33	3.30	3.10	3.10
7.08	7.06	7.04	7.03	7.01	6.97	6.95	6.91	6.90	6.88	6.88	6.86	6.86	6.85
4.65	4.64	4.64	4.64	4.63	4.63	4.62	4.62	4.61	4.61	4.61	4.61	4.60	4.61
5.26	5.26	5.25	5.25	5.24	5.24	5.23	5.22	5.20	5.19	5.19	5.19	5.17	5.17
3.32	3.34	3.34	3.34	3.34	3.33	3.31	3.29	3.23	3.19	3.16	3.13	3.09	3.05
3941	3961	3982	4003	4024	4044	4066	4086	4109	4128	4147	4165	4187	4208
2.1	2.1	2.2	2.1	2.1	2.0	2.1	2.0	2.2	1.9	1.8	1.7	2.1	2.1
1811	1829	1846	1863	1880	1896	1912	1928	1945	1961	1976	1991	2008	2023
2129	2133	2136	2140	2144	2148	2154	2158	2163	2167	2170	2173	2179	2185
15405	15531	15664	15801	15945	16082	16221	16364	16515	16670	16825	16984	17151	17322
3.1	3.3	3.5	3.6	3.7	3.5	3.5	3.6	3.7	3.8	3.8	3.8	4.0	4.1
5.97	6.00	6.03	6.06	6.09	6.12	6.14	6.17	6.19	6.22	6.25	6.28	6.31	6.34
1.53	1.53	1.53	1.53	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54
2562	2584	2605	2626	2646	2666	2686	2707	2727	2748	2769	2790	2811	2832
3.7	3.5	3.4	3.2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.0	3.0
4237	4263	4292	4316	4339	4362	4390	4412	4432	4454	4482	4505	4526	4546
2.4	2.5	2.8	2.2	2.2	2.1	2.6	2.0	1.8	2.0	2.6	2.0	1.9	1.8
16624	16772	16912	17077	17246	17405	17557	17736	17917	18085	18244	18428	18614	18790
3.7	3.6	3.4	4.0	4.0	3.7	3.5	4.1	4.1	3.8	3.6	4.1	4.1	3.8
600	593	561	659	676	637	608	716	723	673	634	737	743	705
376	360	324	419	428	386	350	452	454	399	355	453	455	412
86	85	84	83	83	82	81	81	80	80	80	80	80	81
132	141	146	150	157	162	170	177	181	187	192	197	202	205
7	7	7	7	7	7	7	7	7	7	7	7	7	7
16624	16772	16912	17077	17246	17405	17557	17736	17917	18085	18244	18428	18614	18790
11542	11632	11713	11818	11925	12021	12109	12222	12336	12435	12524	12637	12751	12854
1631	1653	1674	1694	1715	1736	1756	1776	1796	1816	1836	1856	1876	1896
3190	3225	3262	3299	3339	3379	3422	3466	3511	3558	3606	3655	3705	3757
260	262	264	266	267	269	271	273	274	276	278	280	281	283

2025:1	2025:2	2025:3	2025:4	2026:1	2026:2	2026:3	2026:4	2027:1	2027:2	2027:3	2027:4	2028:1	2028:2	2028:3	2028:4
2.93	2.93	2.93	2.93	2.93	2.89	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68
3.50	3.50	3.50	3.50	3.50	3.46	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
6.00	6.00	6.00	6.00	6.00	5.96	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75
2.75	2.75	2.75	2.74	2.74	2.71	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.51
3.14	3.12	3.10	3.08	3.06	3.02	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.90	2.90	2.90
3.12	3.10	3.07	3.04	3.01	2.98	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.91	2.91	2.91
3.19	3.16	3.12	3.09	3.06	3.02	2.99	3.00	2.99	2.99	2.99	2.99	3.00	3.00	3.00	3.00
3.25	3.23	3.21	3.19	3.16	3.14	3.14	3.14	3.14	3.14	3.13	3.13	3.13	3.13	3.13	3.13
3.51	3.50	3.49	3.48	3.47	3.46	3.45	3.45	3.45	3.44	3.44	3.44	3.44	3.43	3.43	3.43
3.83	3.83	3.82	3.82	3.81	3.80	3.80	3.79	3.79	3.79	3.78	3.78	3.78	3.78	3.78	3.77
2.69	2.69	2.69	2.69	2.69	2.65	2.46	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.46
3.05	3.03	3.01	2.99	2.97	2.94	2.81	2.81	2.81	2.81	2.81	2.81	2.81	2.82	2.81	2.82
3.08	3.08	3.08	3.08	3.08	3.00	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83
3.02	3.02	3.02	3.02	3.02	2.98	2.78	2.78	2.78	2.78	2.77	2.78	2.78	2.78	2.78	2.78
3.09	3.10	3.09	3.09	3.08	3.04	2.84	2.84	2.84	2.84	2.83	2.83	2.83	2.83	2.83	2.84
6.83	6.81	6.80	6.78	6.75	6.74	6.74	6.74	6.74	6.74	6.73	6.73	6.73	6.73	6.73	6.73
4.61	4.60	4.59	4.59	4.58	4.57	4.57	4.57	4.57	4.56	4.56	4.56	4.56	4.55	4.55	4.55
5.17	5.16	5.16	5.15	5.14	5.12	5.10	5.10	5.09	5.09	5.09	5.09	5.08	5.08	5.08	5.08
3.03	3.01	3.00	2.99	2.98	2.96	2.91	2.88	2.86	2.85	2.85	2.85	2.86	2.86	2.86	2.87
4231	4254	4276	4298	4319	4341	4364	4388	4414	4441	4468	4496	4526	4556	4586	4617
2.2	2.2	2.1	2.0	2.0	2.0	2.2	2.2	2.4	2.4	2.5	2.5	2.6	2.7	2.7	2.7
2038	2054	2070	2087	2104	2121	2140	2158	2177	2196	2215	2234	2254	2274	2295	2315
2192	2200	2206	2211	2216	2220	2224	2230	2237	2245	2253	2262	2272	2282	2292	2302
17499	17679	17863	18050	18238	18431	18629	18831	19036	19241	19449	19658	19872	20089	20306	20522
4.1	4.2	4.2	4.3	4.2	4.3	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3
6.36	6.39	6.42	6.46	6.49	6.52	6.55	6.59	6.62	6.65	6.67	6.70	6.73	6.76	6.79	6.81
1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53
2853	2874	2895	2916	2938	2959	2981	3003	3025	3047	3070	3092	3115	3137	3160	3183
3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.9	2.9	2.9	2.9	2.9
4573	4596	4621	4647	4679	4708	4738	4770	4809	4844	4880	4916	4958	4994	5031	5069
2.4	2.0	2.2	2.3	2.8	2.4	2.6	2.7	3.4	2.9	3.0	3.0	3.5	3.0	3.0	3.0
18957	19149	19341	19521	19687	19874	20061	20235	20398	20583	20770	20946	21113	21305	21500	21684
3.6	4.1	4.1	3.8	3.5	3.9	3.8	3.5	3.2	3.7	3.7	3.4	3.2	3.7	3.7	3.5
669	764	769	719	665	749	748	697	649	740	749	705	668	768	779	736
370	459	458	402	344	424	417	362	309	394	397	348	306	402	408	364
81	82	82	82	82	82	83	83	82	82	83	84	84	84	84	84
212	216	222	228	232	236	241	246	251	256	262	266	271	276	280	281
7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
18957	19149	19341	19521	19687	19874	20061	20235	20398	20583	20770	20946	21113	21305	21500	21684
12946	13061	13176	13276	13362	13468	13573	13663	13740	13839	13938	14025	14102	14202	14304	14395
1917	1937	1957	1978	1998	2019	2040	2060	2081	2101	2122	2143	2164	2185	2206	2227
3810	3864	3919	3976	4034	4093	4154	4215	4278	4342	4407	4474	4542	4611	4681	4751
285	287	288	290	292	294	295	297	299	301	302	304	306	308	309	311

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Interest Rates, Money, and Financial Variables

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Percent per Annum															
Federal Funds Rate	4.97	6.24	3.89	1.67	1.13	1.35	3.21	4.96	5.02	1.93	0.16	0.18	0.10	0.14	0.11
New York Fed Discount Rate	4.62	5.74	3.38	1.17	2.08	2.34	4.19	5.96	5.86	2.39	0.50	0.72	0.75	0.75	0.75
Prime Rate	7.99	9.23	6.92	4.68	4.12	4.34	6.19	7.96	8.05	5.09	3.25	3.25	3.25	3.25	3.25
US Treasury Yield Curve															
3-Month Bill, Bond Equiv. Yield	4.76	5.99	3.47	1.63	1.03	1.40	3.22	4.85	4.46	1.39	0.15	0.14	0.05	0.09	0.06
6-Month Bill, Bond Equiv. Yield	4.93	6.16	3.44	1.71	1.07	1.61	3.50	4.99	4.59	1.65	0.28	0.20	0.10	0.14	0.09
1-Year Bill/Note Yield	5.08	6.11	3.48	2.00	1.24	1.89	3.62	4.93	4.52	1.82	0.47	0.32	0.18	0.18	0.13
2-Year Note Yield	5.43	6.26	3.82	2.64	1.65	2.38	3.85	4.82	4.36	2.00	0.96	0.70	0.45	0.28	0.31
5-Year Note Yield	5.54	6.15	4.55	3.82	2.97	3.43	4.05	4.75	4.43	2.80	2.19	1.93	1.52	0.76	1.17
10-Year Note Yield	5.64	6.03	5.02	4.61	4.02	4.27	4.29	4.79	4.63	3.67	3.26	3.21	2.79	1.80	2.35
30-Year Bond Yield	5.87	5.94	5.49	5.42	5.05	5.12	4.56	4.87	4.84	4.28	4.07	4.25	3.91	2.92	3.45
Short-Term Rates															
3-Month Treasury Bill	4.64	5.82	3.39	1.60	1.01	1.37	3.15	4.73	4.35	1.37	0.15	0.14	0.05	0.09	0.06
6-Month Treasury Bill	4.75	5.90	3.33	1.68	1.05	1.58	3.39	4.80	4.43	1.62	0.28	0.19	0.10	0.13	0.09
3-Month Negotiable CDs	5.33	6.46	3.69	1.73	1.15	1.56	3.51	5.15	5.27	2.97	0.56	0.31	0.30	0.28	0.21
3-Month Commercial Paper	5.18	6.31	3.61	1.69	1.11	1.49	3.40	5.03	4.99	2.12	0.26	0.23	0.17	0.19	0.11
3-Month LIBOR	5.41	6.53	3.78	1.79	1.22	1.62	3.56	5.19	5.30	2.91	0.69	0.34	0.34	0.43	0.27
4-Year New Auto Loan (Banks)	8.44	9.34	8.50	7.62	6.94	6.60	7.07	7.72	7.77	7.02	6.72	6.21	5.73	4.91	4.43
Long-Term Rates															
Bond Buyer Index, 20 GO Munis	5.43	5.71	5.14	5.03	4.75	4.68	4.40	4.40	4.40	4.86	4.63	4.29	4.52	3.73	4.27
Mortgage Rates															
30-Year Conventional Fixed	7.43	8.06	6.97	6.54	5.82	5.84	5.87	6.41	6.34	6.04	5.04	4.69	4.46	3.66	3.98
11th District Cost of Funds	4.59	5.32	4.40	2.71	2.06	1.87	2.74	4.02	4.28	3.07	1.69	1.71	1.34	1.10	0.93
Billions of Dollars, SA															
Monetary Aggregates and Reserves															
M1	1112	1093	1173	1211	1301	1371	1376	1369	1375	1530	1685	1815	2157	2435	2637
(Percent Change, Annual Rate)	1.8	-1.7	7.3	3.2	7.4	5.4	0.4	-0.5	0.4	11.3	10.1	7.7	18.8	12.9	8.3
Cash & Travelers' Checks	516	537	584	631	668	704	728	754	768	812	868	918	999	1088	1159
Checkable Deposits	596	556	589	580	633	667	647	616	607	718	817	897	1158	1348	1478
M2	4603	4881	5370	5727	6052	6383	6644	7016	7429	8047	8477	8761	9611	10342	10971
(Percent Change, Annual Rate)	6.2	6.0	10.0	6.6	5.7	5.5	4.1	5.6	5.9	8.3	5.3	3.4	9.7	7.6	6.1
M1 Velocity (GDP/M1)	8.66	9.38	9.02	9.03	8.81	8.91	9.48	10.09	10.51	9.61	8.58	8.26	7.21	6.65	6.37
M2 Velocity (GDP/M2)	2.09	2.10	1.97	1.91	1.89	1.91	1.96	1.97	1.95	1.83	1.70	1.71	1.62	1.57	1.53
Outstanding Credit															
Com'l & Indus. Loans, Com'l.Banks	1001	1085	1022	958	884	906	1036	1183	1418	1559	1265	1192	1304	1474	1574
Percent Change, Annual Rate	6.6	8.4	-5.8	-6.3	-7.7	2.6	14.3	14.1	19.9	10.0	-18.8	-5.8	9.3	13.1	6.8
Nonmortgage Consumer Credit	1531	1717	1868	1972	2077	2192	2291	2457	2609	2644	2555	2647	2757	2918	3093
Percent Change, Annual Rate	7.7	12.1	8.8	5.6	5.3	5.5	4.5	7.2	6.2	1.3	-3.4	3.6	4.2	5.8	6.0
Mortgage Loans, All Issuers	6210	6767	7450	8359	9366	10649	12117	13529	14632	14731	14481	13896	13573	13339	13347
Percent Change, Annual Rate	10.8	9.0	10.1	12.2	12.1	13.7	13.8	11.7	8.1	0.7	-1.7	-4.0	-2.3	-1.7	0.1
Mortgage Loans															
Net Acquisitions	574	558	683	909	996	1267	1468	1411	1135	238	-10	-268	-168	-85	101
Single-Family	428	425	553	756	817	1017	1157	1082	772	47	47	-138	-86	-82	3
Multi-Family	40	29	42	40	72	50	65	43	90	42	11	-1	1	27	38
Commercial	102	106	85	105	119	188	237	283	268	127	-79	-137	-96	-36	48
Farm	4	-2	4	7	-12	12	9	3	5	22	11	8	13	6	12
Outstandings, End of Period	6210	6767	7450	8359	9366	10649	12117	13529	14632	14731	14481	13896	13573	13339	13347
Single-Family	4701	5125	5678	6434	7261	8293	9450	10532	11272	11188	10995	10524	10283	10052	9962
Multi-Family	375	404	446	486	560	610	675	718	808	854	865	866	867	894	932
Commercial	1046	1152	1237	1343	1462	1650	1887	2171	2440	2554	2475	2352	2256	2220	2268
Farm	87	85	89	95	83	96	105	108	113	135	146	154	167	173	185

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent per Annum															
Federal Funds Rate	0.09	0.13	0.40	1.00	1.82	2.75	3.30	3.42	3.43	3.30	3.05	2.93	2.80	2.68	2.68
New York Fed Discount Rate	0.75	0.76	1.01	1.60	2.40	3.34	3.88	4.00	4.00	3.87	3.62	3.50	3.37	3.25	3.25
Prime Rate	3.25	3.26	3.51	4.10	4.90	5.84	6.38	6.50	6.50	6.37	6.12	6.00	5.87	5.75	5.75
US Treasury Yield Curve															
3-Month Bill, Bond Equiv. Yield	0.03	0.05	0.32	0.95	1.99	2.82	3.17	3.23	3.23	3.10	2.86	2.75	2.61	2.50	2.50
6-Month Bill, Bond Equiv. Yield	0.07	0.17	0.46	1.07	2.17	3.11	3.63	3.73	3.68	3.47	3.25	3.11	2.97	2.89	2.90
1-Year Bill/Note Yield	0.12	0.32	0.61	1.20	2.34	3.16	3.61	3.70	3.61	3.40	3.22	3.08	2.95	2.90	2.91
2-Year Note Yield	0.46	0.69	0.84	1.40	2.54	3.24	3.63	3.70	3.61	3.39	3.26	3.14	3.02	2.99	3.00
5-Year Note Yield	1.64	1.53	1.34	1.91	2.77	3.20	3.49	3.52	3.46	3.34	3.28	3.22	3.15	3.13	3.13
10-Year Note Yield	2.54	2.14	1.84	2.33	2.93	3.31	3.53	3.55	3.54	3.52	3.51	3.50	3.46	3.44	3.43
30-Year Bond Yield	3.34	2.84	2.60	2.89	3.13	3.56	3.76	3.80	3.82	3.82	3.83	3.83	3.80	3.79	3.78
Short-Term Rates															
3-Month Treasury Bill	0.03	0.05	0.32	0.93	1.95	2.76	3.10	3.16	3.16	3.03	2.80	2.69	2.56	2.45	2.46
6-Month Treasury Bill	0.06	0.16	0.46	1.05	2.11	3.02	3.51	3.62	3.56	3.36	3.15	3.02	2.88	2.81	2.82
3-Month Negotiable CDs	0.21	0.19	0.18	0.25	0.42	2.27	3.46	3.58	3.59	3.44	3.19	3.08	2.93	2.83	2.83
3-Month Commercial Paper	0.10	0.17	0.52	1.07	2.07	2.84	3.37	3.48	3.49	3.37	3.13	3.02	2.89	2.78	2.78
3-Month LIBOR	0.23	0.32	0.74	1.26	2.29	3.02	3.43	3.55	3.56	3.44	3.21	3.09	2.95	2.83	2.83
4-Year New Auto Loan (Banks)	4.24	4.19	4.30	4.61	5.00	6.33	7.02	7.07	7.01	6.91	6.86	6.81	6.74	6.73	6.73
Long-Term Rates															
Bond Buyer Index, 20 GO Munis	4.24	3.66	3.27	3.67	3.98	4.43	4.63	4.65	4.63	4.61	4.61	4.60	4.57	4.56	4.55
Mortgage Rates															
30-Year Conventional Fixed	4.17	3.85	3.65	3.99	4.56	5.05	5.24	5.26	5.25	5.21	5.18	5.16	5.11	5.09	5.08
11th District Cost of Funds	0.69	0.67	0.66	0.68	0.95	2.12	3.00	3.29	3.34	3.25	3.11	3.01	2.93	2.85	2.86
Billions of Dollars, SA															
Monetary Aggregates and Reserves															
M1	2898	3064	3342	3599	3709	3809	3879	3961	4044	4128	4208	4298	4388	4496	4617
(Percent Change, Annual Rate)	9.9	5.7	9.1	7.7	3.1	2.7	1.8	2.1	2.1	2.1	1.9	2.1	2.1	2.5	2.7
Cash & Travelers' Checks	1245	1335	1417	1521	1604	1690	1757	1829	1896	1961	2023	2087	2158	2234	2315
Checkable Deposits	1652	1729	1926	2078	2106	2119	2122	2133	2148	2167	2185	2211	2230	2262	2302
M2	11605	12267	13163	13793	14316	14718	15068	15531	16082	16670	17322	18050	18831	19658	20522
(Percent Change, Annual Rate)	5.8	5.7	7.3	4.8	3.8	2.8	2.4	3.1	3.5	3.7	3.9	4.2	4.3	4.4	4.4
M1 Velocity (GDP/M1)	6.05	5.95	5.60	5.41	5.53	5.64	5.79	5.91	6.03	6.13	6.25	6.36	6.49	6.60	6.70
M2 Velocity (GDP/M2)	1.51	1.49	1.42	1.41	1.43	1.46	1.49	1.51	1.52	1.52	1.52	1.51	1.51	1.51	1.51
Outstanding Credit															
Com'l & Indus. Loans, Com'l.Banks	1773	1957	2095	2115	2254	2378	2490	2584	2666	2748	2832	2916	3003	3092	3183
Percent Change, Annual Rate	12.6	10.4	7.1	1.0	6.5	5.5	4.7	3.8	3.2	3.1	3.0	3.0	3.0	3.0	2.9
Nonmortgage Consumer Credit	3315	3414	3644	3831	3959	4056	4154	4263	4362	4454	4546	4647	4770	4916	5069
Percent Change, Annual Rate	7.2	3.0	6.7	5.1	3.4	2.4	2.4	2.6	2.3	2.1	2.1	2.2	2.6	3.1	3.1
Mortgage Loans, All Issuers	13500	13878	14361	14909	15327	15709	16203	16772	17405	18085	18790	19521	20235	20946	21684
Percent Change, Annual Rate	1.2	2.8	3.5	3.8	2.8	2.5	3.1	3.5	3.8	3.9	3.9	3.9	3.7	3.5	3.5
Mortgage Loans															
Net Acquisitions	193	387.7	519.4	575.6	463.8	382.3	494.2	568.8	633.2	680.0	704.9	730.3	714.8	710.8	737.9
Single-Family	34	149.3	250.7	334.5	248.5	181.4	284.7	344.7	389.4	413.7	418.8	422.2	386.8	362.0	370.0
Multi-Family	57	94.9	113.7	106.1	77.2	85.6	88.9	85.9	83.0	80.7	80.1	81.5	82.4	82.8	83.8
Commercial	90	131.5	137.8	125.0	133.2	108.4	113.5	131.3	153.8	178.6	199.0	219.6	238.7	258.9	277.1
Farm	12	12.0	17.2	10.1	4.9	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Outstandings, End of Period	13500	13877.7	14360.6	14908.9	15326.8	15709.1	16203.3	16772.1	17405.2	18085.2	18790.2	19520.5	20235.3	20946.1	21683.9
Single-Family	9948	10080.5	10299.4	10606.5	10821.3	11002.7	11287.4	11632.1	12021.4	12435.2	12854.0	13276.2	13662.9	14025.0	14394.9
Multi-Family	993	1095.3	1209.0	1315.1	1392.2	1477.8	1566.7	1652.6	1735.6	1816.2	1896.3	1977.9	2060.2	2143.0	2226.8
Commercial	2362	2493.0	2626.2	2751.2	2872.3	2980.6	3094.1	3225.4	3379.2	3557.8	3756.8	3976.4	4215.1	4474.0	4751.1
Farm	197	208.8	226.0	236.1	241.0	248.0	255.0	262.0	269.0	276.0	283.0	290.0	297.0	304.0	311.0

ALLIANT ENERGY NDQ-LNT

RECENT PRICE 47.95 | P/E RATIO 21.3 (Trailing: 21.8 Median: 16.0) | RELATIVE P/E RATIO 1.29 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Raised 6/7/19
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Lowered 5/24/19
BETA .60 (1.00 = Market)

High:	21.2	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	45.6	46.6	49.1
Low:	11.4	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8

Target Price Range 2022 | 2023 | 2024

2022-24 PROJECTIONS

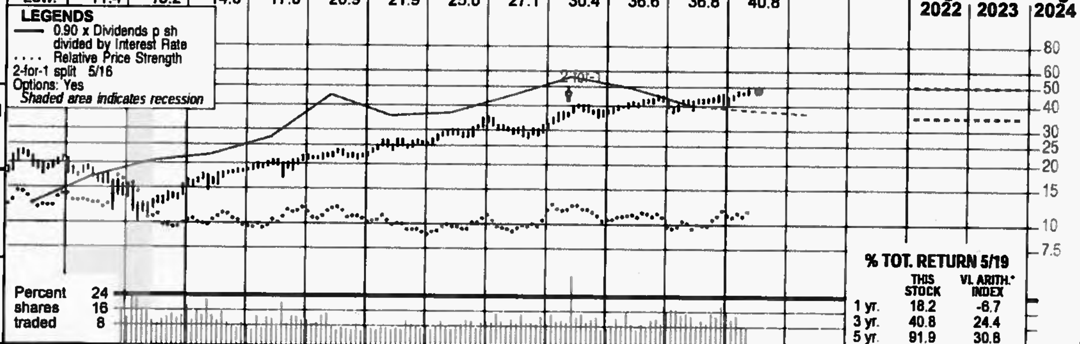
	Price	Gain	Ann'l Total Return
High	60	(+5%)	4%
Low	35	(-25%)	-3%

Insider Decisions

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

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	237	251	225
to Sell	201	209	240
Hld's(000)	169468	160932	182908



% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.2	-6.7
3 yr.	40.8	24.4
5 yr.	91.9	30.8

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.

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	*15.40*	*15.90*	Revenues per sh	*16.45*
2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.97	4.32	*4.40*	*4.60*	"Cash Flow" per sh	*5.20*
.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	*2.25*	*2.40*	Earnings per sh A	*2.80*
.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	*1.42*	*1.50*	Div'd Decl'd per sh B ■ †	*1.74*
5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.64	*6.75*	*6.50*	Cap'l Spending per sh	*6.15*
12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	*21.80*	*23.05*	Book Value per sh C	*27.55*
221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	*240.00*	*242.00*	Common Shs Outst'g D	*250.00*
13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	*15.0*
.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03			Relative P/E Ratio	*.85*
5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%			Avg Ann'l Div'd Yield	*4.1%*
3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	*3700*	*3850*	Revenues ($mill)	*4115*
208.6	303.9	304.4	337.8	362.1	385.5	380.7	373.8	455.9	512.1	*535*	*575*	Net Profit ($mill)	*695*
--	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	*11.0%*	*11.0%*	Income Tax Rate	*11.0%*
--	--	--	--	--	--	6.5%	7.0%	7.6%	7.8%	*7.5%*	*7.5%*	AFUDC % to Net Profit	*7.5%*
44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	49.0%	53.3%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	48.6%	46.7%	*48.0%*	*48.0%*	Common Equity Ratio	*48.0%*
5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	8192.8	9832.0	*10000*	*10500*	Total Capital ($mill)	*12000*
6203.0	6730.6	7037.1	7838.0	7147.3	8442.0	8970.2	9809.9	10798	12462	*13000*	*14000*	Net Plant ($mill)	*17000*
5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	6.8%	5.2%	*4.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	10.9%	11.2%	*10.0%*	*10.5%*	Return on Shr. Equity	*10.0%*
6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	10.9%	11.2%	*10.0%*	*10.5%*	Return on Com Equity E	*10.0%*
.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	4.0%	4.3%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
88%	64%	67%	64%	57%	59%	65%	72%	63%	61%	*63%*	*63%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 3/31/19
Total Debt $6133.4 mill. **Due in 5 Yrs** $1000.0 mill.
LT Debt $5362.2 mill. **LT Interest** $225.0 mill.
(LT interest earned: 3.3x)

Pension Assets-12/18 $808.6 mill. **Oblig.** $1175.0 mill.
Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 237,394,409 shs.

MARKET CAP: $11.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+2.0	-1.0	+2.0
Avg. Indust. Use (MWH)	11987	12102	12340
Avg. Indust. Revs. per KWH (¢)	7.04	7.16	7.25
Capacity at Peak (Mw)	5615	5375	5459
Peak Load, Summer (Mw)	5615	5375	5459
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.4	+.4
Fixed Charge Cov. (%)	295	319	322

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-.5%	-1.0%	*2.0%*
"Cash Flow"	3.0%	4.0%	*6.0%*
Earnings	4.5%	4.5%	*6.5%*
Dividends	7.5%	7.0%	*5.5%*
Book Value	4.0%	4.5%	*7.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	843.8	754.2	925.0	797.0	3320.0
2017	853.9	765.3	906.9	856.1	3382.2
2018	916.3	816.1	928.6	873.5	3534.5
2019	987.2	*840*	*1000*	*872.8*	*3700*
2020	*975*	*880*	*1050*	*945*	*3850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.43	.37	.57	.28	1.65
2017	.44	.41	.73	.41	1.99
2018	.52	.43	.87	.37	2.19
2019	.53	*.45*	*.89*	*.38*	*2.25*
2020	*.57*	*.48*	*.94*	*.41*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315	.315	.315	.315	1.26
2018	.335	.335	.335	.335	1.34
2019	.355	.355			

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, 41%; IA, 58%; MN, 1%. Elect. rev.: residential, 37%; commercial, 25%; industrial, 26%; wholesale, 5%; other, 7%. Fuel sources, 2018: coal, 37%; gas, 30%; other, 33%. Fuel costs: 45% of revs. 2018 depreciation rate: 5.9%. Estimated plant age: 16 years. Has approximately 3,885 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.

We look for modest earnings increases at Alliant Energy in 2019 and 2020. The company's largest utility subsidiary, Interstate Power and Light, is set to receive rate relief shortly from the Iowa Utilities Board. The utility is asking for an increase in electric and natural gas base rates of $204 million (11.8%) and $21 million (7.9%), respectively, to recoup investments in wind energy and enhancements made to its distribution network. Interim rates have already taken effect, and a final decision is expected by year's end. Meantime, Alliant struck an agreement last year to freeze electric rates at Wisconsin Power and Light, its other utility subsidiary. The company had previously requested increases of $61 million in 2019 and $133 million in 2020, but cost reductions and savings from the Tax Cuts and Jobs Act largely offset that requirement.

Interstate Power and Light received approval from the Iowa Utilities Board to implement a new energy efficiency plan for years 2019-2023. The plan is expected to result in 611 gigawatts of electric savings and 2.5 million therms of natural gas savings over the five-year period. The budget for the program is approximately $143 million, and savings are expected to eclipse $180 million.

The West Riverside Energy Center project is nearing completion. The 730-megawatt natural gas generating facility is over 80% complete and expected to go into service later this year. It will power more than 550,000 homes and businesses, and significantly expand Alliant's presence in southern Wisconsin.

Progress continues on the renewable-energy front. Recall that Alliant pledged to spend $1.8 billion between 2018 and 2020 on 1,000 megawatts of additional wind generation. Of the five projects expected to be built, two have been completed (English Farms and Upland Prairie), two are under construction, and one remains in the planning stages.

We think Alliant Energy's strengths are reflected in its stock price. The dividend yield is subpar for a utility, and total return potential to 2022-2024 is below the *Value Line* median. The equity's lofty valuation could also mean higher volatility than what is typical for a utility.

Daniel Henigson, CFA *June 14, 2019*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '09 (44¢); '10, (8¢); '11, (1¢); '12, (8¢) Next earnings rpt. due early August (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 '18: $89.7 mill., $0.38/sh. (D) In millions, adjusted for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '18: 10.0%, in WI in '18 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

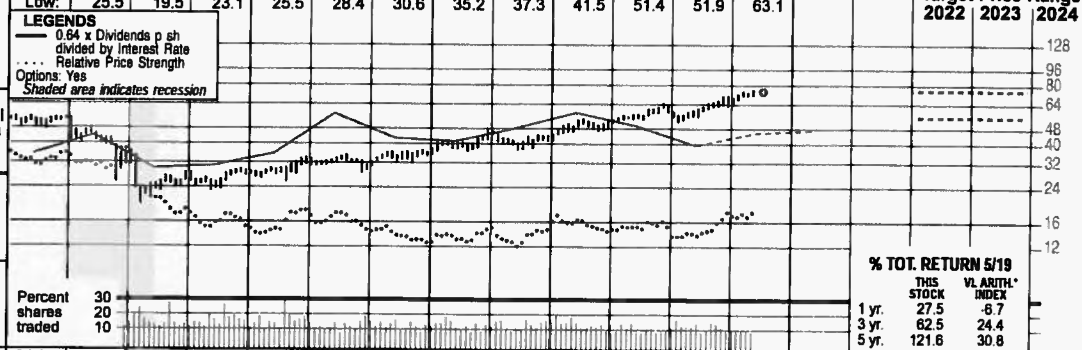
AMEREN NYSE-AEE

RECENT PRICE **74.45** | P/E RATIO **22.6** (Trailing: 21.4 Median: 16.0) | RELATIVE P/E RATIO **1.37** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS **3** Lowered 3/29/19
SAFETY **2** Raised 6/20/14
TECHNICAL **3** Raised 6/14/19
BETA .60 (1.00 = Market)

High:	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8	54.1	64.9	70.9	76.1	
Low:	25.5	19.5	23.1	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(Nil)	3%
Low	55	(-25%)	-3%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	25	12	0	0
to Sell	0	0	0	2	0	0	0	7	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	232	250	266
to Sell	228	257	245
Hld's(000)	176059	178307	176800

% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.5	6.7
3 yr.	62.5	24.4
5 yr.	121.6	30.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	*25.95*	*26.55*	Revenues per sh	*29.25*
6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	*7.95*	*8.40*	"Cash Flow" per sh	*10.25*
3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	*3.30*	*3.50*	Earnings per sh A	*4.25*
2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	*1.93*	*2.06*	Div'd Decl'd per sh B ■	*2.55*
4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	*9.85*	*13.15*	Cap'l Spending per sh	*10.50*
26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	*32.95*	*35.10*	Book Value per sh C	*40.75*
162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	*246.50*	*250.50*	Common Shs Outst'g D	*255.00*
13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	*Value Line*		Relative P/E Ratio	*.85*
6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.6%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 3/31/19
Total Debt $9356 mill. Due in 5 Yrs $2330 mill.
LT Debt $8221 mill. LT Interest $389 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $10 mill.
Pension Assets-12/18 $3899 mill.
Oblig $4459 mill.
Pfd Stock $142 mill. **Pfd Div'd** $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 245,597,156 shs. as of 4/30/19
MARKET CAP: $18 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	*6400*	*6650*	Revenues ($mill)	*7450*
624.0	669.0	602.0	589.0	518.0	593.0	585.0	659.0	683.0	821.0	*820*	*880*	Net Profit ($mill)	*1100*
34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	*19.0%*	*19.0%*	Income Tax Rate	*18.0%*
5.8%	7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	3.5%	4.4%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
49.7%	48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	*50.5%*	*50.0%*	Long-Term Debt Ratio	*49.5%*
49.1%	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	*48.5%*	*49.0%*	Common Equity Ratio	*50.0%*
15991	15185	14738	13384	12190	12975	13968	13840	14420	15632	*16675*	*17850*	Total Capital ($mill)	*20700*
17610	17853	18127	16096	16205	17424	18799	20113	21466	22810	*24100*	*26175*	Net Plant ($mill)	*29700*
5.3%	6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	5.9%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
7.8%	8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
7.8%	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
3.5%	3.6%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
56%	56%	63%	66%	76%	67%	70%	64%	64%	56%	*58%*	*59%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-4.2	-3.4	+5.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	351	362	329

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-3.5%	-1.5%	*2.5%*
"Cash Flow"	1.0%	4.5%	*6.5%*
Earnings	.5%	4.5%	*6.5%*
Dividends	-3.5%	2.5%	*6.0%*
Book Value	-.5%	.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1434	1427	1859	1356	6076.0
2017	1514	1538	1723	1402	6177.0
2018	1585	1563	1724	1419	6291.0
2019	1556	*1600*	*1794*	*1450*	*6400*
2020	*1600*	*1650*	*1900*	*1500*	*6650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.43	.61	1.52	.13	2.68
2017	.42	.79	1.18	.39	2.77
2018	.62	.97	1.45	.28	3.32
2019	.78	*.67*	*1.50*	*.35*	*3.30*
2020	*.75*	*.80*	*1.55*	*.40*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.41	.41	.41	.425	1.66
2016	.425	.425	.425	.44	1.72
2017	.44	.44	.44	.4575	1.78
2018	.4575	.4575	.4575	.475	1.85
2019	.475				

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Acq'd CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric rev. breakdown: residential, 43%; commercial, 32%; industrial, 8%; other, 17%. Generating sources: coal, 68%; nuclear, 24%; hydro & other, 3%; purchased, 5%. Fuel costs: 27% of revs. '18 reported deprec. rates: 3%-4%. Has 8,800 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

We estimate that Ameren's earnings will fall a bit short of the 2018 tally in 2019. That's because the June-quarter comparison will be difficult. Favorable weather conditions added $0.21 a share to the bottom line in the second period of 2018. Also, there is a refueling outage at the Callaway nuclear unit this spring, which will cost an estimated $0.09 a share. (There was no outage in 2018.) Ameren will benefit from forward-looking formula rate plans in Illinois for electricity and with the Federal Energy Regulatory Commission for transmission. The utility will also get a full year's benefit from a gas rate hike that took effect in Illinois last November. Our share-earnings estimate of $3.30 is within Ameren's targeted range of $3.15-$3.35 a share.

The utility has given notice that it will file a general rate case in Missouri as early as July. An order will be due 11 months after the filing date, so new tariffs will likely take effect at the start of June of 2020 if Ameren files its petition at the start of July. We think this will help earnings advance next year in line with the company's goal of 6%-8% growth annually. The upcoming rate case in Missouri will not include three wind projects that Ameren is adding (see below), so the utility will have to file another application there next year in order to place them in the rate base.

Ameren is adding wind capacity. The utility has reached agreements with wind developers that would see it spend $1.4 billion to add 857 megawatts of capacity by year-end 2020. (A 300-mw project still requires a certificate of need from the Missouri commission.) This will enable the company to meet the state's renewable-energy requirement. Some of this capital spending will be financed with common equity, in excess of the $100 million that is being raised annually through the dividend reinvestment plan.

Ameren stock is expensively priced. The dividend yield is low, by utility standards, and 3- to 5-year total return potential is minimal, despite the company's good dividend growth prospects over this time frame. In fact, the recent price is near the upper end of our 2022-2024 Target Price Range.

Paul E. Debbas, CFA *June 14, 2019*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); '17 (63¢); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '16-'17 EPS don't sum due to rounding. Next egs. report due early Aug. (B) Div'ds pd. late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '18: $6.29/sh (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '17: elec., none; in '11: gas, none; in IL in '14: elec., 8.7%, in '18: gas, 9.87%; earned on avg. com. eq., '18: 8.3%. Reg. Climate: MO, Avg.; IL, Below Avg.

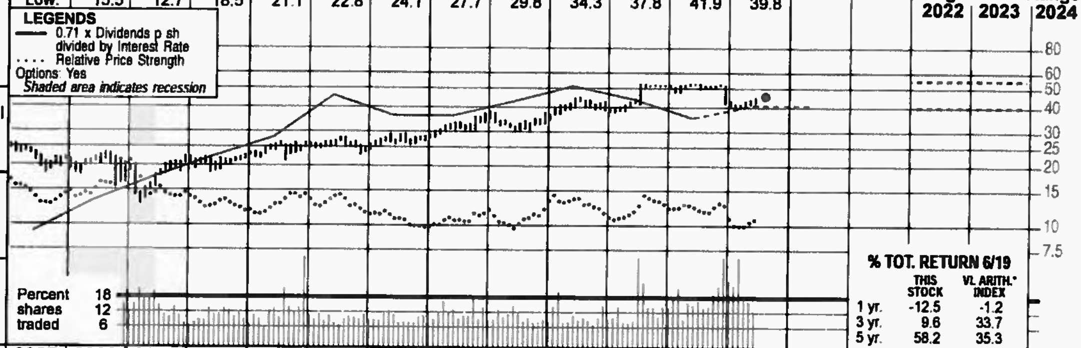
Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	80

AVISTA CORP. NYSE-AVA

RECENT PRICE 45.57 | P/E RATIO 16.0 (Trailing: 15.2; Median: 17.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 New 12/14/18
SAFETY 2 Raised 5/7/10
TECHNICAL 5 Lowered 7/26/19
BETA .60 (1.00 = Market)

High:	23.6	22.4	22.8	26.5	28.0	29.3	37.4	38.3	45.2	52.8	52.9	45.6		Target Price Range	
Low:	15.5	12.7	18.5	21.1	22.8	24.1	27.7	29.8	34.3	37.8	41.9	39.8		2022 2023 2024	



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+20%)	8%
Low	40	(-10%)	1%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	13	9	0	0
to Sell	1	0	0	0	0	2	3	0	4

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	108	117	151
to Sell	102	125	100
Hld's(000)	52832	49709	51692

% TOT. RETURN 6/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.5	-1.2
3 yr.	9.6	33.7
5 yr.	58.2	35.3

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	22.08	21.27	*21.25*	*22.05*	Revenues per sh	*24.00*
2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	5.01	*5.85*	*5.20*	"Cash Flow" per sh	*6.00*
1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	1.95	2.07	*2.85*	*2.15*	Earnings per sh A	*2.50*
.49	.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	1.43	1.49	*1.55*	*1.61*	Div'd Decl'd per sh B ■	*1.80*
2.21	2.47	3.23	3.14	4.04	4.09	3.88	3.64	4.20	4.61	5.05	5.47	6.46	6.34	6.30	6.46	*6.20*	*6.05*	Cap'l Spending per sh	*6.00*
15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	26.41	26.99	*28.50*	*29.25*	Book Value per sh C	*32.00*
48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	65.49	65.69	*67.00*	*68.00*	Common Shs Outst'g D	*71.00*
13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	23.4	24.5	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.79	1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	*Value Line*		Relative P/E Ratio	*1.05*
3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	3.1%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/19
Total Debt $1976.7 mill. **Due in 5 Yrs** $554.2 mill.
LT Debt $1752.8 mill. **LT Interest** $76.2 mill.
Incl. $51.5 mill. debt to affiliated trusts; $57.2 mill. capitalized leases.
(LT interest earned: 2.9x)
Pension Assets-12/18 $544.0 mill. **Oblig** $671.6 mill.
Pfd Stock None
Common Stock 65,750,156 shs. as of 4/29/19
MARKET CAP: $3.0 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1512.6	1558.7	1619.8	1547.0	1618.5	1472.6	1484.8	1442.5	1445.9	1396.9	*1425*	*1500*	Revenues ($mill)	*1700*
87.1	92.4	100.2	78.2	111.1	114.2	118.1	137.2	126.1	136.4	*190*	*145*	Net Profit ($mill)	*185*
34.3%	35.0%	35.4%	34.4%	36.0%	37.6%	36.3%	36.3%	36.5%	16.0%	*16.0%*	*16.0%*	Income Tax Rate	*16.0%*
4.2%	4.0%	5.2%	8.3%	8.8%	11.1%	10.1%	8.1%	7.9%	7.7%	*6.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
50.9%	51.6%	51.4%	50.8%	51.4%	51.0%	50.0%	51.2%	47.2%	50.5%	*50.0%*	*50.5%*	Long-Term Debt Ratio	*50.0%*
49.1%	48.4%	48.6%	49.2%	48.6%	49.0%	50.0%	48.8%	52.8%	49.5%	*50.0%*	*49.5%*	Common Equity Ratio	*50.0%*
2139.0	2325.3	2439.9	2561.2	2669.7	3027.3	3060.3	3379.0	3273.2	3580.3	*3830*	*4005*	Total Capital ($mill)	*4550*
2607.0	2714.2	2860.8	3023.7	3202.4	3620.0	3898.6	4147.5	4398.8	4648.9	*4865*	*5065*	Net Plant ($mill)	*5650*
5.5%	5.4%	5.5%	4.3%	5.4%	4.9%	5.1%	5.3%	5.0%	4.8%	*6.0%*	*4.5%*	Return on Total Cap'l	*5.0%*
8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	*10.0%*	*7.5%*	Return on Shr. Equity	*8.0%*
8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	*10.0%*	*7.5%*	Return on Com Equity E	*8.0%*
4.1%	3.3%	3.1%	.8%	2.9%	2.4%	2.3%	3.0%	1.9%	2.2%	*4.5%*	*2.0%*	Retained to Com Eq	*2.5%*
51%	60%	64%	88%	66%	69%	70%	64%	73%	72%	*54%*	*75%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-1.2	+4.7	-3.7
Avg. Indust. Use (MWH)	1314	1367	1344
Avg. Indust. Revs. per KWH (¢)	6.09	6.11	6.20
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+1.2	+1.4
Fixed Charge Cov. (%)	333	296	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-2.5%	-4.0%	*1.5%*
"Cash Flow"	3.0%	5.0%	*3.0%*
Earnings	5.5%	5.0%	*3.5%*
Dividends	8.5%	4.5%	*4.0%*
Book Value	4.0%	4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	418.2	318.8	303.4	402.1	1442.5
2017	436.5	314.5	297.1	397.8	1445.9
2018	409.4	319.3	296.0	372.2	1396.9
2019	396.5	*330*	*310*	*388.5*	*1425*
2020	*435*	*340*	*320*	*405*	*1500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.92	.43	.19	.62	2.15
2017	.96	.34	.07	.58	1.95
2018	.83	.39	.15	.70	2.07
2019	1.76	*.39*	*.10*	*.60*	*2.85*
2020	*.90*	*.45*	*.15*	*.65*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.33	.33	.33	.33	1.32
2016	.3425	.3425	.3425	.3425	1.37
2017	.3575	.3575	.3575	.3575	1.43
2018	.3725	.3725	.3725	.3725	1.49
2019	.3875	.3875			

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 402,000 electric, 350,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 38%; commercial, 32%; industrial, 11%; wholesale, 9%; other, 10%. Generating sources: hydro, 31%; gas & coal, 27%; purch., 42%. Fuel costs: 35% of revs. '18 reported depr. rate (Avista Utilities): 3.2%. Has 2,000 employees. Chairman & CEO: Scott L. Morris. Pres.: Dennis Vermillion, Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Avista has rate cases pending in three states. In Washington, the utility is seeking electric and gas hikes that would take effect on April 1, 2020 and April 1, 2021. Avista requested respective increases of $45.8 million (9.1%) and $18.9 million (3.5%) for electricity and $12.9 million (13.8%) and $6.5 million (6.1%) for gas. In Idaho, the company filed for an electric hike of $5.3 million (2.1%). New tariffs are expected to take effect at the start of 2020. In Oregon, Avista is seeking a $5.4 million (6.2%) boost. Each of these filings is based on a return of 9.9% on a common-equity ratio of 50%, except in Oregon, where a partial settlement calls for a 9.4% ROE.

The company needs rate relief in order to improve its return on equity. Avista expects its utility operations to earn an ROE of just 7.5% this year, two percentage points below the allowed ROE for most of its utility rate base. There are structural reasons that prevent Avista from earning its allowed ROE, but the gap shouldn't be as wide as it is. Filing frequent rate cases helps to address the problem of regulatory lag.

Earnings will be much higher than usual in 2019. In the first quarter, Avista received a breakup fee of $103 million after a proposed takeover of the company (for $53 a share in cash) failed to win regulatory approval. This added $1.01 a share to the bottom line. Our earnings estimate of $2.85 a share is within management's guidance of $2.78-$2.98.

Without the breakup fee in 2020, earnings will probably fall to a more-normal level. This is true even if Avista receives reasonable regulatory treatment in its rate cases. With a full year of rate relief in Washington in 2021, earnings should advance at a respectable pace.

Avista stock has underperformed its peers in 2019. The prices of many electric utility issues have risen over 15%, but Avista's share price has advanced only 7%. Perhaps this is due to the regulatory risk that the utility is facing, especially in Washington. The dividend yield and 3 to 5-year total return potential are each slightly above average for a utility. The possibility of a new takeover offer cannot be dismissed, but we advise against buying the stock on this basis.

Paul E. Debbas, CFA *July 26, 2019*

(A) Diluted EPS. Excl. nonrec. gain (losses): '03, (3¢); '14, 9¢; '17, (16¢); gains (loss) on discontinued ops.: '03, (10¢); '14, $1.17; '15, 8¢. '16 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. def'd chgs. In '18: $10.23/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '18: 9.5%; in ID in '17: 9.5%; in OR in '17: 9.4%; earned on avg. com. eq., '18: 7.8%. Regulatory Climate: WA, Below Avg.; ID, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	75

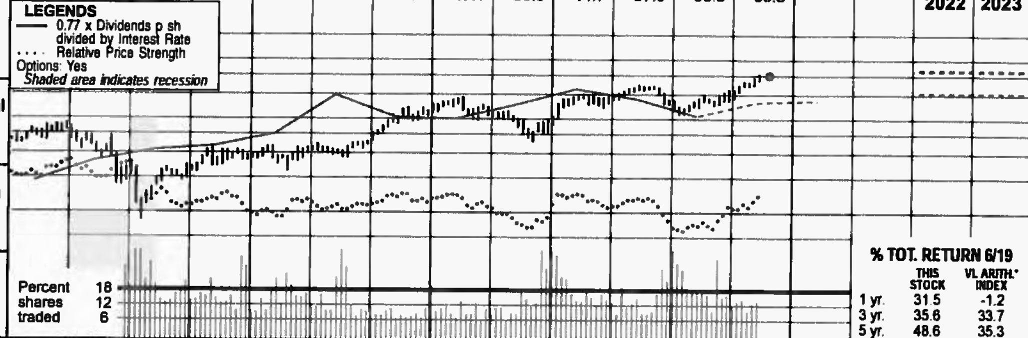
BLACK HILLS CORP. NYSE-BKH

RECENT PRICE **79.96** | P/E RATIO **22.5** (Trailing: 22.1, Median: 18.0) | RELATIVE P/E RATIO **1.32** | DIV'D YLD **2.6%** | VALUE LINE

TIMELINESS 1 Raised 3/29/19
SAFETY 2 Raised 5/1/15
TECHNICAL 3 Lowered 7/26/19
BETA .75 (1.00 = Market)

High:	44.0	28.0	34.5	34.8	37.0	55.1	62.1	53.4	64.6	72.0	68.2	82.0	
Low:	21.7	14.5	25.7	25.8	30.3	36.9	47.1	36.8	44.7	57.0	50.5	60.8	

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+5%)	4%
Low	65	(-20%)	-2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	4	4	7	3	6	8	3	3
to Sell	0	0	0	0	0	0	1	1	1

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	128	135	144
to Sell	113	112	128
Hld's(000)	52731	52878	52579

% TOT. RETURN 6/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.5	-1.2
3 yr.	35.6	33.7
5 yr.	48.6	35.3

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
35.17	34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	31.38	29.24	*29.25*	*29.60*	Revenues per sh	*32.00*
4.26	4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	7.15	6.61	*6.95*	*7.15*	"Cash Flow" per sh	*8.25*
1.84	1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	3.38	3.47	*3.55*	*3.65*	Earnings per sh A	*4.25*
1.20	1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	1.81	1.93	*2.05*	*2.17*	Div'd Decl'd per sh B ■	*2.60*
2.80	2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	6.09	7.62	*12.65*	*9.30*	Cap'l Spending per sh	*6.75*
21.72	22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	30.25	31.92	36.36	*38.60*	*40.55*	Book Value per sh C	*45.50*
32.30	32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	53.54	60.00	*61.50*	*62.50*	Common Shs Outst'g D	*62.50*
15.9	17.1	17.3	15.8	15.0	NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	22.3	19.5	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.91	.90	.92	.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98	.91	*Value Line*		Relative P/E Ratio	*.95*
4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	2.9%	2.7%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/19
Total Debt $3120.7 mill. **Due in 5 Yrs** $1209.5 mill.
LT Debt $2950.3 mill. **LT Interest** $112.0 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $1.1 mill.

Pension Assets-12/18 $390.8 mill. **Oblig** $445.4 mill.

Pfd Stock None

Common Stock 60,367,972 shs. as of 4/30/19

MARKET CAP: $4.8 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1269.6	1307.3	1272.2	1173.9	1275.9	1393.6	1304.6	1573.0	1680.3	1754.3	*1800*	*1850*	Revenues ($mill)	*2000*
89.7	64.6	40.4	86.9	115.8	128.6	128.3	140.3	186.5	192.5	*215*	*225*	Net Profit ($mill)	*270*
30.7%	26.4%	31.1%	35.5%	34.7%	33.7%	35.8%	25.1%	28.7%	19.2%	*14.0%*	*14.0%*	Income Tax Rate	*14.0%*
20.1%	28.0%	65.0%	5.4%	2.4%	2.4%	2.7%	5.3%	2.7%	1.4%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
48.4%	51.9%	51.4%	43.2%	51.6%	47.9%	56.0%	66.5%	64.5%	57.5%	*56.5%*	*55.0%*	Long-Term Debt Ratio	*52.5%*
51.6%	48.1%	48.6%	56.8%	48.4%	52.1%	44.0%	33.5%	35.5%	42.5%	*43.5%*	*45.0%*	Common Equity Ratio	*47.5%*
2100.7	2286.3	2489.7	2171.4	2704.7	2643.6	3332.7	4825.8	4818.4	5132.4	*5475*	*5630*	Total Capital ($mill)	*6000*
2160.7	2495.4	2789.6	2742.7	2990.3	3239.4	3259.1	4469.0	4541.4	4854.9	*5420*	*5785*	Net Plant ($mill)	*6500*
5.9%	4.4%	3.3%	5.5%	5.5%	6.1%	4.9%	4.0%	5.2%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
3.2%	.7%	NMF	1.8%	3.7%	4.3%	3.8%	3.3%	5.3%	3.9%	*4.0%*	*3.5%*	Retained to Com Eq	*3.5%*
62%	87%	NMF	75%	58%	54%	57%	62%	52%	55%	*58%*	*59%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+3.0	+.9	+2.7
Avg. Indust. Use (MWH)	17321	18376	19789
Avg. Indust. Revs. per KWH (¢)	7.80	7.69	7.41
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1086	1094	1104
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.8	+.8
Fixed Charge Cov. (%)	236	296	276

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	3.5%	1.5%	*1.0%*
"Cash Flow"	4.0%	5.0%	*3.5%*
Earnings	6.5%	11.0%	*5.0%*
Dividends	3.0%	4.0%	*6.5%*
Book Value	2.5%	3.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	450.0	325.4	333.8	463.8	1573.0
2017	547.5	341.9	335.6	455.3	1680.3
2018	575.4	355.7	322.0	501.2	1754.3
2019	597.8	*365*	*350*	*487.2*	*1800*
2020	*610*	*375*	*360*	*505*	*1850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.94	.31	.41	.97	2.63
2017	1.42	.41	.52	1.03	3.38
2018	1.59	.45	.32	1.11	3.47
2019	1.73	*.40*	*.42*	*1.00*	*3.55*
2020	*1.70*	*.42*	*.48*	*1.05*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.405	.405	.405	.405	1.62
2016	.42	.42	.42	.42	1.68
2017	.445	.445	.445	.475	1.81
2018	.475	.475	.475	.505	1.93
2019	.505	.505			

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 212,000 electric customers in CO, SD, WY and MT, and 1.1 million gas customers in NE, IA, KS, CO, WY, and AR. Has coal mining sub. Acq'd Cheyenne Light 1/05; utility ops. from Aquila 7/08; SourceGas 2/16. Discont. telecom in '05; oil marketing in '06; gas marketing in '11; gas & oil E&P in '17. Electric rev. breakdown: res'l, 33%; comm'l, 37%; ind'l, 19%; other, 11%. Generating sources: coal, 32%; other, 10%; purch., 58%. Fuel costs: 36% of revs. '18 deprec. rate: 3.4%. Has 2,900 employees. Chairman: David R. Emery. Pres. & CEO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills has some regulatory matters pending. In 2016, the company acquired SourceGas, with utilities in four states. This gave Black Hills two gas companies in Colorado, Wyoming, and Nebraska. The company has received regulatory approval to combine its gas utilities into one entity in Colorado and Wyoming, and is seeking the same approval in Nebraska. Black Hills requested rate increases of $2.5 million in Colorado, based on a 10.3% return on a 50.1% common-equity ratio, and $16.1 million in Wyoming. Orders are expected in late 2019 in Colorado and early 2020 in Wyoming. Black Hills plans to file a rate application in Nebraska in early 2020.

We have raised our 2019 and 2020 share-earnings estimates. First-quarter profits were above our expectation. With the earnings release, management raised its 2019 earnings guidance by a nickel a share, to $3.40-$3.60. We raised our estimate by a dime, to $3.55, and boosted our 2020 estimate by $0.05 a share, to $3.65, placing this at the midpoint of Black Hills' targeted range of $3.50-$3.80. Besides whatever the utilities receive from the pending rate cases, Black Hills gets some revenues annually from formula rate plans.

Capital spending plans are higher than in recent years. This is due in part to three notable projects that are scheduled for completion in 2019. These are the rebuilding of a 175-mile transmission line in South Dakota ($70 million), a nonutility 60-megawatt wind farm ($71 million), and a gas pipeline in Wyoming ($54 million). The increased capital spending is prompting Black Hills to issue $80 million-$100 million of common equity in 2019 and $40 million-$80 million of equity in 2020. This is significantly higher than the company's previous plan.

Black Hills stock is timely, but has a low dividend yield, by utility standards. With the recent quotation well within our 2022-2024 Target Price Range, total return potential is low. The stock price has risen 27% this year. Perhaps some takeover speculation is reflected in the quotation, but we advise against purchasing the equity in the hope that a buyout offer will occur.

Paul E. Debbas, CFA *July 26, 2019*

(A) Diluted EPS. Excl. nonrec. gains (losses): '08, ($1.55); '09, (28¢); '10, 10¢; '12, 4¢; '15, ($3.54); '16, ($1.26); '17, 14¢; '18, $1.31; gains (losses) on disc. ops.: '06, 21¢; '07, (4¢); '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢); '17, (31¢), '18, (12¢). Next earnings report due early Aug. (B) Div'ds paid early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '18: $25.82/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none specified; in CO in '17: 9.37%; earned on avg. com. eq., '18: 10.1%. Regul. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	70
Earnings Predictability	55

CENTERPOINT EN'RGY NYSE-CNP

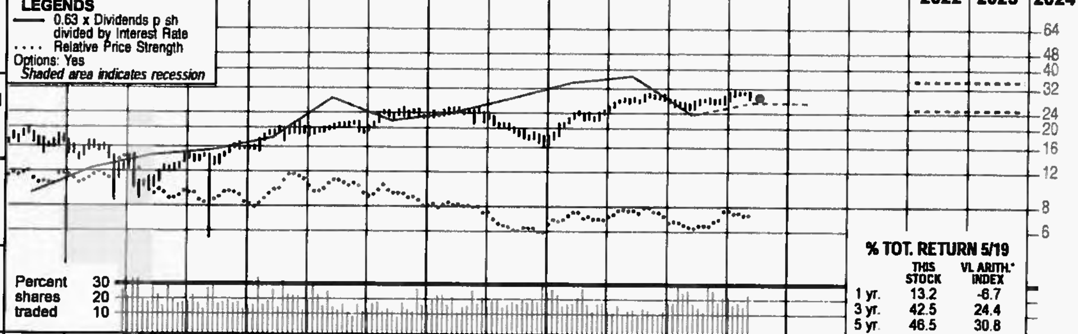
RECENT PRICE 28.82 | P/E RATIO 19.2 (Trailing: 45.0 Median: 17.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 6/22/18
SAFETY 3 Lowered 12/18/15
TECHNICAL 2 Raised 6/7/19
BETA .80 (1.00 = Market)

High:	17.3	14.9	17.0	21.5	21.8	25.7	25.8	23.7	25.0	30.5	29.6	31.4
Low:	8.5	8.7	5.5	15.1	18.1	19.3	21.1	16.0	16.4	24.5	24.8	27.7

Target Price Range 2022 | 2023 | 2024

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



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	9%
Low	25	(-15%)	1%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	9	9	2
to Sell	2	0	1	1	1	1	1	3	1

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	327	307	318
to Sell	232	292	277
Hld's(000)	402555	403708	393600

Percent shares traded 30 20 10

% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.2	-6.7
3 yr.	42.5	24.4
5 yr.	46.5	30.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
31.87	27.63	31.33	29.71	29.82	32.71	21.14	20.69	19.83	17.43	18.90	21.51	17.18	17.48	22.30	21.13	26.35	28.15	Revenues per sh	29.75
3.98	2.56	2.72	3.47	3.39	3.42	2.94	3.14	3.43	3.89	3.54	3.85	3.40	3.68	4.03	3.24	4.70	5.20	"Cash Flow" per sh	5.75
1.37	.61	.67	1.33	1.17	1.30	1.01	1.07	1.27	1.35	1.24	1.42	1.08	1.00	1.57	.74	1.50	1.85	Earnings per sh A	2.25
.40	.40	.40	.60	.68	.73	.76	.78	.79	.81	.83	.95	.99	1.03	1.35	1.12	1.16	1.20	Div'd Decl'd per sh B ■	1.35
2.11	1.72	2.23	3.21	3.45	2.95	2.96	3.55	3.06	2.84	3.00	3.20	3.68	3.28	3.31	3.29	4.85	4.95	Cap'l Spending per sh	5.00
5.75	3.59	4.18	4.96	5.61	5.89	6.74	7.53	9.91	10.06	10.09	10.60	8.05	8.03	10.88	12.53	18.50	19.15	Book Value per sh C	22.25
306.30	308.05	310.33	313.65	322.72	346.09	391.75	424.70	426.03	427.44	429.00	429.00	430.00	430.68	431.04	501.20	503.00	504.00	Common Shs Outst'g D	540.00
6.0	17.8	19.1	10.3	15.0	11.3	11.8	13.8	14.6	14.8	18.7	17.0	18.1	21.9	17.9	NMF	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	13.5
.34	.94	1.02	.56	.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.90	NMF			Relative P/E Ratio	.75
4.8%	3.7%	3.1%	4.4%	3.9%	5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	3.9%	5.1%	4.7%	4.8%	4.1%			Avg Ann'l Div'd Yield	4.5%
						8281.0	8785.0	8450.0	7452.0	8106.0	9226.0	7386.0	7528.0	9614.0	10589	13250	14200	Revenues ($mill)	16000
						372.0	442.0	546.0	581.0	536.0	611.0	465.0	432.0	679.0	368.0	870	1055	Net Profit ($mill)	1265
						32.1%	37.3%	33.6%	33.4%	31.4%	31.0%	35.1%	37.0%	36.1%	28.4%	22.0%	22.0%	Income Tax Rate	22.0%
						1.3%	2.7%	1.6%	2.6%	3.5%	4.1%	4.7%	3.5%	2.9%	5.4%	3.0%	3.0%	AFUDC % to Net Profit	2.0%
						77.6%	73.8%	67.2%	66.0%	64.4%	63.8%	69.5%	68.5%	63.6%	51.9%	49.5%	49.0%	Long-Term Debt Ratio	48.0%
						22.4%	26.2%	32.8%	34.0%	35.6%	36.2%	30.5%	31.5%	36.4%	37.5%	42.5%	43.0%	Common Equity Ratio	48.5%
						11758	12199	12863	12658	12146	12557	11362	10992	12883	16740	21850	22400	Total Capital ($mill)	24700
						10788	11732	12402	13597	9593.0	10502	11537	12307	13057	14044	20125	21175	Net Plant ($mill)	24600
						5.8%	6.1%	6.4%	6.8%	6.3%	6.7%	6.1%	5.8%	6.8%	3.4%	5.0%	6.0%	Return on Total Cap'l	6.5%
						14.1%	13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	4.6%	8.0%	9.5%	Return on Shr. Equity	10.0%
						14.1%	13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	5.3%	8.0%	9.5%	Return on Com Equity E	10.0%
						3.6%	3.8%	5.0%	5.5%	4.2%	4.5%	1.1%	NMF	4.7%	NMF	2.0%	3.5%	Retained to Com Eq	4.0%
						74%	72%	62%	60%	66%	67%	92%	103%	68%	NMF	81%	68%	All Div'ds to Net Prof	61%

CAPITAL STRUCTURE as of 3/31/19
Total Debt $14161 mill. **Due in 5 Yrs** NA
LT Debt $13759 mill. **LT Interest** $425 mill.
Incl. $914 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.1x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/18 $1516 mill.
Oblig $2013 mill.
Pfd Stock $1778 mill. **Pfd Div'd** $49 mill.
800,000 shs. 6.125%, cum., 977,500 shs. 7%, cum., all liquidation value $1000.
Common Stock 502,173,861 shs. as of 4/25/19
MARKET CAP: $14 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+3.1	+2.1	+2.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	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.)	+2.3	+1.7	+1.7
Fixed Charge Cov. (%)	219	269	167

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-4.0%	1.5%	6.5%
"Cash Flow"	.5%	--	8.0%
Earnings	-1.5%	-3.0%	12.5%
Dividends	5.5%	7.5%	2.5%
Book Value	6.5%	1.0%	13.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2016	1984	1574	1889	2081	7528.0
2017	2735	2143	2098	2638	9614.0
2018	3155	2186	2212	3036	10589
2019	3531	3000	3050	3669	13250
2020	4050	3150	3200	3800	14200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2016	.36	d.01	.41	.25	1.00
2017	.44	.31	.39	.43	1.57
2018	.38	d.17	.35	.18	.74
2019	.28	.35	.47	.40	1.50
2020	.45	.40	.55	.45	1.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.2475	.2475	.2475	.2475	.99
2016	.2575	.2575	.2575	.2575	1.03
2017	.2675	.2675	.2675	.2675	1.07
2018	.2775	.2775	.2775	.2775	1.11
2019	.2875	.2875			

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.5 million customers in Houston and environs, and gas utilities with 4.4 million customers in Texas, Minnesota, Arkansas, Louisiana, Oklahoma, Indiana, and Ohio. Owns 53.8% of Enable Midstream Partners. Has nonutility operations. Discontinued Texas Genco Holdings in '04. Acquired Vectren 2/19. Electric revenue breakdown: residential, 52%; commercial, 31%; industrial, 15%; other, 2%. Gas costs: 55% of revenues. '18 depreciation rate: 6.3%. Has 14,000 employees. Chairman: Milton Carroll. President & CEO: Scott M. Prochazka. Inc.: Texas. Address: 1111 Louisiana, P.O. Box 4567, Houston, Texas 77210-4567. Tel.: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy's Houston Electric subsidiary has filed a general rate case. The utility asked the Texas commission for an increase of $161 million, based on a return of 10.4% on a common-equity ratio of 50%. A ruling is due by October. This is Houston Electric's first general rate application in several years, since the utility benefits from regulatory mechanisms that enable it to recover certain transmission and distribution costs.

Other regulatory matters are pending or upcoming. Indiana Electric is seeking a total of $17.2 million from three regulatory mechanisms. On the gas side, increases totaling $72.0 million are being sought from regulatory mechanisms in six states. These are separate from a general rate case in Ohio, in which a "black box" settlement (with no specified ROE) has been reached calling for a $22.7 million hike. A ruling is expected in mid-2019. Finally, Minnesota Gas plans to file a general rate case in November.

Profits in 2019 won't reflect the company's earning power following its acquisition of Vectren earlier this year. Although CenterPoint is excluding merger-related expenses from its earnings target of $1.60-$1.70 a share, we *include* these in our estimate of $1.50 a share. These amounted to $114 million in the first quarter, which is roughly half of the expected full-year total. Also, CenterPoint didn't own Vectren in January, a seasonally strong month for gas utilities. Note that we include any mark-to-market gains or losses in our earnings presentation. These are ongoing in the energy-services unit.

Earnings in 2020 should wind up considerably higher. Merger-related costs are likely to be much lower, at an expected $15 million-$25 million. CenterPoint's target for merger-related cost reductions is $75 million-$100 million. The company's utilities should continue benefiting from rate relief and strong customer growth. Our estimate is within management's guidance of $1.75-$1.90 a share.

CenterPoint stock has a dividend yield that is above average for a utility. However, with the recent quotation near the midpoint of our 3- to 5-year Target Price Range, total return potential is unspectacular.

Paul E. Debbas, CFA *June 14, 2019*

(A) Diluted EPS. Excl. extraordinary gains (losses): '04, ($2.72); '05, 9¢; '11, $1.89; '12, (38¢); '13, (52¢); '15, ($2.69); '17, $2.56; losses on disc. ops.: '04, 37¢; '05, 1¢. '16 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. 5 declarations in '17. ■ Div'd reinv. plan avail. (C) Incl. intang. In '18: $5.65/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. (elec.) in '11: 10%, (gas): 9.45%-11.25%; earned on avg. com. eq., '18: 5.5%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	55

CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
93.35	27.1 (Trailing: 26.3; Median: 17.0)	1.60	1.8%

VALUE LINE

TIMELINESS **2** Lowered 5/24/19
SAFETY **2** New 6/5/15
TECHNICAL **3** Lowered 5/31/19
BETA .65 (1.00 = Market)

High:	23.2	23.3	28.1	29.7	32.6	40.8	52.7	61.1	70.0	86.4	93.4	95.6
Low:	14.6	14.7	18.7	24.0	26.6	30.6	37.5	44.4	52.3	63.0	66.4	77.6

Target Price Range
2022 | 2023 | 2024

2022-24 PROJECTIONS

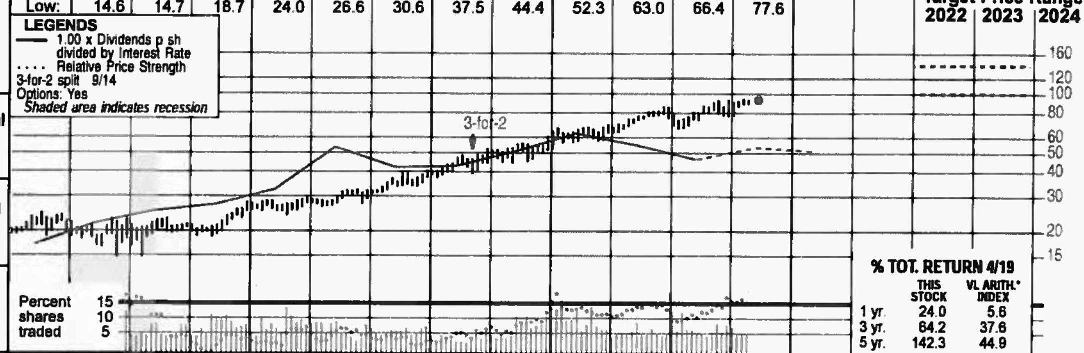
	Price	Gain	Ann'l Total Return
High	140	(+50%)	12%
Low	100	(+5%)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	0	0	0	1	5	0
to Sell	1	0	0	0	1	0	0	0	0

Institutional Decisions

	2Q2018	3Q2018	4Q2018
to Buy	74	66	87
to Sell	94	87	84
Hld's(000)	10445	10589	10581



% TOT. RETURN 4/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.0	5.6
3 yr.	64.2	37.6
5 yr.	142.3	44.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
19.11	20.70	26.02	23.05	25.41	28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	37.79	43.81	**42.65**	**45.70**	Revenues per sh	**63.75**
2.42	2.26	2.35	2.18	2.52	2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	5.42	6.47	**6.55**	**7.05**	"Cash Flow" per sh	**9.00**
1.17	1.09	1.18	1.15	1.29	1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	2.68	3.45	**3.45**	**3.70**	Earnings per sh A	**5.00**
.73	.75	.76	.77	.78	.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	**1.55**	**1.68**	Div'ds Decl'd per sh B■	**2.15**
1.39	2.07	3.74	4.87	3.08	3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	10.73	16.47	**9.90**	**10.30**	Cap'l Spending per sh	**11.80**
8.59	9.07	9.60	11.08	11.76	12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	29.75	31.65	**35.55**	**37.00**	Book Value per sh	**49.00**
8.49	8.60	8.82	10.03	10.17	10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	16.34	16.38	**17.00**	**17.50**	Common Shs Outst'g C	**20.00**
12.7	15.0	16.8	17.9	16.7	14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	27.8	22.9	*Bold figures are*		Avg Ann'l P/E Ratio	**24.0**
.72	.79	.89	.97	.89	.85	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24	*Value Line*		Relative P/E Ratio	**1.35**
4.9%	4.6%	3.8%	3.8%	3.6%	4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	1.7%	1.8%	*estimates*		Avg Ann'l Div'd Yield	**1.8%**
						268.8	427.5	418.0	392.5	444.3	498.8	459.2	498.9	617.6	717.5	**725**	**800**	Revenues ($mill)	**1275**
						15.9	26.1	27.6	28.9	32.8	36.1	40.2	44.7	43.8	56.6	**58.0**	**65.0**	Net Profit ($mill)	**100**
						41.8%	39.7%	39.4%	40.1%	40.2%	39.9%	39.5%	38.8%	39.5%	27.1%	**25.5%**	**26.0%**	Income Tax Rate	**27.0%**
						5.9%	6.1%	6.6%	7.4%	7.4%	7.2%	8.8%	9.0%	7.1%	7.9%	**8.0%**	**8.1%**	Net Profit Margin	**7.8%**
						32.0%	28.4%	31.4%	28.4%	29.7%	34.5%	29.4%	23.5%	28.9%	37.9%	**35.0%**	**38.0%**	Long-Term Debt Ratio	**30.0%**
						68.0%	71.6%	68.6%	71.6%	70.3%	65.5%	70.6%	76.5%	71.1%	62.1%	**65.0%**	**62.0%**	Common Equity Ratio	**70.0%**
						308.6	315.9	351.1	358.5	396.4	458.8	507.5	583.0	683.7	834.5	**930**	**1045**	Total Capital ($mill)	**1400**
						436.4	462.8	487.7	541.8	631.2	689.8	855.0	986.7	1126.0	1384.0	**1450**	**1610**	Net Plant ($mill)	**2000**
						6.1%	9.1%	8.9%	8.8%	8.8%	8.5%	8.9%	8.6%	7.3%	7.8%	**7.5%**	**7.5%**	Return on Total Cap'l	**8.0%**
						7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	**9.5%**	**10.0%**	Return on Shr. Equity	**10.0%**
						7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	**9.5%**	**10.0%**	Return on Com Equity	**10.0%**
						3.8%	6.6%	6.6%	6.4%	7.1%	7.4%	6.8%	6.1%	4.9%	6.7%	**5.0%**	**5.5%**	Retained to Com Eq	**6.0%**
						50%	42%	42%	43%	40%	38%	40%	39%	45%	39%	**45%**	**45%**	All Div'ds to Net Prof	**43%**

CAPITAL STRUCTURE as of 3/31/19
Total Debt $633.9 mill. **Due in 5 Yrs** $410.0 mill.
LT Debt $286.0 mill. **LT Interest** $15.0 mill.
(LT interest earned: 5.7x; total interest coverage: 5.7x) (34% of Cap'l)
Leases, Uncapitalized Annual rentals$2.4 mill.
Pfd Stock None
Pension Assets-12/18 $52.3 mill. **Oblig.** $70.1 mill.
Common Stock 16,397,017 shs. as of 4/30/19

MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2017	2018	3/31/19
Cash Assets	5.6	6.1	8.0
Other	173.0	185.4	145.6
Current Assets	178.6	191.5	153.6
Accts Payable	74.7	129.8	75.3
Debt Due	260.4	306.4	347.9
Other	77.9	92.0	85.4
Current Liab.	413.0	528.2	508.6
Fix. Chg. Cov.	749%	636%	645%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	4.0%	5.0%	9.5%
"Cash Flow"	9.0%	7.5%	8.0%
Earnings	9.0%	8.0%	9.0%
Dividends	5.0%	6.0%	9.0%
Book Value	10.0%	10.5%	9.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	146.3	102.3	108.3	142.0	498.9
2017	185.2	125.1	126.9	180.4	617.6
2018	239.4	136.7	140.3	201.1	717.5
2019	227.6	*145*	*155*	*197.4*	*725*
2020	*252*	*165*	*173*	*210*	*800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.33	.52	.29	.73	2.86
2017	1.17	.37	.42	.72	2.68
2018	1.64	.39	.34	1.08	3.45
2019	1.74	*.47*	*.45*	*.79*	*3.45*
2020	*1.85*	*.53*	*.51*	*.81*	*3.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.27	.27	.288	.288	1.12
2016	.288	.288	.305	.305	1.19
2017	.305	.305	.325	.325	1.26
2018	.325	.325	.37	.37	1.39
2019	.37	.37	.405		

BUSINESS: Chesapeake Utilities Corporation consists of two units: Regulated Energy and Unregulated Energy. The Regulated Energy segment (45% of 2018 revenues) distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation (55% of 2018 revenues) wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Officers and directors own 4.2% of common stock; T. Rowe Price, 13.7%; BlackRock, 9.2% (4/19 Proxy). CEO: Jeffry M. Householder. Inc.: Delaware. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities Corp. got off to a decent start in 2019. In fact, first-quarter earnings advanced about 6%, to $1.74 a share, versus last year's figure of $1.64. This was brought about by improved performances from both the Regulated Energy unit and Unregulated Energy division. Another plus was a lower effective income tax rate. Still, given the difficult fourth-quarter comparison, it seems that the bottom line may come in flat, at $3.45 a share, for the entire year. But supported partly by incremental benefits from earlier acquisitions, 2020 share net stands to grow some 7%, to $3.70.

Capital expenditures for this year are anticipated to be approximately $168.2 million. (That's nearly 38% lower than 2018's level of $269.8 million.) Roughly 80% of the budget is dedicated to the Regulated Energy operation, with a focus on the natural gas distribution and transmission businesses. Chesapeake's balance sheet (more detail below) appears quite adequate to support those and other initiatives.

Finances are in solid shape. At the end of the first quarter, cash on hand stood at $8 million. Long-term debt was just 34% of total capital, and short-term obligations did not appear to be a big obstacle. The energy firm also possesses five unsecured bank credit facilities totaling $220 million. Lastly, it has access to $150 million of short-term debt under a revolver that's available until October, 2020.

The quarterly dividend was raised 9.5%, to $0.405 a share. That reflects the company's confidence in its earnings prospects. Indeed, our projections out to 2022-2024 indicate that additional steady increases in the distribution will take place. The payout ratio over that span ought to be in the neighborhood of 43%, which is quite reasonable. However, the dividend yield is not exciting when stacked against those of other equities in *Value Line's* Natural Gas Utility Industry.

Chesapeake stock has been riding high over the past few months. It seems that the decent first-quarter profits are a factor behind that move. Consequently, the Timeliness rank resides at 2 (Above Average). But long-term capital gains potential now looks unappealing.

Frederick L. Harris, III *May 31, 2019*

(A) Diluted shrs. Excludes nonrecurring items: '08, d7¢; '15, 6¢; '17, 87¢. Excludes discontinued operations: '03, d9¢; '04, d1¢. Next earnings report due early Aug.
(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.
(C) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	75
Price Growth Persistence	90
Earnings Predictability	90

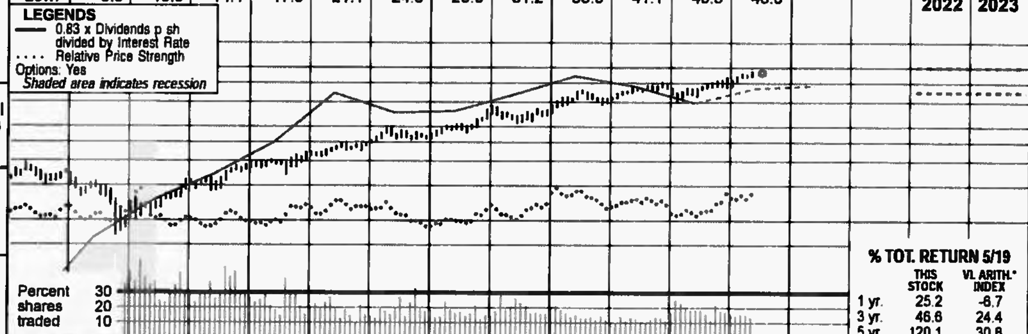
CMS ENERGY CORP. NYSE-CMS

RECENT PRICE **56.58** | P/E RATIO **22.6** (Trailing: 25.6 / Median: 17.0) | RELATIVE P/E RATIO **1.37** | DIV'D YLD **2.8%** | VALUE LINE

TIMELINESS 3 Lowered 1/11/19
SAFETY 2 Raised 3/21/14
TECHNICAL 3 Lowered 5/31/19
BETA .55 (1.00 = Market)

High:	17.5	16.1	19.3	22.4	25.0	30.0	36.9	38.7	46.3	50.8	53.8	57.7
Low:	8.3	10.0	14.1	17.0	21.1	24.6	26.0	31.2	35.0	41.1	40.5	48.0

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+5%)	4%
Low	45	(-20%)	-2%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	12	0	9	0
to Sell	2	0	1	1	0	0	1	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	231	268	298
to Sell	235	236	233
Hld's(000)	264290	261889	261163

% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.2	-6.7
3 yr.	46.6	24.4
5 yr.	120.1	30.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	23.37	24.25	**24.90**	**25.35**	Revenues per sh	**27.00**
2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	5.29	5.61	**6.00**	**6.35**	"Cash Flow" per sh	**7.50**
d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	2.17	2.32	**2.50**	**2.70**	Earnings per sh A	**3.25**
--	--	--	--	.20	.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	1.33	1.43	**1.53**	**1.64**	Div'd Decl'd per sh B ■	**2.00**
3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	5.91	7.32	**7.70**	**8.35**	Cap'l Spending per sh	**7.50**
9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	15.77	16.78	**17.90**	**19.35**	Book Value per sh C	**24.50**
161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	281.65	283.37	**285.00**	**288.00**	Common Shs Outst'g D	**297.00**
--	12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	21.3	20.3	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
--	.66	.67	1.20	1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.10	1.07	1.10	*Value Line*		Relative P/E Ratio	**.90**
--	--	--	--	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	2.9%	3.0%	*estimates*		Avg Ann'l Div'd Yield	**3.8%**

CAPITAL STRUCTURE as of 3/31/19
Total Debt $12068 mill. **Due in 5 Yrs** $4151 mill.
LT Debt $11196 mill. **LT Interest** $497 mill.
Incl. $91 mill. capitalized leases.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $16 mill.
Pension Assets-12/18 $2247 mill. **Oblig** $2512 mill.
Pfd Stock $37 mill. **Pfd Div'd** $2 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00.
Common Stock 283,753,895 shs. **as of 4/8/19**
MARKET CAP: $16 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
6205.0	6432.0	6503.0	6312.0	6566.0	7179.0	6456.0	6399.0	6583.0	6873.0	**7100**	**7300**	Revenues ($mill)	**8000**
231.0	356.0	384.0	413.0	454.0	479.0	525.0	553.0	610.0	659.0	**720**	**785**	Net Profit ($mill)	**1015**
34.6%	38.1%	36.8%	39.4%	39.9%	34.3%	34.0%	33.1%	31.2%	14.9%	**15.0%**	**15.0%**	Income Tax Rate	**15.0%**
13.0%	2.2%	2.6%	2.9%	2.0%	2.3%	2.7%	3.1%	1.1%	1.4%	**1.0%**	**1.0%**	AFUDC % to Net Profit	**1.0%**
67.9%	70.1%	66.9%	67.9%	67.5%	68.7%	68.3%	67.1%	67.3%	69.0%	**68.0%**	**66.5%**	Long-Term Debt Ratio	**63.5%**
29.0%	29.5%	32.6%	31.6%	32.2%	31.0%	31.4%	32.6%	32.4%	30.7%	**32.0%**	**33.0%**	Common Equity Ratio	**36.5%**
8977.0	9473.0	9279.0	10101	10730	11846	12534	13040	13692	15476	**16025**	**16800**	Total Capital ($mill)	**20000**
9682.0	10069	10633	11551	12246	13412	14705	15715	16761	18126	**19350**	**20700**	Net Plant ($mill)	**23800**
4.7%	5.8%	6.3%	5.9%	6.0%	5.7%	5.7%	5.8%	5.9%	5.6%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
8.0%	12.5%	12.5%	12.8%	13.0%	12.9%	13.2%	12.9%	13.6%	13.8%	**14.0%**	**14.0%**	Return on Shr. Equity	**14.0%**
8.5%	12.5%	12.6%	12.9%	13.1%	13.0%	13.3%	13.0%	13.7%	13.8%	**14.0%**	**14.0%**	Return on Com Equity E	**14.0%**
4.1%	6.9%	5.6%	5.0%	5.2%	5.0%	5.2%	4.8%	5.2%	5.3%	**5.5%**	**5.5%**	Retained to Com Eq	**6.0%**
54%	46%	55%	61%	60%	62%	61%	63%	62%	62%	**61%**	**60%**	All Div'ds to Net Prof	**59%**

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+1.7	-1.4	+2.2
Avg. Indust. Use (MWH)	6031	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.76	8.26	7.63
Capacity at Peak (Mw)	8331	NA	NA
Peak Load, Summer (Mw)	8227	7634	8084
Annual Load Factor (%)	54.6	NA	NA
% Change Customers (yr-end)	+.5	+1.2	+.3
Fixed Charge Cov. (%)	292	301	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-2.5%	-1.0%	2.5%
"Cash Flow"	4.5%	6.5%	6.0%
Earnings	10.0%	7.0%	7.0%
Dividends	21.5%	7.0%	7.0%
Book Value	4.5%	5.5%	7.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1801	1371	1587	1640	6399
2017	1829	1449	1527	1778	6583
2018	1953	1492	1599	1829	6873
2019	2059	**1541**	**1650**	**1850**	**7100**
2020	**2100**	**1600**	**1700**	**1900**	**7300**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.59	.45	.67	.28	1.98
2017	.71	.33	.61	.52	2.17
2018	.86	.49	.59	.38	2.32
2019	.75	**.55**	**.70**	**.50**	**2.50**
2020	**.85**	**.55**	**.75**	**.55**	**2.70**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.29	.29	.29	.29	1.16
2016	.31	.31	.31	.31	1.24
2017	.3325	.3325	.3325	.3325	1.33
2018	.3575	.3575	.3575	.3575	1.43
2019	.3825	.3825			

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.8 million gas customers. Has 1,034 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 45%; commercial, 34%; industrial, 15%; other, 6%. Generating sources: coal, 26%; gas, 14%; other, 3%; purchased, 57%. Fuel costs: 44% of revenues. '18 reported deprec. rates: 3.9% electric, 2.9% gas, 10.1% other. Has 8,000 full-time employees. Chairman: John G. Russell. President & CEO: Patricia K. Poppe. Inc.: Michigan. Address: One Energy Plaza, Jackson, MI 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has a gas rate case pending. Consumers Energy is seeking an increase of $204 million (revised from $229 million), based on a return of 10.75% on a common-equity ratio of 52.5%. The utility also requested decoupling of gas revenues and volume, and a regulatory mechanism to recover certain capital investments without having to file a general rate case. The staff of the Michigan Public Service Commission (MPSC) recommended an increase of $146 million, based on a return of 9.65% on a common-equity ratio of 52%. The staff supported the decoupling proposal, but not the investment recovery mechanism. An administrative law judge will make a recommendation this summer, and the MPSC's order is due by the end of September.

The MPSC was expected to rule on the company's integrated resource proposal shortly after this report went to press. The agreement would see Consumers Energy retire two coal-fired units, add 1,100 mw of solar energy, and increase spending on energy efficiency. Half of the new solar capacity would come through purchased-power agreements, but these would come with an incentive mechanism that would initially add $3 million to pretax income. Under this agreement, Consumers Energy would not file an electric rate case until 2020.

Two more rate cases are coming in the next several months. Consumers Energy plans to put forth another gas application in late 2019. The utility's next electric filing will probably come in early 2020. Frequent regulatory activity is necessary because Consumers Energy has a large system with a lot of old equipment.

We expect a continuation of steady earnings growth in 2019 and 2020. Rate relief and effective expense controls are helping boost the bottom line. Our 2019 estimate is within CMS Energy's typically narrow range of $2.47-$2.51 a share. Management's goal for annual profit growth is 6%-8%, and our 2020 estimate would produce an increase of 8%.

This stock is expensively priced. The relative price-earnings ratio is well above the historical level. The dividend yield is low for a utility, and 3- to 5-year total return potential is minuscule.

Paul E. Debbas, CFA *June 14, 2019*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); 10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); 11, 1¢; '12, 3¢. '16 EPS don't sum due to rounding. Next earnings report due late July. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '18: $6.15/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '18: 10%; earn. on avg. com. eq. '18: 14.3%. Reg. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	90

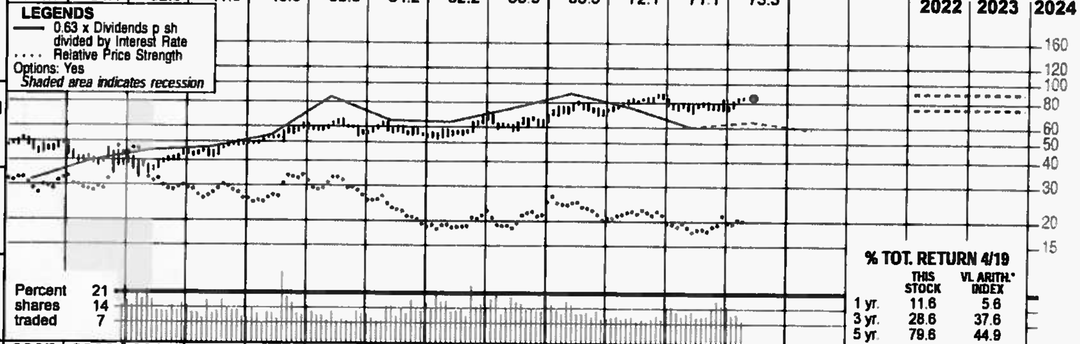
CON. EDISON NYSE-ED

RECENT PRICE **85.21** | P/E RATIO **20.5** (Trailing: 19.0, Median: 15.0) | RELATIVE P/E RATIO **1.20** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS 3 Lowered 3/8/19
SAFETY 1 New 7/27/90
TECHNICAL 2 Lowered 5/10/19
BETA .45 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	49.3	46.3	51.0	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9	86.5
Low:	34.1	32.6	41.5	48.6	53.6	54.2	52.2	56.9	63.5	72.1	71.1	73.3

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



Target Price Range 2022 | 2023 | 2024

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+5%)	5%
Low	75	(-10%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	10	8	8	10	8	8	10	8	8
Options	3	0	0	3	0	0	3	12	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2018	3Q2018	4Q2018
to Buy	338	314	423
to Sell	353	364	313
Hld's(000)	183175	181306	192114

Percent shares traded 21 14 7

% TOT. RETURN 4/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.6	5.6
3 yr.	28.6	37.6
5 yr.	79.6	44.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.82	38.43	*38.75*	*40.15*	Revenues per sh	*43.50*
5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	8.92	*9.05*	*9.85*	"Cash Flow" per sh	*11.50*
2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	4.55	*4.15*	*4.45*	Earnings per sh A	*5.00*
2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	2.86	*2.96*	*3.06*	Div'd Decl'd per sh B ■	*3.40*
5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	11.11	10.89	*10.85*	*12.45*	Cap'l Spending per sh	*12.50*
28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	49.74	52.11	*53.00*	*54.50*	Book Value per sh C	*59.75*
225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	310.00	321.00	*334.00*	*335.00*	Common Shs Outst'g D	*338.00*
14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8	17.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	1.00	.92	*Value Line*		Relative P/E Ratio	*.90*
5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 3/31/19
Total Debt $20397 mill. **Due in 5 Yrs** $4917 mill.
LT Debt $16933 mill. **LT Interest** $770 mill.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $72 mill.

Pension Assets-12/18 $13450 mill.
Oblig $14449 mill.

Pfd Stock None

Common Stock 327,053,801 shs.
as of 4/30/19
MARKET CAP: $28 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
13032	13325	12938	12188	12381	12919	12554	12075	12033	12337	*12950*	*13450*	Revenues ($mill)	*14700*
868.0	992.0	1062.0	1141.0	1157.0	1066.0	1193.0	1189.0	1266.0	1424.0	*1370*	*1490*	Net Profit ($mill)	*1735*
34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	33.6%	35.3%	36.6%	20.1%	*24.0%*	*22.0%*	Income Tax Rate	*19.5%*
2.6%	2.4%	1.6%	.5%	.5%	.3%	.7%	1.3%	1.5%	1.5%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
48.5%	48.6%	46.5%	45.9%	46.1%	48.0%	47.9%	50.8%	48.9%	51.1%	*51.5%*	*51.0%*	Long-Term Debt Ratio	*51.0%*
50.4%	50.4%	52.5%	54.1%	53.9%	52.0%	52.1%	49.2%	51.1%	48.9%	*48.5%*	*49.0%*	Common Equity Ratio	*49.0%*
20330	21952	21794	21933	22735	24207	25058	29033	30149	34221	*36400*	*37425*	Total Capital ($mill)	*41100*
22464	23863	25093	26939	28436	29827	32209	35216	37600	41749	*43725*	*46100*	Net Plant ($mill)	*52700*
5.7%	5.9%	6.2%	6.5%	6.4%	5.6%	6.0%	5.3%	5.4%	5.3%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
8.3%	8.8%	9.1%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.5%*
8.4%	8.9%	9.2%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	*7.5%*	*8.0%*	Return on Com Equity E	*8.5%*
2.5%	3.2%	3.1%	3.6%	3.6%	2.6%	3.5%	3.0%	3.0%	3.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
71%	65%	66%	62%	62%	69%	61%	64%	63%	59%	*71%*	*69%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.4	-2.8	+2.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	13731	14156
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	352	354	306

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-2.0%	-2.0%	*2.0%*
"Cash Flow"	4.0%	3.5%	*5.5%*
Earnings	2.5%	2.0%	*3.0%*
Dividends	2.0%	2.5%	*3.5%*
Book Value	4.0%	4.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	3157	2794	3417	2707	12075
2017	3228	2633	3211	2961	12033
2018	3364	2696	3328	2949	12337
2019	3514	*2836*	*3500*	*3100*	*12950*
2020	*3650*	*2950*	*3650*	*3200*	*13450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.05	.77	1.47	.64	3.94
2017	1.27	.57	1.48	.78	4.10
2018	1.37	.60	1.52	1.06	4.55
2019	1.31	*.54*	*1.50*	*.80*	*4.15*
2020	*1.40*	*.60*	*1.60*	*.85*	*4.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.65	.65	.65	.65	2.60
2016	.67	.67	.67	.67	2.68
2017	.69	.69	.69	.69	2.76
2018	.715	.715	.715	.715	2.86
2019	.74				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.7 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16. Purchases most of its power. Fuel costs: 24% of revenues. '18 reported depreciation rates: 2.9%-3.1%. Has 15,300 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison's largest utility subsidiary has a general rate case pending. Consolidated Edison Company of New York is seeking electric rate increases of $473 million in 2020, $359 million in 2021, and $249 million in 2022, and gas tariff hikes of $201 million in 2020, $124 million in 2021, and $154 million in 2022. The utility wants to place capital investments in the rate base and recover higher expenses. The application is based on a 9.75% return on a 50% common-equity ratio. An order is expected by year-end.

The regulators approved a settlement for Orange & Rockland. An electric rate hike of $13.4 million took effect at the start of 2019. This will be followed by increases of $8.0 million next year and $5.8 million in 2021. On the gas side, rates were reduced $7.5 million at the start of this year, and will be boosted by $3.6 million in 2020 and $0.7 million in 2021. The allowed return on equity is 9% and the common-equity ratio is 48%.

Our 2019 earnings estimate requires an explanation. Our estimate of $4.15 a share is below ConEd's targeted range of $4.25-$4.45 because the company excludes from its guidance a $0.20-a-share charge that it will record this year associated with an acquisition of renewable-energy assets in late 2018. Note that a gain associated with the same acquisition boosted earnings by $0.26 a share in the fourth quarter of 2018, making the comparison difficult.

There is a risk concerning the company's renewable-energy business. Con-Ed has contracts with Pacific Gas and Electric for 680 megawatts of capacity. PG&E is operating under Chapter 11 bankruptcy protection. Thus, it may reject the contracts, and the lenders for the related project debt may declare principal and interest due immediately. The contracts are expected to provide $0.03-$0.04 of share profits this year. So far, this uncertainty does not appear to be weighing on the price of ConEd's stock.

The dividend yield of this top-quality stock is about average for a utility. Like most utility issues, the recent quotation is within our 3- to 5-year Target Price Range. Thus, total return potential is low.

Paul E. Debbas, CFA *May 17, 2019*

(A) Diluted EPS. Excl. nonrec. gains (losses): '03, (45¢); '13, (32¢); '14, 9¢; '16, 15¢; '17, 84¢; '18, (13¢); gain on discontinued operations: '08, $1.01. '16 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '18: $20.38/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '17: 9.0%; O&R in '15: 9.0%; earned on avg. com. eq., '18: 8.8%. Regulatory Climate: Below Average.

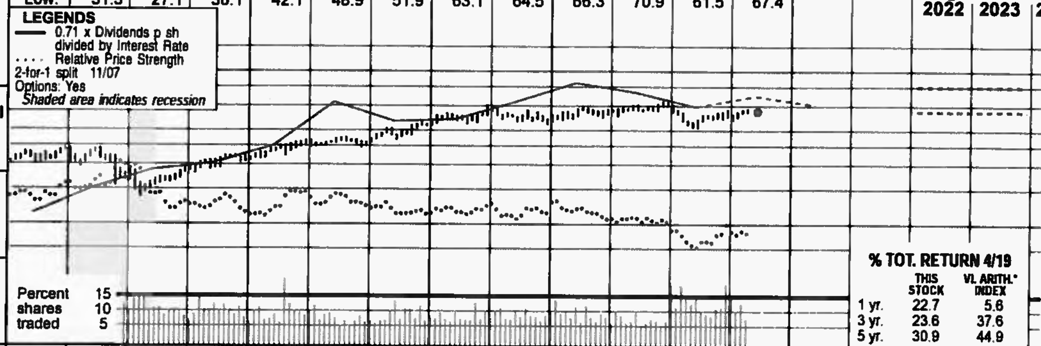
Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	95

DOMINION ENERGY NYSE-D

RECENT PRICE 75.04 | P/E RATIO 31.9 (Trailing: 35.1 Median: 20.0) | RELATIVE P/E RATIO 1.87 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 3 Lowered 3/22/19
SAFETY 2 Raised 9/11/98
TECHNICAL 1 Raised 5/17/19
BETA .55 (1.00 = Market)

High:	48.5	39.8	45.1	53.6	55.6	68.0	80.9	79.9	79.0	85.3	81.7	77.9
Low:	31.3	27.1	36.1	42.1	48.9	51.9	63.1	64.5	66.3	70.9	61.5	67.4



Target Price Range
2022 | 2023 | 2024

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+35%)	11%
Low	75	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	0	0	1	0	0	2
Options	0	0	0	0	0	0	14	9	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	2Q2018	3Q2018	4Q2018
to Buy	525	510	610
to Sell	522	501	457
Hld's(000)	440764	440541	466553

% TOT. RETURN 4/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.7	5.6
3 yr.	23.6	37.6
5 yr.	30.9	44.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
18.57	20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.53	19.63	**20.85**	**22.25**	Revenues per sh	**23.25**
3.97	4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	6.90	6.48	**6.15**	**8.50**	"Cash Flow" per sh	**9.50**
1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.53	3.25	**2.35**	**4.50**	Earnings per sh A	**5.00**
1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.04	3.34	**3.67**	**3.76**	Div'd Decl'd per sh B ■	**4.05**
5.20	3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	8.54	6.25	**7.45**	**8.45**	Cap'l Spending per sh	**8.00**
16.20	16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	26.59	29.53	**34.75**	**35.90**	Book Value per sh C	**39.50**
650.40	680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	644.60	680.90	**808.00**	**816.00**	Common Shs Outst'g D	**840.00**
15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	22.2	21.8	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.87	.80	1.33	.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.12	1.18	*Value Line*		Relative P/E Ratio	**.95**
4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%	3.9%	4.7%	*estimates*		Avg Ann'l Div'd Yield	**4.7%**
						15131	15197	14379	13093	13120	12436	11683	11737	12586	13366	**16850**	**18150**	Revenues ($mill)	**19500**
						1585.0	1724.0	1603.0	1594.0	1806.0	1793.0	1899.0	2123.0	2244.0	2130.0	**1920**	**3695**	Net Profit ($mill)	**4170**
						33.2%	38.6%	34.6%	36.2%	33.0%	28.1%	32.0%	22.8%	27.2%	17.7%	**25.0%**	**17.0%**	Income Tax Rate	**17.0%**
						4.8%	5.9%	5.3%	5.7%	3.7%	4.5%	5.3%	7.5%	10.5%	6.3%	**8.0%**	**4.0%**	AFUDC % to Net Profit	**3.0%**
						57.5%	56.3%	59.8%	60.9%	61.9%	65.4%	65.1%	67.4%	64.4%	60.8%	**59.0%**	**57.0%**	Long-Term Debt Ratio	**60.0%**
						41.5%	42.8%	39.3%	38.2%	37.3%	34.6%	34.9%	32.6%	35.6%	39.2%	**41.0%**	**43.0%**	Common Equity Ratio	**40.0%**
						26923	28012	29097	27676	31229	33360	36280	44836	48090	51251	**68775**	**68425**	Total Capital ($mill)	**82800**
						25592	26713	29670	30773	32628	36270	41554	49964	53758	54560	**68525**	**72200**	Net Plant ($mill)	**81800**
						7.5%	7.7%	7.0%	7.5%	7.3%	6.6%	6.5%	6.0%	5.9%	5.5%	**4.0%**	**6.5%**	Return on Total Cap'l	**6.5%**
						13.9%	14.1%	13.7%	14.7%	15.2%	15.5%	15.0%	14.5%	13.1%	10.6%	**7.0%**	**12.5%**	Return on Shr. Equity	**12.5%**
						14.0%	14.2%	13.9%	14.9%	15.4%	15.4%	15.0%	14.5%	13.1%	10.6%	**7.0%**	**12.5%**	Return on Com Equity E	**12.5%**
						4.7%	5.3%	4.0%	3.5%	4.2%	3.3%	2.9%	2.7%	1.8%	NMF	**NMF**	**2.0%**	Retained to Com Eq	**2.5%**
						67%	63%	71%	77%	73%	79%	81%	81%	86%	103%	**NMF**	**83%**	All Div'ds to Net Prof	**82%**

CAPITAL STRUCTURE as of 3/31/19
Total Debt $42353 mill. **Due in 5 Yrs** $16636 mill.
LT Debt $36861 mill. **LT Interest** $1566 mill.
(LT interest earned: 2.3x)

Leases, Uncapitalized Annual rentals $64 mill.

Pension Assets-12/18 $7197 mill. **Oblig** $8500 mill.

Pfd Stock None

Common Stock 802,364,338 shs.
as of 4/12/19
MARKET CAP: $60 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	310	287	219

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-3.0%	-4.0%	*3.0%*
"Cash Flow"	2.5%	4.5%	*6.5%*
Earnings	3.0%	3.5%	*6.5%*
Dividends	7.5%	7.5%	*5.0%*
Book Value	4.5%	6.5%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2921	2598	3132	3086	11737
2017	3384	2813	3179	3210	12586
2018	3466	3088	3451	3361	13366
2019	3858	***3992***	***4500***	***4500***	***16850***
2020	***4550***	***4200***	***4700***	***4700***	***18150***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.88	.73	1.10	.73	3.44
2017	1.01	.62	1.03	.87	3.53
2018	.77	.82	1.22	.44	3.25
2019	d.34	***.49***	***1.15***	***1.05***	***2.35***
2020	***1.25***	***.95***	***1.20***	***1.10***	***4.50***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.6475	.6475	.6475	.6475	2.59
2016	.70	.70	.70	.70	2.80
2017	.755	.755	.755	.77	3.04
2018	.835	.835	.835	.835	3.34
2019	.9175				

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources) is a holding company for Virginia Power, North Carolina Power, & South Carolina E&G, which serve 3.4 mill. customers in VA, SC, & NC. Serves 3.3 mill. gas customers in OH, WV, UT, SC, & NC. Other ops. incl. independent power production. Acq'd Questar 9/16; SCANA 1/19. Elec. rev. breakdown: residential, 46%; commercial, 32%; industrial, 7%; other, 15%. Generating sources: gas, 33%; nuclear, 29%; coal, 13%; other, 6%; purchased, 19%. Fuel costs: 27% of revs. '18 reported deprec. rates: 2.4%-4.6%. Has 21,300 empls. Chairman, President & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dominionenergy.com.

We have slashed our 2019 earnings estimate for Dominion Energy. The company recorded a loss in the first quarter due to charges associated with the acquisition of SCANA at the start of 2019. (This is even after excluding writedowns of utility assets that amounted to $0.52 a share.) In addition, Dominion Energy will book a charge (to be determined) in the June quarter for an early retirement plan, which is part of a cost-cutting initiative. Note, too, that we also *include* in our presentation any gains or losses in the nuclear decommissioning trust for the company's nonregulated units. All told, we have reduced our earnings estimate from $4.30 a share to $2.35. We are assuming no unusual items in our 2020 estimate, which remains $4.50 a share.

The big earnings reduction should not obscure the good performance of the company's operations. Virginia Power benefits from regulatory mechanisms that enable it to recover much of its capital spending through riders on customers' bills. Dominion Energy's gas utilities are experiencing strong customer growth. Finally, it appears as if the company will be able to keep open its Millstone nuclear plant, as long as the Connecticut commission approves an agreement that will provide subsidies through above-market payments for the facility's output via a 10-year contract. Even so . . .

The dividend growth rate is slowing considerably. Regulatory changes by the Federal Energy Regulatory Commission have made Dominion Energy's midstream gas business less lucrative than it once was. Also, the payout ratio is high, even when the company's definition of "operating" earnings is used as the denominator. (Dominion Energy's targeted range of operating earnings, which excludes some items we include, is $4.05-$4.40 a share.)

The Atlantic Coast Pipeline continues to face delays stemming from litigation. The best-case scenario is that the project, 48%-owned by Dominion Energy, is fully operational in the spring of 2021 at a cost of $7.0 billion-$7.8 billion.

This stock has one of the highest dividend yields of any utility. Total return potential to 2022-2024 is above the utility average, despite slower dividend growth.

Paul E. Debbas, CFA *May 17, 2019*

(A) Diluted earnings. Excl. nonrec. gains (losses): '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); '17, $1.19; '18, 43¢; '19, (52¢); losses from disc. ops.: '06, 26¢; '07, 1¢; '10, 26¢; '12, 4¢; '13, 16¢. Next earnings report due early Aug. (B) Div'ds paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '18: $14.33/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earned on avg. com. eq., '18: 11.5%. Regulat. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

DTE ENERGY CO. NYSE-DTE

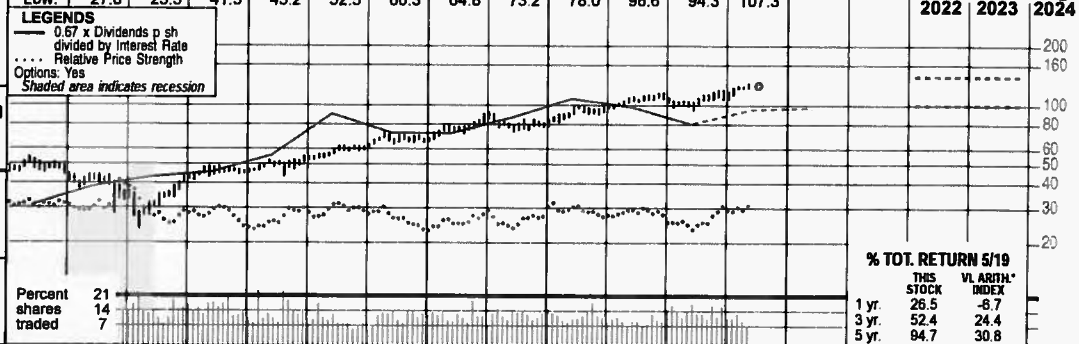
RECENT PRICE **126.39** | P/E RATIO **20.2** (Trailing: 19.8 / Median: 16.0) | RELATIVE P/E RATIO **1.22** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS 3 Lowered 6/14/19
SAFETY 2 Raised 12/21/12
TECHNICAL 3 Lowered 5/31/19
BETA .55 (1.00 = Market)

High:	45.3	45.0	49.1	55.3	62.6	73.3	90.8	92.3	100.4	116.7	121.0	130.0
Low:	27.8	23.3	41.3	43.2	52.5	60.3	64.8	73.2	78.0	96.6	94.3	107.3

Target Price Range
2022 | 2023 | 2024

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



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	140	(+10%)	6%
Low	100	(-20%)	-1%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	1	0	6	11	0	0
to Sell	3	0	0	3	0	0	2	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	265	311	334
to Sell	250	265	243
Hld's(000)	133183	129217	129236

% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.5	-8.7
3 yr.	52.4	24.4
5 yr.	94.7	30.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	70.28	78.12	*75.50*	*77.55*	Revenues per sh	86.50
6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	11.77	12.58	*12.75*	*13.65*	"Cash Flow" per sh	16.00
2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	5.73	6.17	*6.25*	*6.70*	Earnings per sh A	7.75
2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	3.36	3.59	*3.84*	*4.07*	Div'd Decl'd per sh B ■	4.80
4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	12.54	14.91	*18.75*	*12.75*	Cap'l Spending per sh	13.00
31.38	31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	53.03	56.27	*60.50*	*64.40*	Book Value per sh C	74.00
168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	179.39	181.93	*192.00*	*196.00*	Common Shs Outst'g D	200.00
13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	18.6	17.4	*Bold figures are*		Avg Ann'l P/E Ratio	15.5
.78	.85	.73	.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.94	.94	*Value Line*		Relative P/E Ratio	.85
5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	3.2%	3.3%	*estimates*		Avg Ann'l Div'd Yield	4.0%

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
8014.0	8557.0	8897.0	8791.0	9661.0	12301	10337	10630	12607	14212	*14500*	*15200*	Revenues ($mill)	18000
532.0	630.0	624.0	666.0	661.0	905.0	796.0	868.0	1029.0	1120.0	*1165*	*1300*	Net Profit ($mill)	1520
31.6%	32.7%	35.9%	29.8%	27.5%	28.5%	25.6%	24.5%	21.8%	8.1%	*11.5%*	*11.5%*	Income Tax Rate	8.0%
2.6%	1.6%	1.6%	3.0%	3.5%	4.1%	4.3%	3.6%	3.5%	3.8%	*4.0%*	*3.0%*	AFUDC % to Net Profit	2.0%
54.0%	51.3%	50.6%	48.8%	47.7%	50.0%	50.2%	55.6%	56.2%	54.2%	*53.0%*	*52.5%*	Long-Term Debt Ratio	53.5%
46.0%	48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	*47.0%*	*47.5%*	Common Equity Ratio	46.5%
13648	13811	14196	14387	15135	16670	17607	20280	21697	22371	*24600*	*26500*	Total Capital ($mill)	31600
12431	12992	13746	14684	15800	16820	18034	19730	20721	21650	*23975*	*25100*	Net Plant ($mill)	28300
5.7%	6.3%	5.9%	6.1%	5.7%	6.6%	5.7%	5.3%	5.9%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	6.0%
8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	*10.0%*	*10.5%*	Return on Shr. Equity	10.5%
8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	*10.0%*	*10.5%*	Return on Com Equity E	10.5%
2.9%	4.0%	3.4%	3.5%	2.7%	5.2%	3.4%	3.7%	4.6%	4.9%	*4.0%*	*4.0%*	Retained to Com Eq	4.0%
65%	57%	62%	61%	67%	52%	63%	61%	58%	55%	*62%*	*61%*	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 3/31/19
Total Debt $14431 mill. Due in 5 Yrs $4599 mill.
LT Debt $12776 mill. LT Interest $549 mill.
Incl. $756 mill. Trust Preferred Securities.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $42 mill.

Pension Assets-12/18 $4273 mill.
Oblig $5124 mill.

Pfd Stock None

Common Stock 183,632,324 shs.

MARKET CAP: $23 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+3.5	-3.1	+3.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	300	300	278

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	2.5%	5.5%	4.0%
"Cash Flow"	3.5%	3.5%	5.5%
Earnings	8.0%	8.0%	5.5%
Dividends	4.5%	6.5%	6.0%
Book Value	4.0%	4.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2566	2262	2928	2874	10630
2017	3236	2855	3245	3271	12607
2018	3753	3159	3550	3750	14212
2019	3514	*3250*	*3786*	*3950*	*14500*
2020	*3650*	*3400*	*4000*	*4150*	*15200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.37	.84	1.88	.74	4.83
2017	2.23	.99	1.51	1.00	5.73
2018	2.00	1.29	1.84	1.05	6.17
2019	2.19	*1.20*	*1.75*	*1.11*	*6.25*
2020	*2.30*	*1.25*	*1.85*	*1.30*	*6.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.69	.69	.69	.73	2.80
2016	.73	.73	.73	.77	2.96
2017	.825	.825	.825	.825	3.30
2018	.8825	.8825	.8825	.8825	3.53
2019	.945	.945			

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.2 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 47%; commercial, 34%; industrial, 13%; other, 6%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 61% of revenues. '18 reported deprec. rates: 3.7% electric, 2.7% gas. Has 10,600 employees. Chairman & CEO: Gerard M. Anderson. President & COO: Jerry Norcia. Inc.: MI. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary received a rate increase. DTE Electric's rates were raised $273 million, based on a 10% return on a 50% common-equity ratio. The order was constructive, considering that the utility had filed for a hike of $320 million. New tariffs took effect in May.

Two acquisitions of midstream gas assets are pending. DTE Energy agreed to pay $150 million-$200 million (the seller didn't want to disclose the exact amount) for a pipeline in Ohio that is near a pipeline the company put into service in 2018. Separately, DTE Energy plans to pay $275 million for a 30% stake in a gas gathering system in West Virginia in which the company already has a 55% interest. This asset, which DTE Energy initially acquired in 2016, has outperformed management's expectations.

We estimate a slight earnings increase in 2019. The comparison is difficult because favorable weather conditions aided both DTE Electric and DTE Gas in 2018. Our earnings estimate of $6.25 a share is within DTE Energy's targeted range of $5.97-$6.33 a share.

We look for a much sharper profit increase in 2020. DTE Electric will record a full year's effect of the aforementioned rate hike. DTE Gas doesn't have a general rate case pending, but the utility benefits from a regulatory mechanism that enables it to recover certain capital expenditures without the need for a rate application. On the nonutility side, some projects are coming on line, such as a cogeneration facility for Ford Motor, which is expected to come on line in the fourth quarter of 2019. Our $6.70-a-share estimate would produce profit growth at the upper end of management's annual goal of 5%-7%.

A gas-fired generating facility is under construction. DTE Electric is building an 1,100-megawatt plant at an expected cost of $952 million. The project is scheduled for completion in 2022. The company's capital spending plans are necessitating additions of common equity.

DTE Energy stock has an average valuation for a utility. The dividend yield and 3- to 5-year total return potential are each close to the norms for electric utilities.

Paul E. Debbas, CFA *June 14, 2019*

(A) Diluted EPS. Excl. nonrec. gains (losses). '03, (16¢); '05, (2¢), '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on disc. ops.: '03, 40¢, '04, (6¢) '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢). '17-'18 EPS don't sum due to rounding. Next egs. due late July. (B) Div'ds pd mid-Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. (C) Incl intang. In '18: $42.63/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '18: 10% elec.; in '16: 10.1% gas; earn. on avg. com. eq., '18: 11.3%. Regul. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	85

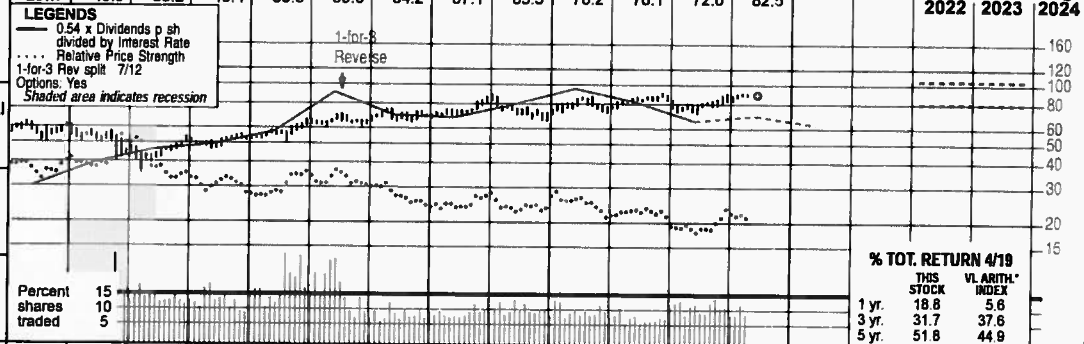
DUKE ENERGY NYSE-DUK

RECENT PRICE **89.26** | P/E RATIO **18.0** (Trailing: 21.3; Median: 18.0) | RELATIVE P/E RATIO **1.05** | DIV'D YLD **4.2%** | VALUE LINE

TIMELINESS 2 Raised 5/17/19
SAFETY 2 New 6/1/07
TECHNICAL 1 Raised 4/19/19
BETA .50 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	91.7
Low:	40.5	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+20%)	8%
Low	80	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	9	1
to Sell	0	2	0	0	0	0	0	4	1

Institutional Decisions

	2Q2018	3Q2018	4Q2018
to Buy	566	537	636
to Sell	597	607	598
Hld's(000)	431271	426795	442549

% TOT. RETURN 4/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.8	5.6
3 yr.	31.7	37.6
5 yr.	51.8	44.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
--	--	--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	**33.95**	**34.50**	Revenues per sh	**36.75**
--	--	--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	10.49	**11.70**	**12.25**	"Cash Flow" per sh	**13.75**
--	--	--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.13	**4.95**	**5.20**	Earnings per sh A	**5.75**
--	--	--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	**3.75**	**3.83**	Div'd Decl'd per sh B ■	**4.15**
--	--	--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	**15.15**	**14.30**	Cap'l Spending per sh	**12.75**
--	--	--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	**61.65**	**63.20**	Book Value per sh C	**68.50**
--	--	--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	**733.00**	**736.00**	Common Shs Outst'g D	**755.00**
--	--	--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	19.4	Bold figures are	Value Line	Avg Ann'l P/E Ratio	**16.0**
--	--	--	--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	1.05	estimates		Relative P/E Ratio	**.90**
--	--	--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%			Avg Ann'l Div'd Yield	**4.5%**

CAPITAL STRUCTURE as of 12/31/18
Total Debt $57939 mill. **Due in 5 Yrs** $21504 mill.
LT Debt $51123 mill. **LT Interest** $1866 mill.
Incl. $941 mill. capitalized leases.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $239 mill.
Pension Assets-12/18 $8233 mill. **Oblig** $7869 mill.

Pfd Stock None

Common Stock 727,010,882 shs.
as of 1/31/19
MARKET CAP: $65 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
12731	14272	14529	19624	24598	23925	23459	22743	23565	24521	**24900**	**25500**	Revenues ($mill)	**27800**
1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	2928.0	**3655**	**3875**	Net Profit ($mill)	**4375**
34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.2%	**12.0%**	**12.0%**	Income Tax Rate	**12.0%**
17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	13.0%	**9.0%**	**8.0%**	AFUDC % to Net Profit	**8.0%**
42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	**54.5%**	**55.5%**	Long-Term Debt Ratio	**56.0%**
57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	**44.5%**	**43.5%**	Common Equity Ratio	**43.5%**
37863	40457	41451	77307	79482	78088	77222	86609	90774	94940	**101950**	**106850**	Total Capital ($mill)	**119300**
37950	40344	42661	68558	69490	70046	75709	82520	86391	91694	**97825**	**103150**	Net Plant ($mill)	**114300**
4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.2%	**4.5%**	**4.5%**	Return on Total Cap'l	**5.0%**
6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	**8.0%**	**8.0%**	Return on Shr. Equity	**8.5%**
6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	**8.0%**	**8.0%**	Return on Com Equity E	**8.5%**
1.1%	2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	1.2%	1.0%	**2.0%**	**2.0%**	Retained to Com Eq	**2.5%**
84%	73%	72%	82%	76%	76%	79%	91%	83%	84%	**76%**	**74%**	All Div'ds to Net Prof	**72%**

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.3	-2.0	+3.9
Avg. Indust. Use (MWH)	2908	2914	2953
Avg. Indust. Revs. per KWH (¢)	NA	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.)	+1.4	+1.3	+1.4
Fixed Charge Cov. (%)	264	272	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	1.5%	1.0%	*1.5%*
"Cash Flow"	2.5%	4.5%	*5.5%*
Earnings	2.5%	.5%	*6.0%*
Dividends	7.0%	3.0%	*3.0%*
Book Value	1.0%	1.5%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	5377	5213	6576	5577	22743
2017	5729	5555	6482	5799	23565
2018	6135	5643	6628	6115	24521
2019	6163	**5750**	**6787**	**6200**	**24900**
2020	**6300**	**5900**	**6950**	**6350**	**25500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.83	.90	1.44	.54	3.71
2017	1.02	.98	1.36	.86	4.22
2018	1.17	.71	1.63	.61	4.13
2019	1.24	**1.05**	**1.70**	**.96**	**4.95**
2020	**1.30**	**1.10**	**1.80**	**1.00**	**5.20**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.795	.795	.825	.825	3.24
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018	.89	.89	.9275	.9275	3.64
2019	.9275				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 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, 44%; commercial, 28%; industrial, 14%; other, 14%. Generating sources: gas, 26%; nuclear, 26%; coal, 24%; other, 2%; purchased, 22%. Fuel costs: 31% of revs. '18 reported deprec. rate: 3.0%. Has 30,100 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.

Duke Energy's utilities in South Carolina received disappointing rate directives. Duke Energy Carolinas and Duke Energy Progress are awaiting written orders, but the commission granted an allowed return on equity of just 9.5% and disallowed recovery of costs for coal ash remediation. Duke will ask for a rehearing.

Other cases are pending or upcoming. In North Carolina, Piedmont Gas filed for an increase of $83 million (9.0%), based on a 10.6% return on a 52% common-equity ratio. The utility expects an order to take effect in late 2019. Duke Energy Indiana and Duke Energy Progress (in North Carolina) plan to file electric cases this year.

Earnings should improve in 2019 and 2020. Unusual items hurt the bottom line in 2018. Duke booked a penalty for coal-ash problems and a severance charge in the second and fourth periods, respectively. The company should benefit from rate relief and modest volume growth this year and next. Our 2019 share-net estimate is within Duke's guidance of $4.80-$5.20.

A gas pipeline project has been plagued by delays and cost overruns. When the Atlantic Coast Pipeline was proposed in 2014, this was expected to cost $4.5 billion-$5.0 billion and be in service in 2018. Litigation has tied up this project (47%-owned by Duke) in the courts, and the cost has soared to $7.0 billion-$7.8 billion. The pipeline is now expected to come on line in two phases, in 2020 and 2021.

Duke announced an asset sale. The company will receive $415 million, which will offset debt financing needs, for a minority stake in its nonutility renewable-energy assets. The deal is expected to close in the second half of 2019.

Dividend growth is slowing. The payout ratio is above Duke's goal of 65%-75%, and capital spending is higher than it was throughout most of this decade. The problems with the Atlantic Coast Pipeline are a factor, too. We estimate a boost of $0.02 a share (2.2%) quarterly.

This timely equity's dividend yield is nearly one percentage point above the utility mean. Offsetting this to some extent is the subpar dividend growth potential through early next decade. Even so, total return potential to 2022-2024 is better than most in this industry.

Paul E. Debbas, CFA *May 17, 2019*

(A) Diluted EPS Excl. nonrec. losses: '12, 70¢; '13 24¢; '14, 67¢; '17, 15¢; '18, 41¢, losses on disc. ops.: '14, 80¢, '16, 60¢; '18 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '18: $60.27/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '18 in NC: 9.9%, in '17 in SC: 10.1%; in '09 in OH: 10.63%, in '04 in IN: 10.3%; earned on avg. com eq., '18 6.8% Reg Clim.: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	85

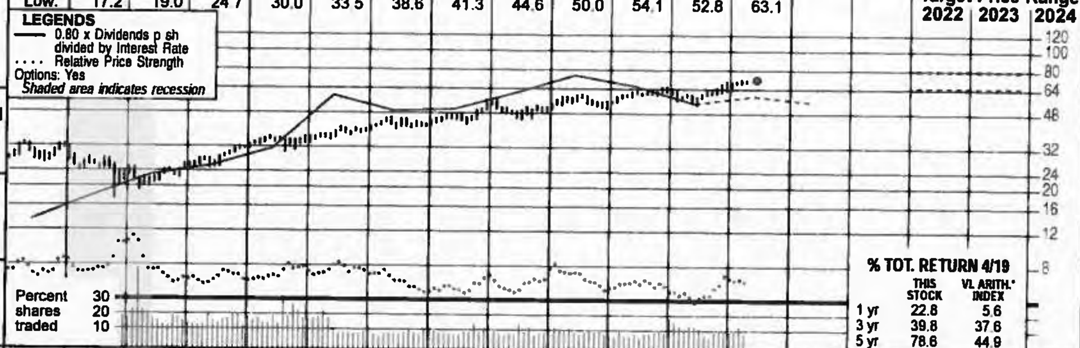
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 71.51 | P/E RATIO 20.7 (Trailing: 21.2 Median: 18.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Raised 5/10/19
SAFETY 1 Raised 5/22/15
TECHNICAL 2 Lowered 5/17/19
BETA .60 (1.00 = Market)

High:	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8	60.4	66.1	70.5	73.3
Low:	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1

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



Target Price Range 2022 | 2023 | 2024

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+10%)	6%
Low	65	(-10%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	10	0	0
to Sell	0	1	0	0	0	0	0	5	2

Institutional Decisions

	2Q2018	3Q2018	4Q2018
to Buy	241	266	320
to Sell	271	265	259
Hld's(000)	237438	238040	237152

Percent shares traded 30 20 10

% TOT. RETURN 4/19

	THIS STOCK	VL ARITH.* INDEX
1 yr	22.8	5.6
3 yr	39.8	37.6
5 yr	78.6	44.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
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	24.46	26.66	*26.55*	*26.80*	Revenues per sh	*27.25*
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	5.84	6.64	*7.25*	*7.55*	"Cash Flow" per sh	*8.25*
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	3.11	3.25	*3.45*	*3.65*	Earnings per sh A	*4.25*
.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*	*2.26*	Div'd Decl'd per sh B ■	*2.65*
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	7.41	7.96	*9.35*	*8.05*	Cap'l Spending per sh	*6.75*
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	34.99	36.25	*37.70*	*39.50*	Book Value per sh C	*46.75*
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	*318.50*	*323.00*	Common Shs Outst'g D	*350.00*
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	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	*Value Line*		Relative P/E Ratio	*.95*
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%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/19
Total Debt $15173 mill. **Due in 5 Yrs** $6683.1 mill.
LT Debt $12846 mill. **LT Interest** $513.8 mill.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $11.5 mill.
Pension Assets-12/18 $4573.9 mill.
Oblig $5520.0 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 317,461,097 shs. **as of 4/30/19**
MARKET CAP: $23 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	*8450*	*8650*	Revenues ($mill)	*9550*
335.6	377.8	400.3	533.0	793.7	827.1	886.0	949.8	995.5	1040.5	*1110*	*1185*	Net Profit ($mill)	*1460*
34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	*53.0%*	*53.0%*	Long-Term Debt Ratio	*52.0%*
41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	*46.5%*	*46.5%*	Common Equity Ratio	*47.5%*
8629.5	8741.8	8856.0	16675	17544	18738	19313	19697	23018	24474	*25900*	*27550*	Total Capital ($mill)	*34500*
8840.0	9567.7	10403	16605	17576	18647	19892	21351	23617	25610	*27525*	*29000*	Net Plant ($mill)	*32500*
5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
50%	49%	50%	72%	59%	58%	61%	60%	61%	62%	*62%*	*62%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-1.8	-2.6	+2.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.04	NA	NA
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. (%)	436	427	319

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-4.5%	2.0%	*1.5%*
"Cash Flow"	2.0%	5.0%	*5.5%*
Earnings	8.0%	7.0%	*5.5%*
Dividends	9.5%	8.0%	*5.5%*
Book Value	6.5%	5.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2055	1767	2039	1776	7639.1
2017	2105	1762	1988	1895	7752.0
2018	2288	1853	2271	2034	8448.2
2019	2416	*1834*	*2150*	*2050*	*8450*
2020	*2450*	*1900*	*2200*	*2100*	*8650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.77	.64	.83	.72	2.96
2017	.82	.72	.82	.75	3.11
2018	.85	.76	.91	.73	3.25
2019	.97	*.77*	*.91*	*.80*	*3.45*
2020	*1.03*	*.82*	*.95*	*.85*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.4175	.4175	.4175	.4175	1.67
2016	.445	.445	.445	.445	1.78
2017	.475	.475	.475	.475	1.90
2018	.505	.505	.505	.505	2.02
2019	.535				

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, 54%; commercial, 37%; industrial, 5%; other, 4%. Fuel costs: 37% of revs. '18 reported deprec. rate: 2.9%. Has 8,000 empls. Chairman, Pres & CEO: James J. Judge. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

We expect Eversource Energy to continue its steady earnings growth in 2019 and 2020. Three utilities will benefit from a full year's effect of rate hikes that were granted in 2018. Eversource's utilities in Connecticut will receive additional rate increases this year and next. The company receives rate relief annually for electric transmission through a forward-looking regulatory mechanism. Reductions in operating and maintenance expenses are continuing. Our 2019 share-earnings estimate is at the midpoint of Eversource's targeted range of $3.40-$3.50. We look for profit growth next year in line with management's 5%-7% goal.

Public Service of New Hampshire is planning to file a rate case. In 2018, the utility (which hasn't had a tariff hike for several years) earned a return on equity nearly two percentage points below the allowed 9.67%. PSNH has already asked for an interim increase of $33 million to take effect at the start of July, and plans to request a full increase of $70 million (including the $33 million interim boost) that would take effect in July of 2020.

Eversource is expanding its presence in offshore wind. The company already had a joint venture with Orsted, and paid $225 million for a 50% stake in some other projects with the same partner. If all goes well, this might increase Eversource's annual earnings growth above the 5%-7% range beyond 2023. However, offshore wind entails construction risk. This prompted one of the credit-rating agencies to place Eversource's rating on a negative outlook.

Financing needs are rising. Eversource has not issued equity for several years, but plans to issue $2 billion over the next five years, in addition to $100 million raised annually through its dividend reinvestment plan beginning this year. Debt financing will occur, as well. This will help fund Eversource's capital budget, and the company should maintain a strong balance sheet. We note as well that (unlike many utilities), the company is a cash taxpayer.

This timely stock has a moderate dividend yield, by utility standards. With the recent quotation well within our 2022-2024 Target Price Range, total return potential is just modest.

Paul E. Debbas, CFA *May 17, 2019*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. Next earnings report due early Aug. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '18: $28.59/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (gas) '16, 9.8%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '10, 9.67%; earned on avg. com. eq., '18: 9.2%. Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	95

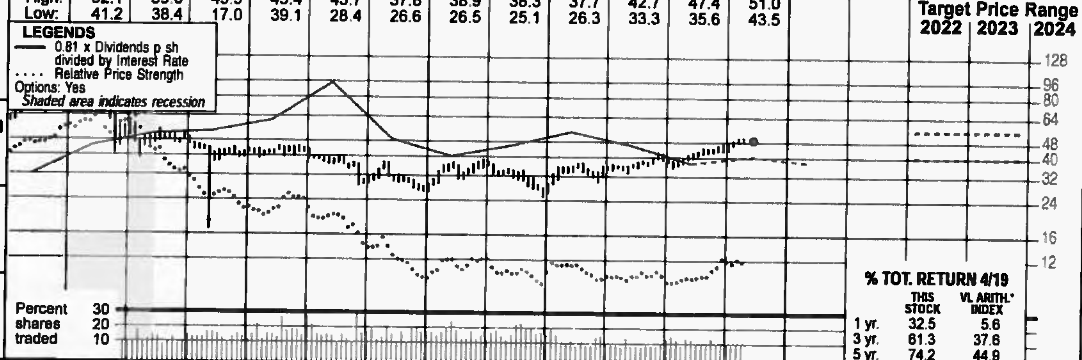
EXELON CORP. NYSE-EXC

RECENT PRICE 49.08 | P/E RATIO 15.6 (Trailing: 20.4 Median: 14.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Lowered 5/3/19
SAFETY 2 Raised 5/17/19
TECHNICAL 2 Raised 4/26/19
BETA .70 (1.00 = Market)

High:	92.1	59.0	49.9	45.4	43.7	37.8	38.9	38.3	37.7	42.7	47.4	51.0
Low:	41.2	38.4	17.0	39.1	28.4	26.6	26.5	25.1	26.3	33.3	35.6	43.5

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+10%)	6%
Low	40	(-20%)	-1%

Insider Decisions

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

Institutional Decisions

	2Q2018	3Q2018	4Q2018
to Buy	416	409	447
to Sell	363	389	413
Hld's(000)	754174	755138	771331

% TOT. RETURN 4/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	32.5	5.6
3 yr.	61.3	37.6
5 yr.	74.2	44.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
24.09	21.85	23.05	23.37	28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	37.17	**39.15**	**41.05**	Revenues per sh	**48.00**
5.06	5.68	6.19	6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.01	8.37	8.24	**9.30**	**9.75**	"Cash Flow" per sh	**11.50**
2.44	2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	2.78	2.07	**3.15**	**3.35**	Earnings per sh A	**4.00**
.96	1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	1.31	1.38	**1.45**	**1.53**	Div'd Decl'd per sh B ■	**1.80**
2.98	2.89	3.25	3.61	4.05	4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	9.26	7.87	7.84	**7.55**	**7.30**	Cap'l Spending per sh	**7.25**
12.95	14.19	13.69	14.89	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	30.99	31.77	**33.50**	**35.40**	Book Value per sh C	**41.75**
656.37	664.19	666.37	669.86	660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	963.34	968.19	**971.00**	**974.00**	Common Shs Outst'g D	**983.00**
11.8	13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	13.4	20.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**12.0**
.67	.69	.82	.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.98	.87	1.09	*estimates*		Relative P/E Ratio	**.65**
3.4%	3.5%	3.2%	2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	3.5%	3.3%			Avg Ann'l Div'd Yield	**3.8%**

CAPITAL STRUCTURE as of 3/31/19
Total Debt $37112 mill. **Due in 5 Yrs** $11576 mill.
LT Debt $33350 mill. **LT Interest** $1417 mill.
Includes $390 mill. nonrecourse transition bonds.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $140 mill.

Pension Assets-12/18 $16678 mill.
Oblig $20692 mill.
Pfd Stock None

Common Stock 970,954,879 shs.

MARKET CAP: $48 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
17318	18644	18924	23489	24888	27429	29447	31360	33531	35985	**38000**	**40000**	Revenues ($mill)	**47200**
2844.0	2567.0	2499.0	1579.0	1999.0	1826.0	2282.0	1677.0	2636.0	2010.0	**3055**	**3260**	Net Profit ($mill)	**4050**
38.8%	39.2%	36.8%	32.4%	36.5%	27.2%	32.2%	38.5%	34.2%	5.4%	**24.0%**	**24.0%**	Income Tax Rate	**24.0%**
2.3%	2.1%	3.0%	5.8%	4.5%	5.5%	5.4%	12.3%	6.5%	7.0%	**5.0%**	**5.0%**	AFUDC % to Net Profit	**4.0%**
47.2%	46.8%	45.7%	45.8%	44.4%	46.7%	48.3%	55.5%	52.2%	52.8%	**50.0%**	**51.0%**	Long-Term Debt Ratio	**49.0%**
52.4%	52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	**50.0%**	**49.0%**	Common Equity Ratio	**51.0%**
24112	25651	26661	40057	41196	42811	50272	58053	62422	65229	**64775**	**70200**	Total Capital ($mill)	**80600**
27341	29941	32570	45186	47330	52087	57439	71555	74202	76707	**78575**	**79900**	Net Plant ($mill)	**82100**
13.3%	11.4%	10.6%	5.1%	5.9%	5.3%	5.5%	4.1%	5.3%	4.2%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.0%**
22.3%	18.8%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	**9.5%**	**9.5%**	Return on Shr. Equity	**10.0%**
22.5%	18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	**9.5%**	**9.5%**	Return on Com Equity E	**10.0%**
11.5%	8.7%	7.7%	NMF	3.2%	3.3%	4.5%	1.9%	4.7%	2.2%	**5.0%**	**5.0%**	Retained to Com Eq	**5.5%**
49%	54%	56%	109%	63%	59%	49%	70%	47%	66%	**44%**	**44%**	All Div'ds to Net Prof	**43%**

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+25.8	-3.0	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Nuclear Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+33.7	+.9	NA
Fixed Charge Cov. (%)	238	282	236

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	3.0%	4.5%	*5.5%*
"Cash Flow"	1.0%	3.0%	*6.5%*
Earnings	-5.5%	-3.5%	*10.5%*
Dividends	-3.5%	-7.0%	*5.5%*
Book Value	7.0%	4.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	7573	6910	9002	7875	31360
2017	8757	7623	8769	8382	33531
2018	9693	8076	9403	8813	35985
2019	9477	**8723**	**10200**	**9600**	**38000**
2020	**10000**	**9250**	**10700**	**10050**	**40000**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.26	.45	.76	.32	1.80
2017	.83	.44	.95	.56	2.78
2018	.60	.56	.76	.16	2.07
2019	.93	**.57**	**1.05**	**.60**	**3.15**
2020	**.95**	**.65**	**1.10**	**.65**	**3.35**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.31	.31	.31	.31	1.24
2016	.31	.318	.318	.318	1.26
2017	.328	.328	.328	.328	1.31
2018	.345	.345	.345	.345	1.38
2019	.3625				

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 8.8 mill. elec., 1.3 mill. gas customers. Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: res'l, 53%; small comm'l & ind'l, 17%; large comm'l & ind'l, 15%; other, 15%. Generating sources: nuclear, 69%; other, 12%; purch., 19%. Fuel costs: 42% of revs. '17 depr. rates: 2.8%-7.0% elec., 2.1% gas. Has 34,600 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon's business mix continues to change. Before the company acquired Constellation Energy in 2012, more than 70% of its income came from its nonregulated power-generating business. Today, more than half of Exelon's earnings comes from its regulated utilities. The Constellation acquisition, the purchase of Pepco Holdings in 2016, rate relief at the utilities (especially those that came with the Pepco deal), and difficult market conditions for the nonutility operations are responsible for this shift. The proportion of corporate profits from the regulated business is likely to continue rising into the early part of the next decade. Because the utility business is less risky than the nonutility operations, we have raised the stock's Safety rank from 3 to 2 (Above Average).

Earnings are likely to wind up much higher this year. The comparison is easy; in 2018, mark-to-market accounting charges and unrealized losses in the company's nuclear decommissioning trusts reduced the bottom line by $0.61 a share. Also, the utilities continue to benefit from rate relief. Effective April 1st, Atlantic City Electric received a $70.0 million increase, based on a 9.6% return on a 49.4% common-equity ratio. Pepco is asking the Maryland regulators for a $27.2 million hike, based on a 10.3% return on a 50.5% common-equity ratio. An order is expected by August.

Exelon's nuclear plants continue to face challenging market conditions. On the positive side, the company's three units in New Jersey have qualified for subsidies that will enable the plants to avoid closing. But the Three Mile Island plant in Pennsylvania will be shut by the end of September after the state did not enact subsidies. Also, the Dresden, Byron, and Braidwood facilities in Illinois are in danger of being closed prematurely. Exelon's has a cost-cutting program to address the effects of pressure on margins.

The dividend yield of this timely equity is slightly below average for a utility. Like many utility issues, the recent quotation is well within our 2022-2024 Target Price Range. Thus, total return potential over that time frame is unimpressive, despite respectable dividend growth prospects.

Paul E. Debbas, CFA *May 17, 2019*

(A) Dil. egs. Excl. nonrec. gain (losses): '03, ($1.06); '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢); '17, $1.19. '16 & '18 EPS don't sum due to rounding. Next egs. report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '18: $15.40/sh. (D) In mill. (E) Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earned on avg. com. eq., '18: 6.6%. Reg. Climate: PA, NJ Avg.; IL, MD, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	20
Earnings Predictability	55

FORTIS INC. TSE-FTS.TO A

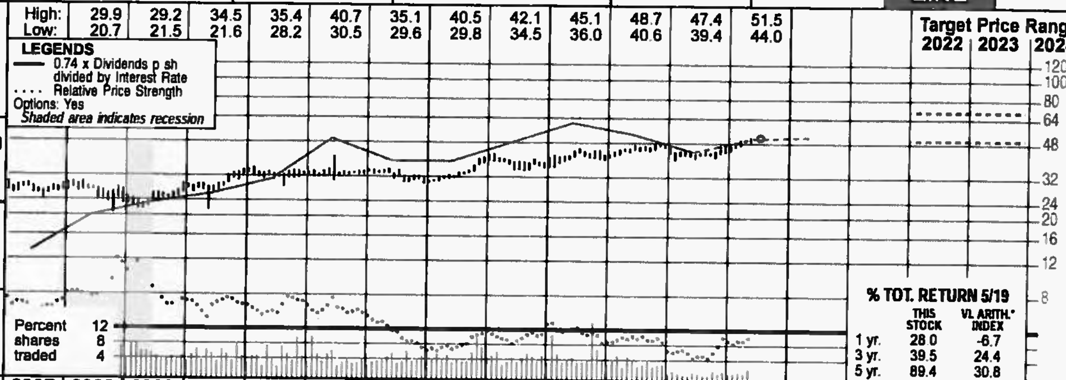
RECENT PRICE 51.37 | P/E RATIO 19.0 (Trailing: 20.1 Median: 19.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 1 Raised 6/14/19
SAFETY 2 Raised 7/17/15
TECHNICAL 3 Lowered 5/24/19
BETA .65 (1.00 = Market)

High:	29.9	29.2	34.5	35.4	40.7	35.1	40.5	42.1	45.1	48.7	47.4	51.5
Low:	20.7	21.5	21.6	28.2	30.5	29.6	29.8	34.5	36.0	40.6	39.4	44.0

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

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+35%)	11%
Low	50	(-5%)	4%

Insider Decisions

	A	S	O	N	D	J	F	M	A
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

	3Q2018	4Q2018	1Q2019
to Buy	103	123	120
to Sell	122	109	116
Hld's(000)	216243	226055	224810

% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.0	-6.7
3 yr.	39.5	24.4
5 yr.	89.4	30.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
12.13	11.99	13.86	14.14	17.48	23.07	21.24	21.01	19.84	19.07	18.99	19.57	23.89	17.03	19.71	19.58	**20.00**	**20.45**	Revenues per sh	**22.00**
1.92	2.23	2.73	3.05	2.96	3.51	3.66	3.99	3.90	4.10	4.10	3.62	5.21	3.91	5.43	5.40	**5.70**	**5.95**	"Cash Flow" per sh	**6.75**
1.03	1.01	1.19	1.36	1.29	1.52	1.51	1.62	1.74	1.65	1.63	1.38	2.11	1.89	2.66	2.52	**2.70**	**2.85**	Earnings per sh B	**3.25**
.52	.54	.59	.67	.82	1.00	1.04	1.12	1.17	1.21	1.25	1.30	1.43	1.55	1.65	1.75	**1.85**	**1.96**	Div'd Decl'd per sh C ■	**2.35**
2.99	2.92	4.93	4.80	5.16	5.34	5.79	5.89	5.91	5.68	5.32	6.00	7.97	5.13	7.18	7.51	**8.50**	**7.90**	Cap'l Spending per sh	**7.75**
8.84	10.47	11.76	12.26	16.72	18.00	18.57	18.95	20.53	20.84	22.39	24.90	28.63	32.32	31.77	34.80	**36.45**	**38.25**	Book Value per sh D	**44.00**
69.52	95.53	103.20	104.09	155.52	169.19	171.26	174.39	188.83	191.57	213.17	276.00	281.56	401.49	421.10	428.50	**435.00**	**440.00**	Common Shs Outst'g E	**455.00**
13.6	15.3	17.2	17.7	21.1	17.5	16.4	18.2	18.8	20.1	20.0	24.3	18.0	21.6	16.8	17.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**18.0**
.78	.81	.92	.96	1.12	1.05	1.09	1.16	1.18	1.28	1.12	1.28	.91	1.13	.84	.92	*estimates*		Relative P/E Ratio	**1.00**
3.7%	3.5%	2.9%	2.8%	3.0%	3.8%	4.2%	3.8%	3.6%	3.6%	3.8%	3.9%	3.8%	3.8%	3.7%	4.1%			Avg Ann'l Div'd Yield	**4.0%**

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
3637.0	3664.0	3747.0	3654.0	4047.0	5401.0	6727.0	6838.0	8301.0	8390.0	**8700**	**9000**	Revenues ($mill)	**10000**
280.0	313.0	347.0	362.0	390.0	374.0	672.0	660.0	1174.0	1136.0	**1325**	**1405**	Net Profit ($mill)	**1650**
14.4%	17.2%	18.3%	14.1%	7.4%	14.6%	21.3%	16.9%	25.8%	13.4%	**13.5%**	**13.5%**	Income Tax Rate	**13.5%**
6.4%	4.2%	5.5%	5.0%	5.9%	7.2%	7.4%	10.0%	9.5%	8.4%	**8.0%**	**7.0%**	AFUDC % to Net Profit	**7.0%**
61.3%	60.5%	57.5%	55.1%	53.5%	54.8%	53.3%	59.3%	58.4%	58.8%	**58.0%**	**56.5%**	Long-Term Debt Ratio	**54.0%**
34.8%	33.5%	36.9%	35.1%	37.0%	35.7%	38.1%	36.2%	37.1%	37.2%	**38.0%**	**40.0%**	Common Equity Ratio	**42.5%**
9136.0	9868.0	10513	11358	12892	19235	21151	35874	36108	40082	**41725**	**42300**	Total Capital ($mill)	**47200**
8246.0	8762.0	9281.0	10249	12267	17816	19595	29337	29668	32654	**35050**	**37150**	Net Plant ($mill)	**42600**
5.0%	5.0%	5.0%	4.8%	4.6%	3.4%	4.5%	2.8%	4.5%	4.1%	**4.5%**	**4.5%**	Return on Total Cap'l	**4.5%**
7.9%	8.0%	7.8%	7.1%	6.5%	4.3%	6.8%	4.5%	7.8%	6.9%	**7.5%**	**7.5%**	Return on Shr. Equity	**7.5%**
8.2%	8.6%	8.2%	7.9%	7.0%	4.5%	7.4%	4.5%	8.3%	7.2%	**7.5%**	**7.5%**	Return on Com Equity F	**7.5%**
4.1%	2.8%	4.3%	3.7%	3.2%	1.7%	4.5%	2.1%	5.2%	4.1%	**4.0%**	**4.0%**	Retained to Com Eq	**4.0%**
54%	71%	52%	60%	61%	68%	46%	59%	41%	46%	**42%**	**42%**	All Div'ds to Net Prof	**44%**

CAPITAL STRUCTURE as of 3/31/19
Total Debt $24592 mill. Due in 5 Yrs $6335 mill.
LT Debt $22950 mill. LT Interest $941 mill.
Incl. $339 mill. capitalized leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $8 mill.

Pension Assets-12/18 $2830 mill.
Oblig $3207 mill.
Pfd Stock $1623 mill. Pfd Div'd $66 mill.

Common Stock 430,900,000 shs.
as of 4/30/19
MARKET CAP: $22 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	173	231	208

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	4.5%	4.0%	*6.0%*
Earnings	5.5%	7.0%	*5.5%*
Dividends	7.0%	6.5%	*6.0%*
Book Value	7.5%	9.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1772	1485	1528	2053	6838
2017	2274	2015	1901	2111	8301
2018	2197	1947	2040	2206	8390
2019	2436	*2100*	*2100*	*2214*	*8850*
2020	*2500*	*2150*	*2150*	*2300*	*9100*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.57	.38	.45	.49	1.89
2017	.72	.62	.66	.66	2.66
2018	.69	.57	.65	.61	2.52
2019	.72	*.66*	*.68*	*.64*	*2.70*
2020	*.80*	*.70*	*.70*	*.65*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.34	.34	.34	.375	1.40
2016	.375	.375	.375	.40	1.53
2017	.40	.40	.40	.425	1.63
2018	.425	.425	.425	.45	1.73
2019	.45	.45			

BUSINESS: Fortis Inc.'s main focus is electricity, hydroelectric, and gas utility operations (both regulated and nonregulated) in the United States, Canada, and the Caribbean. Has 2 mill. electric, 1.3 mill. gas customers. Owns UNS Energy (Arizona), Central Hudson (New York), FortisBC Energy (British Columbia), FortisAlberta (Central Alberta), and Eastern Canada (Newfoundland). Sold commercial real estate and hotel property assets in 2015. Acquired ITC Holdings 10/16. Fuel costs: 30% of revenues. '18 reported deprec. rate: 2.5%. Has 8,800 employees. Chairman: Douglas J. Haughey. President & CEO: Barry V. Perry. Inc.: Canada. Address: Fortis Place, Suite 1100, 5 Springdale St., PO Box 8837, St. John's, NL, Canada, A1B 3T2. Tel.: 709-737-2800. Internet: www.fortisinc.com.

Fortis has completed an asset sale. In April, the company sold its 51% stake in a hydro project in British Columbia for about $1 billion. Fortis used the cash to reduce debt. It will record a gain of $450 million ($1.05 a share) after taxes when it reports second-quarter results, which we will *exclude* from our earnings presentation as a nonrecurring item. Fortis expects the sale to be neutral for its ongoing profits.

Tucson Electric Power filed a general rate case. The company is seeking a $115 million (7%) tariff hike, based on a 10.35% return on a 53% common-equity ratio. These are higher than the current figures of 9.75% and 50%, respectively. A ruling from the Arizona Corporation Commission is expected in 2020, in time for new rates to take effect on May 1st. This would be the utility's first base rate increase since the first quarter of 2017.

We look for respectable earnings growth in 2019 and 2020. Fortis' ITC subsidiary benefits from a forward-looking formula rate plan that enables it to earn a return on its capital spending and recover most kinds of expenses annually. Central Hudson G&E will receive the second phase of its three-year rate plan in mid-2019. And, assuming reasonable regulatory treatment, a partial year of rate relief at Tucson Electric will help Fortis' bottom line next year.

FortisBC filed an update to its multi-year rate plan. The current plan expires at the end of 2019. The utility wants to get approval of its capital plan through 2024. However, the filings will not address the cost of capital. FortisBC's allowed ROEs are 9.15% for electricity and 8.75% for gas, and the common-equity ratios are 40.0% for electricity and 38.5% for gas. These figures are well below those allowed for most utilities in the United States, so this illustrates a key difference between regulation in Canada and regulation in the United States.

This timely equity has a dividend yield that is moderately above the utility mean. Fortis has stated its goal of 6% annual dividend growth through 2023, which we project will be attained. This should produce total returns over the 3- to 5-year period that are modest, but still superior to those of most utility issues.

Paul E. Debbas, CFA *June 14, 2019*

(A) Also trades on NYSE under the symbol FTS. All data in Canadian $. (B) Diluted earnings. Excl. nonrec. gains (loss): '07, 3¢; '14, 2¢; '15, 48¢; '17, (35¢); '18, 7¢. 2Q '19, $1.05. Next earnings report due early Aug. (C) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (2% disc.). (D) Incl. intang. In '18: $38.70/sh (E) In millions. (F) Rate base: varies. Rates all'd on com. eq.: 8.3%-10.32%, earned on avg. com. eq., '18: 7.6%. Regulat. Climate: FERC, Above Average; AZ, Average; NY Below Average

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	70

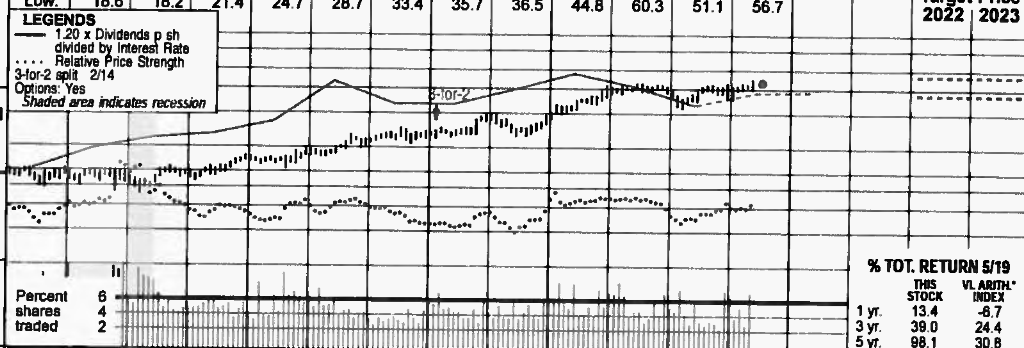
MGE ENERGY INC. NDQ-MGEE

RECENT PRICE 69.07 | P/E RATIO 25.1 (Trailing: 27.2 Median: 18.0) | RELATIVE P/E RATIO 1.52 | DIV'D YLD 2.0% | VALUE LINE

TIMELINESS 3 Raised 10/19/18
SAFETY 1 New 1/3/03
TECHNICAL 3 Raised 6/14/19
BETA .55 (1.00 = Market)

High:	24.3	25.5	29.1	31.9	37.4	40.5	48.0	48.0	66.9	68.7	68.9	72.2
Low:	18.6	18.2	21.4	24.7	28.7	33.4	35.7	36.5	44.8	60.3	51.1	56.7

LEGENDS
—— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 2/14
Options: Yes
Shaded area indicates recession



Target Price Range 2022 | 2023 | 2024

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+10%)	4%
Low	60	(-15%)	-1%

Insider Decisions

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

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	50	68	68
to Sell	59	62	62
Hld's(000)	14137	14238	14855

Percent shares traded 6 4 2

% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.4	-6.7
3 yr.	39.0	24.4
5 yr.	98.1	30.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
14.59	13.89	16.73	16.13	16.33	17.35	15.40	15.36	15.76	15.61	17.04	17.88	16.27	15.71	16.24	16.15	17.15	17.85	Revenues per sh	21.65
1.96	1.92	2.00	2.34	2.46	2.68	2.66	2.76	2.94	2.98	3.28	3.49	3.33	3.47	3.73	4.06	4.70	5.30	"Cash Flow" per sh	6.55
1.14	1.18	1.05	1.37	1.51	1.59	1.47	1.67	1.76	1.86	2.16	2.32	2.06	2.18	2.20	2.43	2.75	3.00	Earnings per sh A	3.80
.90	.91	.92	.93	.94	.96	.97	.99	1.01	1.04	1.07	1.11	1.16	1.21	1.26	1.32	1.38	1.45	Div'd Decl'd per sh B ■	1.65
3.02	3.13	2.80	2.94	4.14	3.08	2.35	1.76	1.88	2.84	3.43	2.67	2.08	2.41	3.12	6.12	6.45	6.85	Cap'l Spending per sh	8.05
9.56	11.06	11.21	11.93	12.99	13.92	14.47	15.14	15.89	16.71	17.81	19.02	19.92	20.89	22.45	23.56	24.55	26.00	Book Value per sh E	31.95
27.52	30.59	30.68	31.46	32.93	34.36	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	35.00	35.00	Common Shs Outst'g C	36.00
17.5	18.0	22.4	15.9	15.0	14.2	15.1	15.0	15.8	17.2	17.0	17.2	20.3	24.9	29.4	25.1	Bold figures are		Avg Ann'l P/E Ratio	18.0
1.00	.95	1.19	.86	.80	.85	1.01	.95	.99	1.09	.96	.91	1.02	1.31	1.48	1.35	Value Line		Relative P/E Ratio	1.00
4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	2.8%	2.8%	2.2%	2.0%	2.2%	estimates		Avg Ann'l Div'd Yield	2.4%
						533.8	532.6	546.4	541.3	590.9	619.9	564.0	544.7	563.1	559.8	600	625	Revenues ($mill)	780
						51.0	57.7	60.9	64.4	74.9	80.3	71.3	75.6	76.1	84.2	95.0	105	Net Profit ($mill)	135
						35.6%	36.9%	37.1%	37.7%	37.5%	37.5%	36.7%	36.0%	36.4%	24.6%	21.0%	21.0%	Income Tax Rate	21.0%
						--	--	--	--	--	--	--	--	2.2%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
						39.0%	38.9%	39.6%	38.2%	39.3%	37.5%	36.2%	34.6%	33.8%	37.7%	38.0%	37.5%	Long-Term Debt Ratio	36.0%
						61.0%	61.1%	60.4%	61.8%	60.7%	62.5%	63.8%	65.4%	66.2%	62.3%	62.0%	62.5%	Common Equity Ratio	64.0%
						822.7	859.4	911.9	937.9	1016.9	1054.7	1081.5	1106.9	1176.3	1310.0	1385	1460	Total Capital ($mill)	1800
						939.8	968.0	995.6	1073.5	1160.2	1208.1	1243.4	1282.1	1341.4	1509.4	1640	1800	Net Plant ($mill)	2250
						6.9%	7.6%	7.8%	7.9%	8.3%	8.5%	7.5%	7.7%	7.2%	7.2%	7.5%	8.0%	Return on Total Cap'l	8.5%
						10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	11.0%	11.5%	Return on Shr. Equity	11.5%
						10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	11.0%	11.5%	Return on Com Equity D	11.5%
						3.4%	4.4%	4.7%	4.9%	6.1%	6.4%	4.5%	4.7%	4.2%	4.7%	5.5%	6.0%	Retained to Com Eq	6.5%
						66%	60%	57%	56%	50%	48%	56%	55%	57%	54%	51%	48%	All Div'ds to Net Prof	44%

CAPITAL STRUCTURE as of 3/31/19
Total Debt $502.9 mill. Due in 5 Yrs $81.9 mill.
LT Debt $492.3 mill. LT Interest $22.0 mill.
(Total interest earned: 6.6x)

Leases, Uncapitalized Annual rentals $1.6 mill.
Pension Assets-12/18 $323.8 mill.
Obligation $360.3 mill.
Pfd Stock None

Common Stock 34,668,370 shs.
as of 4/30/19
MARKET CAP: $2.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	1.1	-2.6	1.6
Avg. Indust. Use (MWH)	2329	1966	1802
Avg. Indust. Revs. per KWH (¢)	7.55	8.23	7.70
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	783	783	783
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	645	666	582

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-.5%	--	5.0%
"Cash Flow"	4.0%	4.0%	9.5%
Earnings	4.5%	3.5%	9.0%
Dividends	3.0%	4.0%	4.5%
Book Value	5.5%	6.0%	6.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	147.5	121.6	136.7	138.9	544.7
2017	156.8	126.5	139.5	140.3	563.1
2018	157.6	124.3	137.8	140.1	559.8
2019	167.6	135	148	149.4	600
2020	172	140	155	158	625

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.49	.47	.80	.42	2.18
2017	.56	.45	.77	.42	2.20
2018	.58	.53	.85	.47	2.43
2019	.69	.60	.92	.54	2.75
2020	.74	.66	1.00	.60	3.00

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.2825	.2825	.2950	.2950	1.16
2016	.2950	.2950	.3075	.3075	1.21
2017	.3075	.3075	.3225	.3225	1.26
2018	.3225	.3225	.3375	.3375	1.32
2019	.3375				

BUSINESS: MGE Energy, Inc. is a holding company for Madison Gas and Electric. It provides electric service to about 153,000 customers in Dane County and gas service to 161,000 customers in seven counties in Wisconsin. Electric revenue breakdown, '18: residential, 35%; commercial, 52%; industrial, 4%; public authorities, 9%. Generating sources, '18: coal, 52%; purchased power, 23%; natural gas and other, 25%. Fuel costs: 19% of rev. '18 depr. rate: 3.7%. Has 706 employees. Off. and dir. own less than 1% of common; The Vanguard Group, Inc., 10.2%; BlackRock, Inc., 7.2% (3/19 proxy). Chairman, President & CEO: Jeffrey M. Keebler. Inc.: WI. Addr.: 133 South Blair St., Madison, WI 53788. Tel.: 608-252-7000. Web: www.mgeenergy.com.

Shares of MGE Energy have edged higher in price over the past three months. The company reported good performance for the March quarter. The top line advanced roughly 6%, on a year-over-year basis. Earnings per share increased nearly 19%, to $0.69. MGE benefited from growth in retail customers and greater gas retail sales due to higher customer demand resulting from colder temperatures compared with the year-ago period. Moreover, the company's Electric business benefited from its investment in the Saratoga wind farm, which came on line in February. This new 66-megawatt wind farm is fully operational and delivering sustainable, carbon-free energy.

Healthy results ought to continue going forward. We anticipate favorable comparisons in the coming quarters, and revenues and share earnings growth of 7% and 13%, respectively, for the current year. Performance should remain favorable from 2020 onward. The company's utility operations ought to further benefit from attractive demographics in their service territories. This includes healthy population growth and low unemployment in its operating areas. Investment in operations should also continue to pay off. The company's stake in the Forward Wind Energy Center should provide access to renewable energy for an additional 15 years. Elsewhere, its transmission investments will probably further benefit the bottom line. A push into solar power also appears promising.

This stock is neutrally ranked for year-ahead relative price performance. Looking further out, this equity offers limited appreciation potential for the pull to early next decade. Favorable operating prospects appear to be reflected in the recent quotation, as the shares presently trade at a price-to-earnings multiple that is significantly greater than their historical average. Moreover, the dividend yield is below average for a utility. In the plus column, MGE Energy earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Volatility is subdued, as well. A selloff some time down the road might offer conservative, income-seeking accounts a more-attractive entry point.

Michael Napoli, CFA *June 14, 2019*

(A) Diluted earnings. Excludes nonrecurring: '17, 62¢. Next earnings report due early August. (B) Dividends historically paid in mid-March, June, September and December. ■ Div'd. reinvestment plan available (C) In millions, adjusted for split (D) Rate allowed on common equity in '18: 9.8%, earned on common equity, '18: 10.3%. Regulatory Climate: Above Average. (E) Includes regulatory assets in 2018: $154.9 mill., $4.47 per share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	95

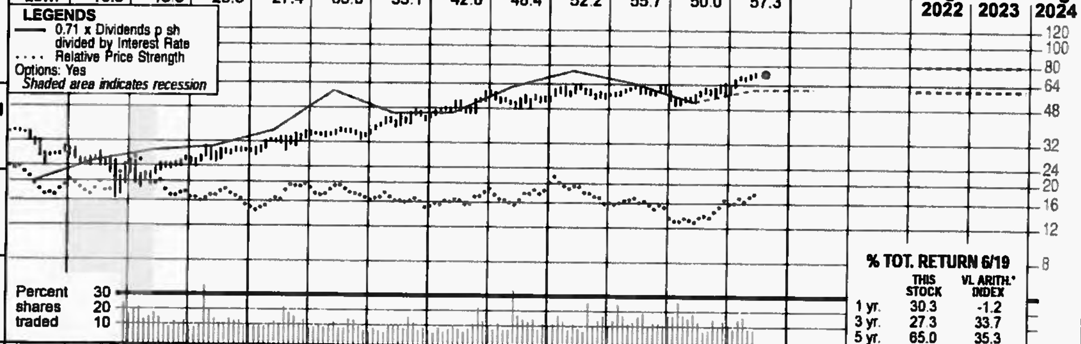
NORTHWESTERN NYSE-NWE

RECENT PRICE 72.85 | P/E RATIO 19.7 (Trailing: 19.9 Median: 16.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 1 Raised 6/7/19
SAFETY 2 Raised 7/27/18
TECHNICAL 1 Raised 7/5/19
BETA .60 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	29.7	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	74.5
Low:	16.5	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3

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



Target Price Range
2022 | 2023 | 2024

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+10%)	6%
Low	60	(-20%)	-1%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	4	12	0	0	0
to Sell	0	0	2	0	0	3	0	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	128	118	140
to Sell	111	143	126
Hld's(000)	49333	48945	48402

% TOT. RETURN 6/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.3	-1.2
3 yr.	27.3	33.7
5 yr.	65.0	35.3

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
--	29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	25.25	25.65	Revenues per sh	28.50
--	3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.40	7.30	"Cash Flow" per sh	8.25
--	d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.70	3.60	Earnings per sh A	4.00
--	--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	Div'd Decl'd per sh B ■ †	2.70
--	2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.65	6.55	Cap'l Spending per sh	6.00
--	19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	39.90	41.00	Book Value per sh C	44.50
--	35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.50	50.65	Common Shs Outst'g D	51.10
--	--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	Bold figures are	Value Line	Avg Ann'l P/E Ratio	18.0
--	--	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	estimates		Relative P/E Ratio	1.00
--	--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%			Avg Ann'l Div'd Yield	3.8%

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1141.9	1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1275	1300	Revenues ($mill)	1450
73.4	77.4	92.6	83.7	94.0	120.7	138.4	164.2	162.7	171.1	190	185	Net Profit ($mill)	210
17.2%	25.0%	9.8%	9.6%	13.2%	--	13.7%	--	7.6%	7.6%	2.5%	5.0%	Income Tax Rate	10.0%
4.4%	14.2%	3.3%	9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.0%	4.0%	AFUDC % to Net Profit	3.0%
56.4%	57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	51.5%	50.5%	Long-Term Debt Ratio	48.0%
43.6%	42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	48.5%	49.5%	Common Equity Ratio	52.0%
1803.9	1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4135	4195	Total Capital ($mill)	4400
1964.1	2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4670	4820	Net Plant ($mill)	5125
6.0%	5.9%	7.0%	5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.5%	5.5%	Return on Total Cap'l	5.5%
9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	9.5%	9.0%	Return on Shr. Equity	9.0%
9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	9.5%	9.0%	Return on Com Equity E	9.0%
3.2%	3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.5%	3.0%	Retained to Com Eq	3.0%
66%	63%	56%	65%	61%	54%	65%	58%	62%	64%	62%	66%	All Div'ds to Net Prof	66%

CAPITAL STRUCTURE as of 3/31/19
Total Debt $2102.1 mill. Due in 5 Yrs $321.5 mill.
LT Debt $2099.8 mill. LT Interest $82.9 mill.
Incl. $19.3 mill. capitalized leases.
(LT interest earned: 3.1x)

Pension Assets-12/18 $525.3 mill.
Oblig $649.6 mill.
Pfd Stock None

Common Stock 50,439,930 shs.
as of 4/19/19

MARKET CAP: $3.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.7	+3.8	+2.9
Avg. Indust. Use (MWH)	29784	30987	34573
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2138	2133	2173
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.3	+1.2
Fixed Charge Cov. (%)	253	275	275

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-2.5%	-3.0%	2.0%
"Cash Flow"	5.5%	5.0%	3.0%
Earnings	8.5%	7.0%	3.0%
Dividends	5.0%	7.0%	4.5%
Book Value	5.5%	8.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	332.5	293.1	301.0	330.6	1257.2
2017	367.3	283.9	309.9	344.6	1305.7
2018	341.5	261.8	279.9	314.9	1198.1
2019	384.2	270.8	295	325	1275
2020	365	285	310	340	1300

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.82	.73	.92	.92	3.39
2017	1.17	.44	.75	.98	3.34
2018	1.18	.61	.56	1.06	3.40
2019	1.44	.55	.71	1.00	3.70
2020	1.25	.55	.75	1.05	3.60

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.48	.48	.48	.48	1.92
2016	.50	.50	.50	.50	2.00
2017	.525	.525	.525	.525	2.10
2018	.55	.55	.55	.55	2.20
2019	.575	.575			

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 438,000 electric customers in Montana and South Dakota and 289,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 39%; commercial, 46%; industrial, 5%; other, 10%. Generating sources: hydro, 35%; coal, 29%; wind, 6%; other, 4%; purchased, 26%. Fuel costs: 24% of revenues. '18 reported deprec. rate: 3.0%. Has 1,500 employees. Chairman: Stephen P. Adik. President & CEO: Robert C. Rowe. Inc.: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern has reached a partial settlement of its electric rate case in Montana. The utility had sought an increase of $30.7 million (6.1%), based on a 10.65% return on a 49.4% common-equity ratio. The settlement calls for a hike of $6.5 million (1.3%), based on a 9.65% return on a 49.4% common-equity ratio, and a $9.3 million reduction in annual depreciation expense. However, the settlement does not address rate design matters (such as rates among customer classes and NorthWestern's request to add a demand charge to the bills of customers with rooftop solar generation, so that other customers aren't subsidizing solar users). An order is expected by October. Note that the utility has been collecting an interim rate increase since April 1st, and will continue to do so until new tariffs take effect.

We have raised our 2019 earnings estimate by $0.20 a share. First-quarter profits benefited from favorable weather conditions. This boosted the bottom line by $0.21 a share. Even without the boost from weather, earnings would likely wind up higher for the year anyway, thanks to customer growth and a partial year of rate relief. Note that, despite the partial regulatory settlement, management is not providing earnings guidance while the aforementioned rate case is pending.

Earnings are likely to decline in 2020. We assume normal weather patterns in our estimate, so that would hurt first-period results, despite rate relief. Even so, we expect another dividend hike in the March quarter, as usual for the company.

The utility expects to file an electricity supply resource plan in Montana soon. NorthWestern has been relying on purchased power to meet its peak demand needs, but regional capacity shortfalls might occur as early as 2021. The utility expects to seek competitive bids for peaking capacity that will be available by 2022.

The price of this timely stock is up 23% this year. This is even better than most utility equities have fared. There doesn't appear to be any specific thing that has triggered this outperformance. Perhaps there is some takeover speculation. This issue's dividend yield and 3- to 5-year total return potential are close to the utility averages.

Paul E. Debbas, CFA *July 26, 2019*

(A) Diluted EPS. Excl. gain (loss) on discont. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15 27¢; '18, 52¢. '18 EPS don't sum due to rounding. Next earnings report due late Oct.
(B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail.
(C) Incl. def'd charges. In '18: $15.80/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%, in '17 (gas): 9.55%; in SD in 15: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '18: 9.2%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	85

P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 58.84 | P/E RATIO 16.6 (Trailing: 19.4; Median: 13.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Lowered 5/3/19
SAFETY 1 Raised 11/23/12
TECHNICAL 2 Raised 4/19/19
BETA .65 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	52.3	34.1	34.9	35.5	34.1	37.0	43.8	44.4	47.4	53.3	56.7	60.4
Low:	22.1	23.7	29.0	28.0	28.9	29.7	31.3	36.8	37.8	41.7	46.2	50.0

Target Price Range 2022 | 2023 | 2024

2022-24 PROJECTIONS

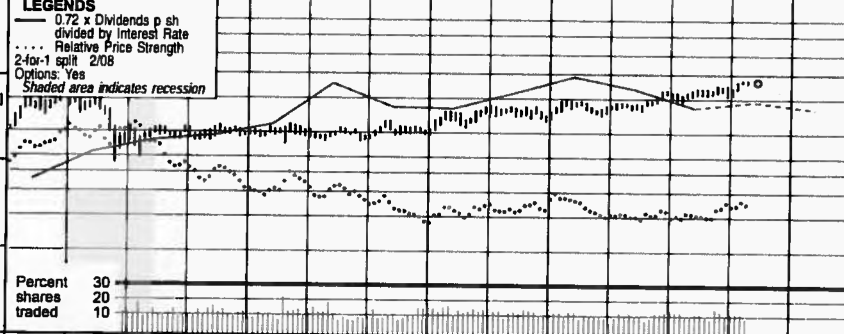
	Price	Gain	Ann'l Total Return
High	65	(+10%)	6%
Low	50	(-15%)	Nil

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	1	1	2	7	7
to Sell	1	1	0	1	2	2	1	1	2

Institutional Decisions

	2Q2018	3Q2018	4Q2018
to Buy	308	319	344
to Sell	354	351	360
Hld's(000)	347205	347951	346789



% TOT. RETURN 4/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.3	5.6
3 yr.	44.1	37.6
5 yr.	75.3	44.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
23.54	23.09	24.74	24.07	25.28	27.94	24.57	23.31	22.42	19.33	19.71	21.52	20.61	18.22	18.14	19.24	19.40	20.40	Revenues per sh	23.00
2.92	3.02	3.42	3.91	4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.82	6.15	5.07	5.30	5.44	6.45	6.50	"Cash Flow" per sh	7.75
1.88	1.52	1.79	1.85	2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.99	3.30	2.83	2.82	2.76	3.55	3.40	Earnings per sh A	4.00
1.08	1.10	1.12	1.14	1.17	1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.56	1.64	1.72	1.80	1.88	1.96	Div'd Decl'd per sh B ■ †	2.30
2.86	2.64	2.04	2.01	2.65	3.50	3.55	4.27	4.12	5.09	5.56	5.58	7.65	8.32	8.30	7.76	5.95	5.95	Cap'l Spending per sh	6.00
11.71	12.05	11.99	13.35	14.35	15.36	17.37	19.04	20.30	21.31	22.95	24.09	25.86	26.01	27.42	28.53	30.15	31.60	Book Value per sh C	36.50
472.27	476.20	502.33	505.29	508.52	506.02	505.99	505.97	505.95	505.89	505.86	505.84	505.28	504.87	505.00	504.00	505.00	505.00	Common Shs Outst'g D	505.00
10.6	14.3	16.5	17.8	16.5	13.6	10.0	10.4	10.4	12.8	13.5	12.6	12.4	15.3	16.3	18.7	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.5
.60	.76	.88	.96	.88	.82	.67	.66	.65	.81	.76	.66	.62	.80	.82	1.01	estimates		Relative P/E Ratio	.80
5.4%	5.1%	3.8%	3.5%	2.7%	3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	3.9%	3.8%	3.8%	3.7%	3.5%			Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 3/31/19
Total Debt $15267 mill. **Due in 5 Yrs** $7575 mill.
LT Debt $13216 mill. **LT Interest** $509 mill.
(LT interest earned: 4.1x)

Leases, Uncapitalized Annual rentals $41 mill.

Pension Assets-12/18 $5120 mill. **Oblig** $5921 mill.

Pfd Stock None

Common Stock 505,430,473 shs. **as of 4/16/19**
MARKET CAP: $30 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
12431	11793	11343	9781.0	9968.0	10886	10415	9198.0	9161.0	9696.0	9800	10300	Revenues ($mill)	11600
1567.0	1557.0	1577.0	1239.0	1243.0	1518.0	1679.0	1436.0	1431.0	1399.0	1800	1720	Net Profit ($mill)	2010
42.3%	40.5%	40.4%	36.2%	39.5%	38.2%	37.4%	31.7%	37.3%	22.3%	17.5%	17.5%	Income Tax Rate	17.5%
3.8%	5.5%	2.7%	4.8%	4.6%	4.5%	5.5%	8.4%	10.6%	9.8%	8.0%	8.0%	AFUDC % to Net Profit	7.0%
46.3%	44.8%	42.1%	38.3%	40.4%	40.4%	40.3%	45.3%	46.6%	47.8%	48.0%	48.5%	Long-Term Debt Ratio	50.5%
53.2%	55.2%	57.9%	61.7%	59.6%	59.6%	59.7%	54.7%	53.4%	52.2%	52.0%	51.5%	Common Equity Ratio	49.5%
16513	17452	17731	17467	19470	20446	21900	24025	25915	27545	29300	31025	Total Capital ($mill)	37000
15440	16390	17849	19736	21645	23589	26539	29286	31797	34363	35950	37425	Net Plant ($mill)	41200
11.0%	10.4%	10.2%	8.1%	7.5%	8.4%	8.6%	6.8%	6.4%	6.0%	7.0%	6.5%	Return on Total Cap'l	6.5%
17.7%	16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	12.0%	11.0%	Return on Shr. Equity	11.0%
17.8%	16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	12.0%	11.0%	Return on Com Equity E	11.0%
10.1%	9.0%	8.6%	4.8%	4.4%	6.3%	6.8%	4.6%	4.1%	3.4%	5.5%	4.5%	Retained to Com Eq	4.5%
43%	45%	44%	58%	59%	49%	47%	58%	61%	65%	53%	58%	All Div'ds to Net Prof	58%

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.3	-2.0	+2.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	9567	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	522	503	413

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-3.0%	-2.0%	3.5%
"Cash Flow"	2.0%	.5%	6.5%
Earnings	1.5%	1.0%	6.0%
Dividends	3.5%	4.0%	5.0%
Book Value	6.5%	5.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2616	1905	2587	2090	9198
2017	2647	2155	2263	2096	9161
2018	2818	2016	2394	2468	9696
2019	2980	2100	2400	2320	9800
2020	3150	2200	2500	2450	10300

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.93	.37	.94	.59	2.83
2017	.94	.69	.78	.42	2.82
2018	1.10	.53	.81	.32	2.76
2019	1.38	.66	.90	.61	3.55
2020	1.10	.70	.95	.65	3.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.39	.39	.39	.39	1.56
2016	.41	.41	.41	.41	1.64
2017	.43	.43	.43	.43	1.72
2018	.45	.45	.45	.45	1.80
2019	.47				

BUSINESS: Public Service Enterprise Group Incorporated is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.3 million electric and 1.8 million gas customers in New Jersey, and PSEG Power LLC, a nonregulated power generator with nuclear, gas, and coal-fired plants in the Northeast. PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out data on electric and gas operating statistics. Fuel costs: 33% of revenues. '18 reported depreciation rates (utility): 1.6%-2.5%. Has 13,100 employees. Chairman, President & Chief Executive Officer: Dr. Ralph Izzo. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Telephone: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group's earnings will probably wind up significantly higher in 2019. The year-to-year comparison is skewed by mark-to-market accounting items and gains or losses on the nuclear decommissioning trusts that PSEG books every quarter. These items hurt share profits by $0.36 in 2018, but helped by $0.30 in the first quarter this year. (We *include* these gains or charges in our earnings presentation because they are an ongoing part of the company's results.) However, this is not the only reason for the expected bottom-line improvement. The utility subsidiary, Public Service Electric and Gas, is benefiting from a full year's effect of a $212 million electric and gas rate increase (before passing through to customers $225 million of federal tax reductions resulting from the new tax law) that took effect in November of 2018.

Capital spending plans are large. This should enable PSE&G's rate base to rise at an average annual pace of 7%-9% over the next five years. (Two proposed capital spending programs, totaling $6 billion, are awaiting the approval of the state regulators.) Transmission is a key area of investment, as well. Much of this spending will be recovered through regulatory mechanisms, instead of a general rate case. This will reduce the effects of regulatory lag and increase the utility's earning power.

The news is mixed at PSEG Power, the main nonutility subsidiary. Margins on electricity sales have been declining in recent years, and this happened again in the first quarter. In fact, the company's three nuclear units in New Jersey were at risk of being shut down due to difficult market conditions. However, the state granted subsidies for the plants, which will enable them to remain open. PSEG Power is also benefiting from two new gas-fired plants that replaced old, less-efficient capacity. Another such plant is expected to be completed in mid-2019.

The board of directors raised the dividend in the first quarter. The increase was two cents a share (4.4%) quarterly.

This high-quality stock has a dividend yield that is close to the utility mean. With the recent quotation well within our 2022-2024 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *May 17, 2019*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '05, (3¢); '06, (35¢); '08, (96¢); '09, 6¢; 11, (34¢); '12, 7¢; '16, (30¢), '17, 28¢ (net); '18, 8¢, gains (loss) from disc. ops.: '05, (33¢); '06, 12¢; '07, 3¢; '08, 40¢; '11, 13¢. '17 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinv plan avail. (C) Incl. intang. In '18: $7.06/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '18: 9.6%: earned on avg. com. eq., '18: 9.9% Regulatory Climate: Avg.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	70

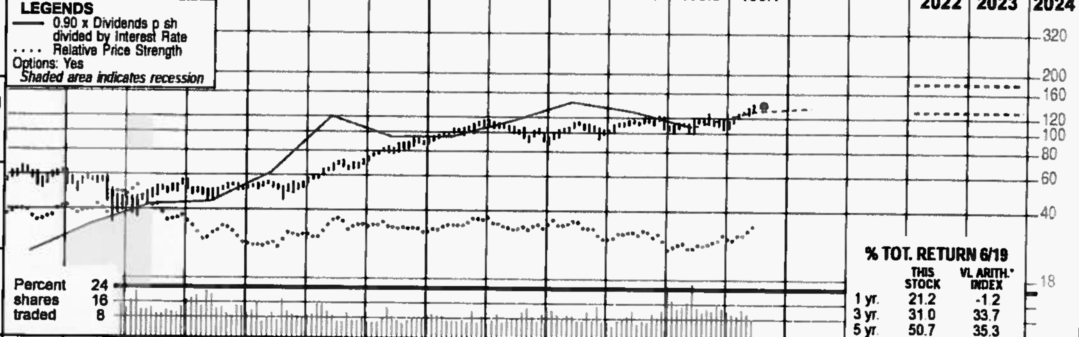
SEMPRA ENERGY NYSE-SRE

RECENT PRICE **139.26** | P/E RATIO **23.6** (Trailing: 24.7 Median: 19.0) | RELATIVE P/E RATIO **1.38** | DIV'D YLD **2.9%** | VALUE LINE

TIMELINESS **3** Lowered 6/21/19
SAFETY **2** Raised 7/29/16
TECHNICAL **3** Raised 6/28/19
BETA .75 (1.00 = Market)

High:	63.0	57.2	57.2	56.0	72.9	93.0	116.3	116.2	114.7	123.0	127.2	141.9
Low:	34.3	36.4	43.9	44.8	54.7	70.6	86.7	89.4	86.7	99.7	100.5	106.1

Target Price Range
2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	180	(+30%)	10%
Low	130	(-5%)	2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	2	1	7	7	0	1	3
to Sell	0	0	3	1	2	1	0	1	3

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	314	344	344
to Sell	264	277	294
Hld's(000)	257869	263178	266999

Percent shares traded 24 16 8

% TOT. RETURN 6/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.2	-1.2
3 yr.	31.0	33.7
5 yr.	50.7	35.3

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
34.81	40.18	45.64	44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	44.59	42.69	*40.00*	*41.65*	Revenues per sh	*45.25*
5.56	6.58	5.96	6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	10.57	11.07	*11.20*	*12.40*	"Cash Flow" per sh	*15.00*
3.01	3.93	3.52	4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	4.63	5.48	*5.90*	*6.95*	Earnings per sh A	*9.00*
1.00	1.00	1.16	1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.29	3.58	*3.87*	*4.20*	Div'd Decl'd per sh B ■	*5.25*
4.63	4.62	5.46	7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	15.71	13.82	*16.90*	*13.40*	Cap'l Spending per sh	*10.25*
17.17	20.78	23.95	28.66	31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	50.41	54.35	*60.00*	*64.70*	Book Value per sh C	*76.50*
226.60	234.18	257.19	262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	251.36	273.77	*290.00*	*300.00*	Common Shs Outst'g D	*320.00*
9.0	8.6	11.8	11.5	14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	24.3	20.4	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.51	.45	.63	.62	.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	*Value Line*		Relative P/E Ratio	*.95*
3.7%	2.9%	2.8%	2.5%	2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	2.9%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 3/31/19
Total Debt $24413 mill. **Due in 5 Yrs** $10589 mill.
LT Debt $19736 mill. **LT Interest** $780 mill.
Incl. $1275 mill. capitalized leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $91 mill.
Pension Assets-12/18 $2160 mill. **Oblig** $3356 mill.
Pfd Stock $2278 mill. **Pfd Div'd** $105 mill.
17,250,000 shs. 6% mandatorily convertible preferred stock; 811,073 shs. 6% cum., $25 par.
Common Stock 274,388,245 shs. **as of 5/2/19**
MARKET CAP: $38 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
8106.0	9003.0	10036	9647.0	10557	11035	10231	10183	11207	11687	*11600*	*12500*	Revenues ($mill)	*14500*
1193.0	1008.0	1088.0	1079.0	1060.0	1162.0	1314.0	1065.0	1169.0	1607.0	*1905*	*2290*	Net Profit ($mill)	*3010*
30.5%	26.5%	25.3%	18.2%	26.5%	19.7%	19.2%	14.4%	24.5%	20.1%	*21.0%*	*21.0%*	Income Tax Rate	*23.0%*
10.6%	11.3%	15.2%	17.2%	11.2%	14.4%	15.3%	22.2%	21.9%	12.6%	*11.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
44.8%	49.4%	50.4%	52.8%	50.5%	51.7%	52.6%	52.7%	56.4%	55.7%	*54.0%*	*53.0%*	Long-Term Debt Ratio	*54.0%*
54.1%	49.6%	49.2%	46.7%	49.4%	48.2%	47.3%	47.3%	43.5%	38.4%	*40.5%*	*42.0%*	Common Equity Ratio	*46.0%*
16646	18186	20015	22002	22281	23513	24963	27400	29135	38769	*42750*	*46125*	Total Capital ($mill)	*53400*
18281	19876	23572	25191	25460	25902	28039	32931	36503	36796	*37750*	*40100*	Net Plant ($mill)	*44100*
8.3%	6.8%	6.7%	6.1%	6.0%	6.1%	6.4%	5.0%	5.1%	5.1%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
13.0%	10.9%	10.9%	10.4%	9.6%	10.2%	11.1%	8.2%	9.2%	9.4%	*9.0%*	*10.0%*	Return on Shr. Equity	*12.0%*
13.1%	11.1%	11.0%	10.4%	9.6%	10.3%	11.1%	8.2%	9.2%	10.0%	*9.5%*	*10.5%*	Return on Com Equity E	*12.0%*
9.3%	7.0%	6.5%	5.1%	4.1%	5.0%	5.8%	2.9%	3.3%	4.1%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
29%	37%	41%	52%	58%	52%	48%	65%	65%	62%	*68%*	*63%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-3.8	-.2	-3.2
Avg. Indust. Use (MWH)	4785	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.6	+.8	+.9
Fixed Charge Cov. (%)	237	264	186

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-.5%	.5%	*1.0%*
"Cash Flow"	4.0%	3.5%	*6.5%*
Earnings	1.0%	2.0%	*11.0%*
Dividends	10.0%	7.5%	*8.0%*
Book Value	5.5%	4.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2622	2156	2535	2870	10183
2017	3031	2533	2679	2964	11207
2018	2962	2564	2940	3221	11687
2019	2898	*2600*	*2900*	*3202*	*11600*
2020	*3150*	*2750*	*3150*	*3450*	*12500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.61	.06	1.02	1.52	4.24
2017	1.75	1.20	.22	1.46	4.63
2018	1.43	1.27	1.23	1.55	5.48
2019	1.78	*1.25*	*1.27*	*1.60*	*5.90*
2020	*2.00*	*1.60*	*1.50*	*1.85*	*6.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.66	.70	.70	.70	2.76
2016	.70	.755	.755	.755	2.97
2017	.755	.8225	.8225	.8225	3.22
2018	.8225	.895	.895	.895	3.51
2019	.895	.9675	.9675		

BUSINESS: Sempra Energy is a holding co. for San Diego Gas & Electric Company, which sells electricity & gas mainly in San Diego County, & Southern California Gas Company, which distributes gas to most of Southern California. Owns 80% of Oncor (acq'd 3/18), which distributes electricity in Texas. Customers: 4.9 mill. electric, 6.6 mill. gas. Electric rev. breakdown: residential, 41%; commercial, 42%; industrial, 10%; other, 7%. Purchases most of its power; the rest is gas. Has nonutility subsidiaries. Sold commodities business in '10. Power costs: 34% of revs. '18 reported deprec. rates: 2.4%-6.4%. Has 20,000 employees. Chairman: Debra L. Reed. CEO: Jeffrey W. Martin. Inc.: CA. Address: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy completed a major acquisition in May. Oncor, the company's transmission and distribution subsidiary in Texas, paid $1.275 billion for InfraREIT, a transmission company. Sempra expects the purchase to contribute roughly $0.25 a share to earnings this year.

The company is also selling assets. Since late 2018, Sempra has completed the sale of its gas storage assets, wind assets, and solar assets for cash and other compensation of about $2.5 billion, some of which was used for the InfraREIT acquisition. The company intends to sell its utilities in South America, and is now reporting these as discontinued operations. Management expects to complete the sale of these businesses by yearend.

The domestic utilities have general rate cases and cost-of-capital applications pending. Southern California Gas and San Diego Gas and Electric are requesting increases of $481 million and $221 million, respectively. An order, which will be retroactive to the start of 2019, is expected soon. SDG&E is asking the California commission for an allowed return on equity of 14.3% (including a 3.4% "adder" for potential wildfire-related risks) and asking the Federal Energy Regulatory Commission for an ROE of 11.2%. Southern California Gas asked the California regulators for a 10.7% ROE. A ruling is expected by yearend.

Earnings are likely to rise at a healthy pace in 2019 and 2020. Rate increases, income from utilities that were acquired, growth from the businesses in Mexico, and the beginning of operations at a liquefied natural gas facility should offset the loss of income from the assets that were sold or discontinued. Our share-earnings estimates are within Sempra's targeted ranges of $5.70-$6.30 and $6.70-$7.50 for 2019 and 2020, respectively.

This stock has been one of the top performers among utilities so far in 2019. The share price has risen 29%. The market has applauded Sempra's asset purchases and sales, which have narrowed its operational and geographic scope. The dividend yield is modest for a utility. Total return potential to 2022-2024 is low, but still superior to that of most issues in this industry.

Paul E. Debbas, CFA *July 26, 2019*

(A) Dil. EPS. Excl. nonrec. gains (losses): '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢); '15, 14¢; '16, $1.23; '17, (17¢); '18, ($2.06); gain (losses) from disc. ops : '06 $1.21; '07, (10¢); '19, (19¢). '16 EPS don't sum due to chg. in shs. Next egs. report due early Aug. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '18: $15.47/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '13: 10.3%; SoCalGas in '13: 10.1%; earn. on avg. com. eq., '18: 10.5%. Regulat. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	75

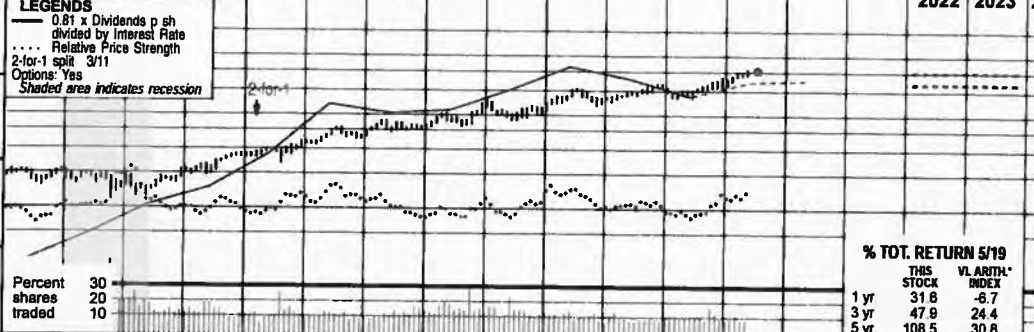
WEC ENERGY GROUP NYSE-WEC

RECENT PRICE	P/E RATIO	(Trailing: 23.6 / Median: 17.0)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
81.29	23.1	Trailing: 23.6; Median: 17.0	1.40	3.0%	

TIMELINESS	3 Lowered 6/7/19
SAFETY	1 Raised 3/23/12
TECHNICAL	3 Raised 6/14/19
BETA	.50 (1.00 = Market)

High:	24.8	25.3	30.5	35.4	41.5	45.0	55.4	58.0	66.1	70.1	75.5	83.0
Low:	17.4	18.2	23.4	27.0	33.6	37.0	40.2	44.9	50.4	56.1	58.5	67.2

Target Price Range
2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(Nil)	3%
Low	70	(-15%)	Nil

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	2	1	23	4	1	0
to Sell	2	0	0	2	1	0	5	1	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	310	371	352
to Sell	348	321	367
Hld's(000)	230392	236513	236446

% TOT. RETURN 5/19

	THIS STOCK	VL ARITH.* INDEX
1 yr	31.6	-6.7
3 yr	47.9	24.4
5 yr	108.5	30.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	18.54	20.00	22.16	18.77	23.68	24.24	24.34	**25.05**	**26.00**	Revenues per sh	**29.50**
2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	4.01	4.33	4.47	3.87	5.39	5.69	6.04	**6.45**	**6.90**	"Cash Flow" per sh	**8.50**
1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.18	2.35	2.51	2.59	2.34	2.96	3.14	3.34	**3.52**	**3.70**	Earnings per sh A	**4.50**
.40	.42	.44	.46	.50	.54	.68	.80	1.04	1.20	1.45	1.56	1.74	1.98	2.08	2.21	**2.36**	**2.50**	Div'd Decl'd per sh B ■	**3.00**
2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	3.09	3.04	3.26	4.01	4.51	6.21	6.71	**9.45**	**10.10**	Cap'l Spending per sh	**7.75**
9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	18.05	18.73	19.60	27.42	28.29	29.98	31.02	**32.05**	**33.10**	Book Value per sh C	**36.75**
236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	229.04	225.96	225.52	315.68	315.62	315.57	315.52	**315.50**	**315.50**	Common Shs Outst'g D	**315.50**
12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	15.8	16.5	17.7	21.3	19.9	20.0	19.6	Bold figures are		Avg Ann'l P/E Ratio	**16.5**
.71	.92	.77	.86	.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	1.01	1.06	Value Line		Relative P/E Ratio	**.90**
2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	3.4%	3.5%	3.4%	3.3%	3.4%	estimates		Avg Ann'l Div'd Yield	**4.0%**

CAPITAL STRUCTURE as of 3/31/19
Total Debt $11838 mill. **Due in 5 Yrs** $3987.9 mill.
LT Debt $10327 mill. **LT Interest** $499.7 mill.
Incl. $18.4 mill. capitalized leases.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $8.7 mill.
Pension Assets-12/18 $2690.8 mill. Oblig $2927.2 mill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable. $101;
44,498 shs. 6%, $100 par.
Common Stock 315,438,398 shs.

MARKET CAP: $26 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
4127.9	4202.5	4486.4	4246.4	4519.0	4997.1	5926.1	7472.3	7648.5	7679.5	**7900**	**8200**	Revenues ($mill)	**9300**
378.4	455.6	514.0	547.5	578.6	589.5	640.3	940.2	998.2	1060.5	**1115**	**1180**	Net Profit ($mill)	**1420**
36.5%	35.4%	33.9%	35.9%	36.9%	38.0%	40.4%	37.6%	37.2%	13.8%	**11.0%**	**11.0%**	Income Tax Rate	**11.0%**
25.0%	18.6%	16.8%	9.4%	4.5%	1.3%	4.5%	3.8%	1.6%	2.1%	**3.0%**	**3.0%**	AFUDC % to Net Profit	**2.0%**
51.9%	50.6%	53.6%	51.7%	50.6%	48.5%	51.2%	50.5%	48.0%	50.4%	**50.0%**	**47.5%**	Long-Term Debt Ratio	**50.0%**
47.7%	49.0%	46.0%	48.0%	49.1%	51.2%	48.6%	49.3%	51.9%	49.4%	**50.0%**	**52.5%**	Common Equity Ratio	**50.0%**
7473.1	7764.5	8608.0	8619.3	8626.6	8636.5	17809	18118	18238	19813	**20200**	**19925**	Total Capital ($mill)	**23225**
9070.5	9601.5	10160	10572	10907	11258	19190	19916	21347	22001	**24350**	**26525**	Net Plant ($mill)	**30950**
6.4%	7.5%	7.5%	7.9%	8.1%	8.1%	4.5%	6.3%	6.6%	6.5%	**6.5%**	**7.0%**	Return on Total Cap'l	**7.5%**
10.5%	11.9%	12.9%	13.1%	13.6%	13.2%	7.4%	10.5%	10.5%	10.8%	**11.0%**	**11.0%**	Return on Shr. Equity	**12.0%**
10.6%	12.0%	12.9%	13.2%	13.6%	13.3%	7.4%	10.5%	10.5%	10.8%	**11.0%**	**11.5%**	Return on Com Equity E	**12.0%**
6.2%	7.0%	6.6%	6.5%	5.9%	5.3%	2.1%	3.5%	3.6%	3.7%	**3.5%**	**3.5%**	Retained to Com Eq	**4.0%**
42%	41%	47%	51%	57%	60%	71%	67%	66%	66%	**67%**	**67%**	All Div'ds to Net Prof	**67%**

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+18.5	-3.0	+2.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Lg. C&I Revs. per KWH (¢)	7.08	7.13	7.05
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.7	+.7
Fixed Charge Cov. (%)	404	422	323

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	3.0%	4.5%	3.5%
"Cash Flow"	7.0%	7.5%	7.0%
Earnings	8.5%	6.0%	6.0%
Dividends	15.5%	11.0%	6.0%
Book Value	8.5%	10.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2194	1602	1712	1963	7472.3
2017	2304	1632	1657	2055	7648.5
2018	2287	1672	1644	2077	7679.5
2019	2377	**1700**	**1700**	**2123**	**7900**
2020	**2450**	**1750**	**1750**	**2250**	**8200**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.09	.57	.68	.61	2.96
2017	1.12	.63	.68	.71	3.14
2018	1.23	.73	.74	.65	3.34
2019	1.33	**.72**	**.76**	**.71**	**3.52**
2020	**1.30**	**.80**	**.85**	**.75**	**3.70**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.4225	.4225	.44	.4575	1.74
2016	.495	.495	.495	.495	1.98
2017	.52	.52	.52	.52	2.08
2018	.5525	.5525	.5525	.5525	2.21
2019	.59	.59			

BUSINESS: WEC Energy Group, Inc. (formerly Wisconsin Energy) is a holding company for utilities that provide electric, gas & steam service in WI & gas service in IL, MN, & MI. Customers: 1.6 mill. elec., 2.9 mill. gas. Acq'd Integrys Energy 6/15. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 35%; small commercial & industrial, 31%; large commercial & industrial, 21%; other, 13%. Generating sources: coal, 45%; gas, 22%; renewables, 4%; purchased, 29%. Fuel costs: 38% of revenues. '18 reported deprec. rates (utility): 2.0%-3.2%. Has 7,900 employees. Chairman: Gale E. Klappa. President & CEO: Kevin Fletcher. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wecenergygroup.com.

WEC Energy's utilities in Wisconsin have filed general rate cases. Wisconsin Electric and Wisconsin Public Service are seeking electric increases totaling $132 million in each of 2020 and 2021. Wisconsin Electric, Wisconsin Public Service, and Wisconsin Gas filed for gas hikes totaling $33 million in 2020. WPS is seeking another $7 million for gas in 2021. Wisconsin Electric and WPS requested allowed returns on equity of 10.35%, slightly above their currently allowed ROEs. Wisconsin Gas filed for the same 10.3% ROE it is currently allowed. The utilities are all asking for a slight boost in their common-equity ratio, to 52%. A ruling from the Wisconsin commission is expected in time for new tariffs to take effect at the start of 2020.

A gas-fired power plant began operation at the end of March. The new facility, in the upper peninsula of Michigan, allowed the company to retire a coal-fired plant. This ought to reduce annual operating and maintenance costs by $40 million. The plant's cost was $255 million, below the budgeted level. The utility will recover half of the facility's cost in rates and the other half through a 20-year contract to sell power to a large industrial customer.

We expect solid earnings growth in 2019 and 2020. The company's utility in Chicago, Peoples Gas, is spending $280 million-$300 million annually to replace old pipes, and recovering these expenditures through a rider on customers' bills. The year got off to a good start (due in part to favorable weather conditions), so management is now aiming for the upper end of its targeted earnings range of $3.48-$3.52 a share. Our 2020 estimate of $3.70 is based on the assumption of reasonable regulatory treatment in Wisconsin.

The company is adding renewable energy projects. WPS expects to pay $260 million for 200 megawatts of solar capacity. A nonutility subsidiary is investing in wind projects, which should produce a higher return on investment than that of the regulated utilities.

The price of this high-quality stock has risen 17% in 2019. The market recognizes WEC Energy's steady earnings and dividend growth. However, neither the yield nor 3- to 5-year total return potential stands out among utility issues.

Paul E. Debbas, CFA *June 14, 2019*

(A) Diluted EPS. Excl. gains on discont. ops.: '04, 77¢; '11, 6¢; nonrecurring gain: '17, 65¢. '16 & '18 EPS don't sum due to rounding. Next earnings report due early August. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '18: $21.74/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '15: 10.0%-10.3%; in IL in '15: 9.05%; in MN in '16: 9.11%, in MI in '16: 9.9%; earned on avg. com. eq., '18: 11.0%. Regulatory Climate: WI, Above Avg.; IL, Below Avg.; MN & MI, Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	90

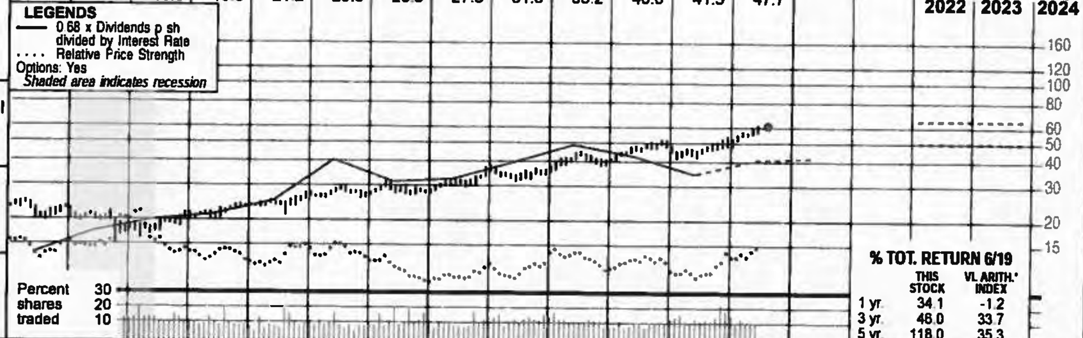
XCEL ENERGY NDQ-XEL

RECENT PRICE	61.00	P/E RATIO	23.5 (Trailing: 24.3, Median: 15.0)	RELATIVE P/E RATIO	1.37	DIV'D YLD	2.7%	VALUE LINE

TIMELINESS	1 Raised 3/22/19
SAFETY	1 Raised 5/1/15
TECHNICAL	3 Lowered 7/26/19
BETA .50 (1.00 = Market)	

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	62.0
Low:	15.3	16.0	19.8	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7

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



Target Price Range
2022 | 2023 | 2024

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+5%)	5%
Low	50	(-20%)	-1%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	1	0	0	0	0	0	0	0	0
Options	0	1	0	1	0	14	1	0	7
to Sell	1	0	0	0	0	1	3	0	1

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	296	360	353
to Sell	308	294	308
Hld's(000)	382071	392248	396450

Percent shares traded 30 20 10

% TOT. RETURN 6/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.1	-1.2
3 yr.	46.0	33.7
5 yr.	118.0	35.3

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	23.25	23.85	Revenues per sh	26.25
3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.65	"Cash Flow" per sh	8.00
1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.60	2.75	Earnings per sh A	3.25
.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	Div'd Decl'd per sh B ■	2.05
2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	9.15	6.95	Cap'l Spending per sh	7.25
12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	24.80	25.90	Book Value per sh C	29.50
398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	516.00	518.00	Common Shs Outst'g D	525.00
11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	17.5
.66	.72	.82	.80	.89	.82	85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	*Value Line*		Relative P/E Ratio	.95
5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	*estimates*		Avg Ann'l Div'd Yield	3.6%

CAPITAL STRUCTURE as of 3/31/19
Total Debt $17372 mill. **Due in 5 Yrs** $4491 mill.
LT Debt $16118 mill. **LT Interest** $676 mill.
Incl. $145 mill. capitalized leases.
(LT interest earned: 2.8x)

Leases, Uncapitalized Annual rentals $239 mill.
Pension Assets-12/18 $2742 mill. **Oblig** $3477 mill.

Pfd Stock None

Common Stock 514,673,191 shs.
as of 4/18/19
MARKET CAP: $31 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
9644.3	10311	10655	10128	10915	11686	11024	11107	11404	11537	12000	12350	Revenues ($mill)	13800
685.5	727.0	841.4	905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1335	1425	Net Profit ($mill)	1725
35.1%	37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	9.0%	9.0%	Income Tax Rate	9.0%
16.8%	11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	10.0%	9.0%	AFUDC % to Net Profit	7.0%
51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	57.5%	58.0%	Long-Term Debt Ratio	58.0%
47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	42.5%	42.0%	Common Equity Ratio	42.0%
15277	17452	17331	19018	20477	21714	23092	25216	25975	28025	30175	31950	Total Capital ($mill)	36900
18508	20663	22353	23809	26122	28757	31206	32842	34329	36944	39775	41350	Net Plant ($mill)	45400
6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.5%	5.5%	Return on Total Cap'l	6.0%
9.3%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.5%	10.5%	Return on Shr. Equity	11.0%
9.4%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.5%	10.5%	Return on Com Equity E	11.0%
3.7%	3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.0%	4.0%	Retained to Com Eq	4.0%
61%	59%	56%	54%	54%	55%	57%	61%	62%	58%	63%	62%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+.3	-.7	+3.2
Large C & I Use (MWH)	22519	22642	23004
Large C & I Revs. per KWH (¢)	6.17	6.36	5.91
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20423	19591	20293
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+1.1
Fixed Charge Cov. (%)	342	330	281

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-1.0%	.5%	3.0%
"Cash Flow"	4.5%	6.5%	6.5%
Earnings	5.5%	5.0%	5.5%
Dividends	4.5%	6.0%	6.0%
Book Value	4.5%	4.5%	4.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2772	2500	3040	2795	11107
2017	2946	2645	3017	2796	11404
2018	2951	2658	3048	2880	11537
2019	3141	2709	3150	3000	12000
2020	3250	2750	3250	3100	12350

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.47	.39	.90	.45	2.21
2017	.47	45	.97	.42	2.30
2018	.57	.52	.96	.42	2.47
2019	.61	.50	1.03	.46	2.60
2020	.63	.52	1.10	.50	2.75

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.30	.32	.32	.32	1.26
2016	.32	.34	.34	.34	1.34
2017	.34	.36	.36	.36	1.42
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405		

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.6 mill. electric, 2.0 mill. gas. Elec. rev. breakdown: residential, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 41% of revs. '18 reported depr. rate: 3.1%. Has 11,100 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy has reached a partial settlement regarding its proposed purchase of a gas-fired generating plant. The utility agreed to pay $650 million for a 760-megawatt facility in Minnesota. This is part of Xcel's integrated resource plan in the state, which calls for the early retirement of two coal-fired units in 2028 and 2030, with the utility recovering the undepreciated balance of its investments. The asset acquisition is expected to close in the current quarter. In a separate deal, Xcel agreed to pay $135 million to buy out 70 mw of purchased-power agreements with wind generators.

Public Service of Colorado filed an electric rate case. The utility is seeking an increase of $158.3 million (5.7%), based on a 10.35% return on a 56.46% common-equity ratio. PSCo wants to place capital additions in the rate base and recover higher deprecation and incremental costs associated with wildfire mitigation. New tariffs are expected to take effect at the start of 2020.

Rate cases are pending in Wisconsin and New Mexico, and others are upcoming. In Wisconsin, the utility filed for no change in electric rates and a slight decrease in gas rates. This reflects the pass-through to customers of the benefits of federal tax reform. Southwestern Public Service asked the New Mexico commission for a hike of $51 million, based on a 10.35% return on a 54.8% common-equity ratio. and plans to file in Texas this summer. Xcel will put forth a petition in Minnesota in early November.

Rate relief is a key factor in the profit growth we expect this year and next. Our 2019 share-net estimate is at the midpoint of Xcel's targeted range of $2.55-$2.65. We estimate an increase of 6%, to $2.75, in 2020. The company's goal for annual earnings and dividend growth is 5%-7%.

This stock has our top ranks for Timeliness and Safety. However, the valuation is well above its historical level. (Note the lofty relative price-earnings ratio.) Like most utility issues, the recent quotation is well within our 2022-2024 Target Price Range. The dividend yield does not stand out among utilities, and 3- to 5-year total return potential is negligible.

Paul E. Debbas, CFA *July 26, 2019*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (losses) on discontinued ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢ '17 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid mid-Jan., Apr., July and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '18: $5.92/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '18: 10.4%. Regulatory Climate: Average.

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

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-065

REQUEST:

Provide all bond rating agency reports (Standard and Poor's, Moody's, Fitch) on Duke Energy and Duke Energy Kentucky from 2017 through the most recent month in 2019.

RESPONSE:

For 2018 and 2019, see STAFF-DR-02-050(a).

For 2017, see AG-DR-01-065 Attachment.

PERSON RESPONSIBLE: Christopher M. Jacobi

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
4 January 2017

Update

Rate this Research

RATINGS

Duke Energy Kentucky, Inc.

Domicile	Kentucky, United States
Long Term Rating	Baa1
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date

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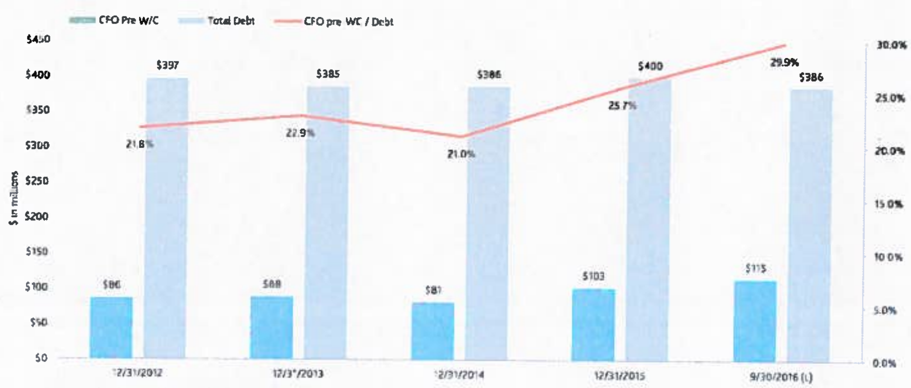
Duke Energy Kentucky, Inc.

Regulated utility subsidiary of Duke Energy Corporation

Summary Rating Rationale

Duke Energy Kentucky Inc.'s (Duke Kentucky) rating reflects cash flow and financial coverage ratios that are appropriate for its Baa1 rating despite base rate freezes that have been in place since 2012; capital expenditures that are on the rise; and the support of the Duke Energy corporate family. Ratings are constrained by its relatively small stand-alone size and position as a subsidiary of Baa1 rated Duke Energy Ohio, Inc. (Duke Ohio). Although we have traditionally considered Kentucky to be a credit supportive regulatory environment for investor owned utilities, Duke Kentucky has had a limited regulatory track record with regard to base rate cases in recent years.

Exhibit 1
Historical CFO Pre-W/C, Total Debt, and CFO Pre-W/C to Debt



Source: Moody's Financial Metrics

Credit Strengths

» Solid cash flow coverage ratios

» Generally credit supportive regulation in Kentucky

» Support of the Duke Energy corporate family

Credit Challenges

» Base rate freezes in place since 2012

» Capital expenditures are increasing

» Limited recent regulatory track record

» Small size and position as wholly-owned subsidiary of Duke Ohio

Rating Outlook

The stable rating outlook considers the generally credit supportive regulatory environment in Kentucky, financial metrics that are appropriate for Duke Kentucky's rating level, and increasing capital expenditures.

Factors that Could Lead to an Upgrade

» A material increase in base rates

» Cash from operations excluding working capital changes to debt remain in the mid-20% range on a sustained basis

» An upgrade of Duke Ohio from its current Baa1 rating level

Factors that Could Lead to a Downgrade

» Cash flow from operations excluding working capital changes to debt falling to the mid-teens

» Higher capital expenditures resulting in a material increase in debt levels

» A decline in the credit supportiveness of the regulatory environment in Kentucky

Key Indicators

Exhibit 2
Duke Energy Kentucky, Inc.

	12/31/2012	12/31/2013	12/31/2014	12/31/2015	9/30/2016(LTM)
CFO pre-WC + Interest / Interest	5.7x	6.1x	5.7x	7.8x	8.2x
CFO pre-WC / Debt	21.8%	22.9%	21.0%	25.7%	29.9%
CFO pre-WC – Dividends / Debt	19.3%	12.6%	21.0%	11.9%	24.7%
Debt / Capitalization	39.2%	37.8%	36.2%	36.6%	34.0%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Detailed Rating Considerations

Cash flow coverage ratios remain solid

Duke Kentucky's cash flow and key financial metrics have been appropriate for its Baa1 rating for the last several years even though it has operated under base rate freezes since 2012. The ratio of cash from operations excluding changes in working capital (CFO pre-W/C) to debt remained above 20%, and recently moved above the 22% threshold at the lower end of the "A" scoring range for this factor in our Regulated Electric and Gas Utilities rating methodology scorecard. The recent improvement in metrics is due in part to the continued extension of bonus depreciation and the resulting increase in deferred income taxes. Going forward, as the company implements its growing capital expenditure program, we expect credit metrics to moderate, but to remain appropriate for its Baa1 rating.

Generally credit supportive Kentucky regulation but Duke Kentucky has a limited recent regulatory track record

We generally view the Kentucky regulatory environment as reasonably credit supportive, with utilities in the state benefitting from timely cost recovery mechanisms, including recovery of fuel, purchased power, and environmental compliance costs. However, the utility has not filed for a base rate increase in several years, resulting in a limited recent regulatory track record. Duke Kentucky's approach to base rate filings has been different from some other utilities in the state, particularly those with large capital expenditure programs. PPL Corporation's (Baa2 stable) subsidiaries Kentucky Utilities (A3 stable) and Louisville Gas & Electric (A3 stable), for example, filed for base rate increases in June 2012, and again in November 2014. Rate relief granted in these cases helped these utilities maintain strong CFO pre-working capital to debt ratios in the 25% range, somewhat higher than those experienced by Duke Kentucky from 2012 through 2014. More recently however, Duke Kentucky's metrics are on par with these peer companies.

In December 2015, Duke Kentucky received Kentucky Public Service Commission (KPSC) approval to defer costs incurred for complying with the Environmental Protection Agency's (EPA) regulations for the disposal of coal combustion residuals, including carrying costs; however, recovery would not likely begin until the next rate proceeding. The utility is also seeking approval for an advanced metering infrastructure project for which it is requesting deferral accounting (recovery in a future rate case). On the other hand, the PPL utilities, in January 2016, filed for recovery of the cost of projects related to regulations for coal and combustion by products and mercury and air toxics standards via an environmental cost recovery surcharge (rapid rider recovery).

Base rate freezes have suppressed metrics to some extent

As a result of base rate freezes entered into to facilitate either the utility or the parent company's strategic objectives, financial performance at Duke Kentucky was somewhat constrained over the 2012-2014 period. For example, as part of a settlement with the Kentucky Public Service Commission (KPSC) approving the merger of parent company Duke Energy with Progress Energy, the utility agreed that it would not file an electric or gas base rate case for two years through mid-2013. Although this rate freeze expired, the utility did not file for any base rate relief despite declining financial metrics at the time (CFO pre-W/C to debt was 23% in 2013 versus 27% in 2011). As part of a 2014 stipulation with the Kentucky attorney general related to the acquisition of a 31% interest in the East Bend coal plant, the utility agreed to a second base rate freeze and agreed not to file for a base rate increase until January 2016. To date, no general rate case has been filed. Despite the base rate freezes, the utility did maintain an ability to seek emergency rate relief in the event its financial condition deteriorates materially.

Capital expenditures are on the rise

Base rate relief may be necessary as the utility enters a period of higher capital expenditures, partly for environmental compliance. During the second quarter of 2015, as a result of the EPA's published rule on the regulation of coal ash or coal combustion residuals (CCR), Duke Kentucky recorded additional asset retirement obligation (ARO) amounts for estimated ash basin closure costs at its East Bend coal plant. In July 2016, Duke Kentucky filed with the KPSC for a certificate of public convenience and necessity (CPCN) to convert to dry bottom ash at the East Bend Station. If approved, the cost of the project is currently estimated at $23 million. Cost recovery of these expenditures will be pursued through the normal ratemaking process with the KPSC, which could result in some regulatory lag. In addition, in April of 2016, Duke Kentucky filed an application for the construction of advanced metering infrastructure (AMI), which is expected to cost $49 million and would take two years to complete. On December 6, 2016, a settlement on the AMI investment was reached between the Attorney General and Duke Kentucky which the KPSC is now reviewing.

On the gas side, in February 2016, the KPSC approved a settlement agreement that provided rider recovery for Duke Kentucky's five year accelerated natural gas service line replacement program, which is expected to cost about $38 million. Duke Kentucky's first required annual ASRP projections and tariffs were filed with the KPSC in July 2016, the rates were approved in December 2016, and became effective January 2017. In May 2016, Duke Kentucky filed a request with the KPSC for approval of the construction of a new natural gas pipeline that would provide additional needed capacity and increase the reliability of its system. The project is expected to cost approximately $14 million and is currently under review by the KPSC.

Small size and position as wholly-owned subsidiary of Duke Ohio are rating constraints

Duke Kentucky is the smallest utility in the Duke Energy system and is wholly owned by a neighboring Duke utility subsidiary, Duke Ohio (Baa1 stable), which is a fully regulated transmission and distribution company. Although Duke Kentucky does not file financial statements with the SEC, it does publish quarterly and audited annual financial statements on its web site. The combination of the utility's small size and its position as a wholly owned subsidiary of a Baa1 rated affiliate utility are both rating constraints.

Liquidity Analysis

Duke Kentucky maintains an adequate liquidity profile. In 2015, the utility generated cash from operations of about $110 million, made about $69 million in capital investments and paid dividends of $55 million to its parent, generating about $14 million of negative cash flow. For the twelve months ending September 2016, cash flow from operations of about $94 million was about $19 million less than the combination of $93 million of funds utilized for capital expenditures and $20 million for dividends. Going forward, due to its increasing capital needs, we anticipate the utility will remain cash flow negative; shortfalls are expected to be funded via a combination of debt and equity contributions from Duke Energy.

Duke Kentucky's additional liquidity sources include its access to funding from the Duke parent company's commercial paper program through the Duke system money pool, and from direct borrowings from the money pool. As of September 30, 2016, the utility also has $150 million of direct borrowing capacity under Duke Energy's master five year credit facility, of which $125 million was available. The $7.5 billion Duke Energy credit facility matures on 30 January 2020 and does not contain a material adverse change clause for new borrowings. The facility contains a single financial covenant requiring Duke Energy and its major utility subsidiaries (not including Duke Kentucky) to maintain a consolidated debt to capitalization ratio of no more that 65%. As of September 30, 2016, each company was in compliance with this covenant.

Duke Kentucky's next large debt maturity is $100 million of senior unsecured debt due in October 2019. As of 30 September 2016, additional short-term obligations of $27 million (tax-exempt bonds) and $25 million (money pool borrowings) were classified as long-term debt and long-term debt payable to affiliated companies, respectively, due to the company's intent and ability to utilize such borrowings as long-term financing. The utility has the ability to refinance these short-term obligations on a long-term basis due to Duke Energy's master credit facility and other bilateral letter of credit agreements that have non-cancelable terms in excess of one year.

Rating Methodology and Scorecard Factors

Exhibit 3
Duke Energy Kentucky, Inc.

Rating Factors				
Duke Energy Kentucky, Inc.				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2016		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity	B	B	B	B
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.8x	Aa	6.8x - 7.2x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	24.9%	A	19% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	20.1%	A	17% - 21%	A
d) Debt / Capitalization (3 Year Avg)	35.4%	A	35% - 40%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2016(LTM);
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Corporate Profile

Duke Kentucky is a wholly owned subsidiary of Duke Ohio and its ultimate parent, Duke Energy Corporation. Duke Kentucky is a vertically integrated electric and gas utility company that owns and operates approximately 1,100 megawatts (MWs) of regulated generation facilities and provides electricity to around 140,000 electric customers in northern Kentucky. Duke Kentucky also provides natural gas services to approximately 100,000 customers in the same area. The company is regulated primarily by the Kentucky Public Service Commission (KPSC).

Ratings

Exhibit 4

Category	Moody's Rating
DUKE ENERGY KENTUCKY, INC.	
Outlook	Stable
Senior Unsecured	Baa1
ULT PARENT: DUKE ENERGY CORPORATION	
Outlook	Negative
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Jr Subordinate	Baa2
Commercial Paper	P-2
PARENT: DUKE ENERGY OHIO, INC.	
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured Shelf	(P)A2
Senior Unsecured	Baa1

Source: Moody's Investors Service

REPORT NUMBER 1054347

MOODY'S
INVESTORS SERVICE

AG-DR-01-066

REQUEST:

Provide copies of all articles and publications cited by Dr. Morin in his Direct Testimony.

RESPONSE:

See response to AG-DR-01-064.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

AG-DR-01-067

REQUEST:

On page 4, lines 18–19 of his Direct Testimony Dr. Morin testified that his recommended ROE range is required for Duke Energy Kentucky to "maintain its financial integrity." Provide all analyses and quantifications performed by Dr. Morin or any and all personnel at Duke Energy and/or Duke Energy Kentucky that support this statement. Provide any spreadsheets analyses with cell formulas intact.

RESPONSE:

The essence and the ultimate test of the validity of a rate of return estimate is whether it will permit the company to attract capital on reasonable terms and maintain the company's financial integrity. According to the seminal standards laid down in the landmark *Hope* and *Bluefield* cases, the return allowed by the regulator must be such as (1) to permit the utility to attract capital and maintain integrity, and (2) to be comparable with returns on similar risk investments. There are many dimensions and factors that determine a utility's financial integrity. The notion of integrity is fluid and encompasses several considerations, and no one single measure or spreadsheet analysis can capture the adequacy of integrity.

It is transparent that return on equity and interest coverage, which is a pivotal standard used by capital markets with respect to the attraction of debt capital, are related. The return should also be high enough to produce interest coverages consistent with an optimal cost-efficient bond rating. A return on equity that produces inadequate interest coverage endangers debt capital attraction. If the coverage implied by a recommended return on equity is below current bond rating benchmarks, then an anemic coverage would almost guarantee a further downgrading of a company's bonds, particularly if interest coverages were already marginal. This can be further damaging if the company is pursuing a substantial construction expenditure program and requires external financing in a volatile and quality-conscious capital market. If the coverage ratio implied by any cost of equity estimate is well outside that of its peers, then this should attest to the inadequacy of the estimate. As a result, existing bondholders would be inflicted a capital loss, and the cost of capital, hence ratepayer burden, would increase. This is in direct violation of the fundamental doctrine of capital attraction and financial integrity promulgated by the landmark *Hope* and *Bluefield* cases.

The Company's current financial integrity and access to capital are based on: 1) a ROE that is commensurate with the Company's risks and other opportunities available to investors, which is what Dr. Morin has quantified in all his exhibits of his testimony, and 2) investors' expectations of continuity in supportive regulatory treatment, that is, regulatory treatment that allows the Company a reasonable chance of actually earning its allowed return.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

AG-DR-01-068

REQUEST:

Provide any analyses performed by Dr. Morin or other persons at Duke Energy or DEK that quantify the credit metrics used by Standard and Poor's and/or Moody's showing that Dr. Morin's recommended ROE is necessary to maintain Duke Energy Kentucky's financial integrity. If no such analyses were performed, so state.

RESPONSE:

Dr. Morin did not perform such analyses, as this was well outside the scope of his testimony. Also, no other persons at Duke Energy performed such specific analyses. However, in its January 29, 2019 credit opinion, Moody's notes that "credit metrics are expected to weaken" in its list of credit challenges. Any reduction in ROE would weaken the Company's credit metrics due to a corresponding reduction in cash flow.

PERSON RESPONSIBLE: Christopher M. Jacobi

AG-DR-01-069

REQUEST:

Provide the following:

a. The current authorized ROE for each Duke Energy operating company and the date that each ROE was authorized.

b. Provide the Commission Order authorizing each ROE listed in part a.

c. State whether each ROE was authorized pursuant to a fully litigated rate case or if it was based on a settlement.

RESPONSE:

Please see AG-DR-01-069 Attachment.

PERSON RESPONSIBLE: William Don Wathen Jr.

Company	Current Authorized ROE	Order/Docket No.	Date	Settled/Litigated
Duke Energy Ohio, Inc	9.84 percent	17-32-EL-AIR	12/19/2018	Settled
Duke Energy Indiana, LLC	10.5 percent	Cause No. 42359	5/18/2004	Litigated
Duke Energy Carolinas (NC)	9.9 percent	E-7 Sub 1146	6/22/2018	Partial Settlement including ROE
Duke Energy Progress (NC)	9.9 percent	E-2 Sub 1142	2/23/2018	Partial Settlement including ROE
Duke Energy Florida	10.5 percent	PSC-2017-0451-AS-EU	11/20/2017	Settled
Duke Energy Carolinas (SC)	9.5 percent	2019-323	5/21/2019	Litigated
Duke Energy Progress (SC)	9.5 percent	2019-341	5/21/2019	Litigated
Piedmont (NC)	9.7 percent	G-9, Sub 743	Pending	Settled
Piedmont (SC)	9.9 percent	2019-7-G- Order No. 2019-730	10/15/2019	Settled
Piedmont (TN)	10.2 percent	11-00144	12/21/2011	Settled

PUBLIC AG-DR-01-070
(AS TO ATTACHMENT)

REQUEST:

Refer to Attachment RAM-9. Provide the Authorized Electric Returns by utility for 2019.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

See AG-DR-01-070 CONFIDENTIAL Attachment. This confidential attachment will be provided to all parties upon the execution of a Confidentiality Agreement.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

2019-00271
AG-DR-01-070
ATTACHMENT
IS BEING FILED
UNDER SEAL

AG-DR-01-071

REQUEST:

If not provided previously, provide a copy of the source document from S&P Global Intelligence for the authorized electric returns shown in Attachment RAM-9.

RESPONSE:

See response to AG-DR-01-070.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

AG-DR-01-072

REQUEST:

Provide DEK's capital expenditures by year from 2019 through 2025.

RESPONSE:

Please see response to STAFF-DR-02-100. The company does not have a forecast for capital expenditures beyond 2023.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-073

REQUEST:

Refer to Dr. Morin's Direct Testimony, page 62, lines 15–21. Provide copies of studies in Dr. Morin's possession showing the size effect specifically for electric and/or combination electric and gas utilities.

RESPONSE:

See AG-DR-01-073 Attachment for an article which estimates the impact of size on utility company returns.

Chapter 7 of Duff & Phelps 2019 Valuation Yearbook contains a comprehensive study of the effect of size on return involving more than 3000 company stocks, many of which are utility companies.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

Financial News

By Michael Annin

Equity and the Small-Stock Effect

The capital asset pricing model shows risk inherent in return on equity. But something goes wrong when it's used for small-sized companies.

Does the size of a company affect the rate of return it should earn? If smaller companies should earn a higher return than larger firms, then small utilities, because of their size, should be allowed to adjust the rates they charge to customers.

By far the most notable and well-documented apparent anomaly in the stock market is the effect of company size on equity returns. The first study focusing on the impact that company size exerts on security returns was performed by Rolf W. Banz. Banz sorted New York Stock Exchange (NYSE) stocks into quintiles based on their market capitalization (price per share times number of shares outstanding), and calculated total returns for a value-weighted portfolio of the stocks in each quintile. His results indicate that returns for companies from the smallest quintile surpassed all other quintiles, as well as the Standard & Poor's 500 and other large stock indices. A number of other researchers have replicated Banz's work in other countries; nevertheless, a consensus has not yet been formed on why small stocks behave as they do.

One explanation for the higher returns is the lack of information on small companies. Investors must search more diligently for data. For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.

The Flaw in CAPM

One of the more common cost of equity models used in practice today is the capital asset pricing model (CAPM). The CAPM describes the expected return on any company's stock as proportional to the amount of systematic risk an investor assumes. The traditional CAPM formula can be stated as:

$$R_s = [\beta_s \times RP] + R_f$$

where:

R_s = expected return or cost of equity on the stock of company "s"
β = the *beta* of the stock of company "s"
RP = the expected equity risk premium
R_f = expected return on a riskless asset.

Table 1: The Size Premium in CAPM
(By Decile Portfolio in NYSE, 1926-94)

Decile	*Beta*	Arithmetic Mean Return	Actual Return in Excess of Riskless Rate**	CAPM Return in Excess of Riskless Rate**	Size Premium (Return in Excess CAPM)
1	0.90	11.01%	5.88%	6.33%	-0.44%
2	1.04	13.09	7.97	7.34	0.63
3	1.09	13.83	8.71	7.70	1.01
4	1.13	14.44	9.32	7.98	1.33
5	1.17	15.50	10.38	8.22	2.16
6	1.19	15.45	10.33	8.38	1.95
7	1.24	15.92	10.79	8.75	2.05
8	1.29	16.84	11.72	9.05	2.67
9	1.36	17.83	12.71	9.57	3.14
10	1.47	21.98	16.86	10.33	6.53

*Betas are estimated from monthly returns in excess of the 20-year government bond income return, January 1926-December 1994.
**Historical riskless rate measured by the 69-year arithmetic mean income return component of 20-year government bonds.
Source: SBBI 1995 Yearbook

Table 2: CAPM vs. CAPM w/ Size Premium

(By Percentile for Electric, Gas, and Sanitary Services Utilities)

	CAPM	CAPM with Size Premium
90th Percentile	16.42%	18.92%
75th Percentile	12.56%	14.72%
Median	10.89%	12.58%
25th Percentile	9.86%	11.39%
10th Percentile	8.63%	10.65%

(Weighted by Market Capitalization)

	CAPM	CAPM with Size Premium
Industry Composite	11.76%	12.33%
Large Company Composite	12.05%	12.07%
Small Company Composite	13.93%	17.95%

Source: Cost of Capital Quarterly '95 Yearbook by Ibbotson Associates
Note: Public utilities include electric, gas, and sanitary services companies.

Table 1 shows *beta* and risk premiums over the past 69 years for each decile of the NYSE. It shows that a hypothetical risk premium calculated under the CAPM fails to match the actual risk premium, shown by actual market returns. The shortfall in the CAPM return rises as company size decreases, suggesting a need to revise the CAPM.

The risk premium component in the actual returns (realized equity risk premium) is the return that compensates investors for taking on risk equal to the risk of the market as a whole (estimated by the 69-year arithmetic mean return on large company stocks, 12.2 percent, less the historical riskless rate). The risk premium in the CAPM returns is *beta* multiplied by the realized equity risk premium.

The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premiums (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.

Based on this analysis, we modify the CAPM formula to include a small-stock premium. The modified CAPM formula can be stated as follows:

$$R_s = [\beta_s \times RP] + R_f + SP$$

where:

SP = small-stock premium.

Because the small-stock premium can be identified by company size, the appropriate premium to add for any particular company will depend on its equity capitalization. For instance, a utility with a market capitalization of $1 billion would require a small capitalization adjustment of approximately 1.3 percent over the traditional CAPM; at $400 million, approximately 2.1 percent, and at only $100 million, approximately 4 percent.

Again, these additions to the traditional CAPM represent an adjustment over and above any increase already provided to these smaller companies by having higher *betas*.

Implications for Smaller Utilities

These findings carry important ramifications for relatively small public utilities. Boosting the traditional CAPM return by a full 400 basis points for small utilities translates into a substantial premium over larger utilities.

Table 2 shows the results of an analysis of 202 utility companies that calculated cost of equity figures. Composites (arithmetic means) weighted by equity capitalization were also calculated for the largest and smallest 20 companies. The results show the impact size has on cost of equity.

For the traditional CAPM, the large-company composite shows a cost of equity of 12.05 percent; the small company composite, 13.93 percent. However, once the respective small capitalization premium is added in, the spread increases dramatically, to 12.07 and 17.95 percent, respectively. Clearly, the smaller the utility (in terms of equity capitalization), the larger the impact that size exerts on the expected return of that security. ▼

Michael Annin, CFA, is a senior consultant with Ibbotson Associates, specializing in business valuation and cost of capital analysis. He oversees the Cost of Capital Quarterly, *a reference work on using cost of capital for company valuations.*

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

PUBLIC AG-DR-01-074
(As to Attachment only)

REQUEST:

Provide DEK's historical capital structure for the last 10 years. Show the components of common stock, long-term debt, and short term debt separately. Show both the amounts and percentages for each component.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

Please see AG-DR-01-074 Confidential Attachment. This confidential attachment will be provided to all parties upon the execution of a Confidentiality Agreement.

PERSON RESPONSIBLE: Danielle Weatherston

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Kentucky, Inc.

Case No. 2019-00271
Capital Structure
12 Months Ended December
Dollars In Thousands

Line No.	Type of Capital	2018		2017		2016		2015		2014	
		Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1.	Long Term Debt [1,3]	$ 550,111	48.0%	$ 451,180	46.9%	$ 362,046	44.2%	$ 319,027	40.9%	$ 320,786	41.6%
2.	Short-Term Debt	-	0.0%	-	0.0%	19,656	2.4%	55,743	7.2%	37,609	4.9%
3.	Preferred & Preference Stock	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
4.	Common Stock [2]	226,274	19.7%	191,274	19.9%	176,274	21.5%	176,274	22.6%	176,274	22.8%
5.	Retained Earnings	369,950	32.3%	320,140	33.3%	260,741	31.8%	228,157	29.3%	236,982	30.7%
6.	Total Capitalization	$ 1,146,335	100.0%	$ 962,594	100.1%	$ 818,717	99.9%	$ 779,201	100.0%	$ 771,651	100.0%

Line No.	Type of Capital	2013		2012		2011		2010		2009		Sep-19	
		Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1.	Long Term Debt [1]	$ 339,053	47.3%	$ 340,840	47.8%	$ 342,786	49.1%	$ 344,589	42.5%	$ 345,544	45.0%	[redacted]	
2.	Short-Term Debt	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%		
3.	Preferred & Preference Stock	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%		
4.	Common Stock [2]	176,274	24.6%	176,274	24.7%	176,274	25.3%	176,274	21.8%	176,274	23.0%		
5.	Retained Earnings	201,679	28.1%	196,610	27.5%	178,390	25.6%	289,080	35.7%	245,819	32.0%		
6.	Total Capitalization	$ 717,006	100.0%	$ 713,724	100.0%	$ 697,450	100.0%	$ 809,943	100.0%	$ 767,637	100.0%		

(1) Includes current portion of Long Term Debt
(2) Includes Common Stock, Additional Paid in Capital, and Other Comprehensive Income
(3) 2014 and forward amounts include the unamortized debt expense amounts, in accordance with updated GAAP guidance

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Kentucky, Inc.
Case No. 2019-00271
Components of Common Equity
12 Months Ended December
Dollars In Thousands

Line No.	Item (a)	Common Stock [2] (f)	Retained Earnings (g)	Total Common Equity (h)
1	December 31, 2009	$ 176,274	$ 245,819	$ 422,093
2	December 31, 2010	176,274	289,080	465,354
3	December 31, 2011	176,274	178,390	354,664
4	December 31, 2012	176,274	196,610	372,884
5	December 31, 2013	176,274	201,679	377,953
6	December 31, 2014	176,274	236,982	413,256
7	December 31, 2015	176,274	228,157	404,431
8	December 31, 2016	176,274	260,741	437,015
9	December 31, 2017	191,274	320,140	511,414
10	December 31, 2018	226,274	369,950	596,224
11	September 30, 2019	[redacted]		

(2) Includes Common Stock, Additional Paid in Capital and Other Comprehensive Income

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-075

REQUEST:

Provide the amount, coupon, and maturity of each long-term debt instrument issued by DEK over the last 10 years.

RESPONSE:

Please see AG-DR-01-075 Attachment.

Additionally, Duke Energy Kentucky issued 3 tranches of debt in 2019:

	Tranche 3	Tranche 2	Tranche 1
PRINCIPAL AMOUNT	$95,000,000	$75,000,000	$40,000,000
MATURITY DATE	October 1, 2025	October 1, 2029	July 15, 2049
COUPON	3.230%	3.560%	4.320%

PERSON RESPONSIBLE: Danielle Weatherston

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223 - NONE		
4			
5	ACCOUNT 224		
6	UNSECURED DEBENTURES:		
7	5.00% SERIES DUE IN 2014	40,000,000	410,000
8			379,200 D
9	7.875% SERIES DUE IN 2009	20,000,000	170,547
10			51,600 D
11	5.75% SERIES DUE IN 2016	50,000,000	390,200
12			30,000 D
13	6.20% SERIES DUE IN 2036	65,000,000	653,550
14			357,900 D
15	2006 SER A POLLUTION CONTROL BONDS DUE IN 2027	50,000,000	178,560
16			
17	2006 SER B POLLUTION CONTROL BONDS DUE IN 2027	25,720,000	939,966
18			
19	TEPPCO-Todhunter Cavern Gas Storage	851,494	
20			
21	Long Term Notes Payable, variable rate	73,517,045	
22			
23	4.650% SERIES DUE IN 2019	100,000,000	756,468
24			374,000 D
25			
26	SUBTOTAL ACCOUNT 224	426,088,539	4,701,991
27			
28			
29	See footnote		
30			
31			
32			
33	TOTAL	426,088,539	4,701,991

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No
						1
						2
						3
						4
						5
						6
12/06/04	12/15/14	12/06/04	12/15/14	40,000,000	2,000,000	7
						8
09/15/99	09/15/09	09/15/99	09/15/09		1,115,875	9
						10
03/07/06	03/10/16	03/10/06	03/10/16	50,000,000	2,875,000	11
						12
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	13
						14
12/03/08	08/01/27	12/11/08	08/01/27	50,000,000	181,858	15
						16
07/26/06	08/01/27	08/02/06	08/01/27	26,720,000	363,741	17
						18
09/01/07	08/31/27			851,494		19
						20
09/25/08	2012				373,853	21
						22
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	1,342,687	23
						24
						25
				332,571,494	12,283,014	26
						27
						28
						29
						30
						31
						32
				332,571,494	12,283,014	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223 - NONE		
4			
5	ACCOUNT 224		
6	UNSECURED DEBENTURES:		
7	5.00% SERIES DUE IN 2014	40,000,000	410,000
8			379,200 D
9	5.75% SERIES DUE IN 2016	50,000,000	390,200
10			30,000 D
11	6.20% SERIES DUE IN 2036	65,000,000	653,550
12			367,900 D
13	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	178,560
14			
15	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	939,966
16			
17	TEPPCO-Todhunter Cavern Gas Storage	851,494	
18			
19	4.650% SERIES DUE IN 2019	100,000,000	755,468
20			374,000 D
21			
22	SUBTOTAL ACCOUNT 224	332,571,494	4,479,844
23			
24			
25			
26	See footnote		
27			
28			
29			
30			
31			
32			
33	TOTAL	332,571,494	4,479,844

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No
						1
						2
						3
						4
						5
						6
12/06/04	12/15/14	12/06/04	12/15/14	40,000,000	2,005,555	7
						8
03/07/06	03/10/16	03/10/06	03/10/16	50,000,000	2,867,014	9
						10
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,018,806	11
						12
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	171,454	13
						14
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	190,829	15
						16
09/01/07	08/31/27			851,494		17
						18
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,586,063	19
						20
						21
				332,571,494	13,839,721	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				332,571,494	13,839,721	33

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223 - NONE		
4			
5	ACCOUNT 224		
6	UNSECURED DEBENTURES:		
7	5.00% SERIES DUE IN 2014	40,000,000	410,000
8			379,200 D
9	5.75% SERIES DUE IN 2016	50,000,000	390,200
10			30,000 D
11	6.20% SERIES DUE IN 2036	65,000,000	653,550
12			367,900 D
13	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	691,754
14			
15	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	939,966
16			
17	TEPPCO-Todhunter Cavern Gas Storage	851,494	
18			
19	4.650% SERIES DUE IN 2019	100,000,000	756,468
20			374,000 D
21			
22	SUBTOTAL ACCOUNT 224	332,571,494	4,993,038
23			
24			
25			
26	See footnote		
27			
28			
29			
30			
31			
32			
33	TOTAL	332,571,494	4,993,038

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No
						1
						2
						3
						4
						5
						6
12/06/04	12/15/14	12/06/04	12/15/14	40,000,000	2,000,000	7
						8
03/07/06	03/10/16	03/10/06	03/10/16	50,000,000	2,875,000	9
						10
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	11
						12
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	173,149	13
						14
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	93,504	15
						16
07/31/07	07/31/27			851,494		17
						18
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,650,000	19
						20
						21
				332,571,494	13,821,653	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				332,571,494	13,821,653	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222 Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223 - NONE		
4			
5	ACCOUNT 224		
6	UNSECURED DEBENTURES:		
7	5.00% SERIES DUE IN 2014	40,000,000	410,000
8			379,200 D
9	5.75% SERIES DUE IN 2016	50,000,000	390,200
10			30,000 D
11	6.20% SERIES DUE IN 2036	65,000,000	653,550
12			367,900 D
13	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	691,754
14			
15	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	1,029,608
16			
17	TEPPCO-Todhunter Cavern Gas Storage	851,494	
18			
19	4.650% SERIES DUE IN 2019	100,000,000	756,468
20			374,000 D
21			
22	SUBTOTAL ACCOUNT 224	332,571,494	5,082,680
23			
24			
25			
26	See footnote		
27			
28			
29			
30			
31			
32			
33	TOTAL	332,571,494	5,082,680

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
12/06/04	12/15/14	12/06/04	12/15/14	40,000,000	2,000,000	7
						8
03/07/06	03/10/16	03/10/06	03/10/16	50,000,000	2,875,000	9
						10
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	11
						12
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	532,414	13
						14
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	106,528	15
						16
07/31/07	07/31/27			851,494		17
						18
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,650,000	19
						20
						21
				332,571,494	14,193,942	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				332,571,494	14,193,942	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223 - NONE		
4			
5	ACCOUNT 224		
6	UNSECURED DEBENTURES:		
7	5.00% SERIES DUE IN 2014	40,000,000	410,000
8			379,200 D
9	5.75% SERIES DUE IN 2016	50,000,000	390,200
10			30,000 D
11	6.20% SERIES DUE IN 2036	65,000,000	653,550
12			367,900 D
13	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	705,545
14			
15	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	1,029,608
16			
17	TEPPCO-Todhunter Cavern Gas Storage	851,494	
18			
19	4.650% SERIES DUE IN 2019	100,000,000	756,468
20			374,000 D
21			
22	SUBTOTAL ACCOUNT 224	332,571,494	5,096,471
23			
24			
25			
26	See footnote		
27			
28			
29			
30			
31			
32			
33	TOTAL	332,571,494	5,096,471

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
12/06/04	12/15/14	12/06/04	12/15/14	40,000,000	2,000,000	7
						8
03/07/06	03/10/16	03/10/06	03/10/16	50,000,000	2,875,000	9
						10
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	11
						12
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	540,259	13
						14
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	75,672	15
						16
07/31/07	07/31/27			851,494		17
						18
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,650,000	19
						20
						21
				332,571,494	14,170,931	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				332,571,494	14,170,931	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2015	End of 2014/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223		
4	Intercompany Moneypool Notes Payable-Long Term, .39%	25,000,000	
5			
6	SUBTOTAL ACCOUNT 222 & 223	25,000,000	
7			
8	ACCOUNT 224		
9	UNSECURED DEBENTURES:		
10	5.00% SERIES DUE IN 2014	40,000,000	410,000
11			379,200 D
12	5.75% SERIES DUE IN 2016	50,000,000	390,200
13			30,000 D
14	6.20% SERIES DUE IN 2036	65,000,000	653,550
15			367,900 D
16	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	705,545
17			
18	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	1,029,608
19			
20	TEPPCO-Todhunter Cavern Gas Storage	851,494	
21			
22	4.650% SERIES DUE IN 2019	100,000,000	756,468
23			374,000 D
24			
25	SUBTOTAL ACCOUNT 224	332,571,494	5,096,471
26			
27			
28			
29	See footnote		
30			
31			
32			
33	TOTAL	357,571,494	5,096,471

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2015	End of 2014/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
				25,000,000		4
						5
				25,000,000		6
						7
						8
						9
12/06/04	12/15/14	12/06/04	12/15/14		1,911,111	10
						11
03/07/06	03/10/16	03/10/06	03/10/16	50,000,000	2,875,000	12
						13
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	14
						15
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	527,006	16
						17
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	79,589	18
						19
07/31/07	07/31/27			851,494		20
						21
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,650,000	22
						23
						24
				292,571,494	14,072,706	25
						26
						27
						28
						29
						30
						31
						32
				317,571,494	14,072,706	33

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2016	Year/Period of Report End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223		
4	Intercompany Moneypool Notes Payable-Long Term, .39%	25,000,000	
5			
6	SUBTOTAL ACCOUNT 222 & 223	25,000,000	
7			
8	ACCOUNT 224		
9	UNSECURED DEBENTURES:		
10			
11			
12	5.75% SERIES DUE IN 2016	50,000,000	390,200
13			30,000 D
14	6.20% SERIES DUE IN 2036	65,000,000	653,550
15			367,900 D
16	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	705,545
17			
18	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	1,029,608
19			
20	TEPPCO-Todhunter Cavern Gas Storage	851,494	
21			
22	4.650% SERIES DUE IN 2019	100,000,000	756,468
23			374,000 D
24			
25	SUBTOTAL ACCOUNT 224	292,571,494	4,307,271
26			
27			
28			
29			
30			
31	See footnote		
32			
33	TOTAL	317,571,494	4,307,271

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/13/2016	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No
						1
						2
						3
				25,000,000		4
						5
				25,000,000		6
						7
						8
						9
						10
						11
03/07/06	03/10/16	03/10/06	03/10/16	50,000,000	2,875,000	12
						13
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	14
						15
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	539,302	16
						17
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	74,263	18
						19
07/31/07	03/31/15					20
						21
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,650,000	22
						23
						24
				291,720,000	12,168,565	25
						26
						27
						28
						29
						30
						31
						32
				316,720,000	12,168,565	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2			
3	ACCOUNTS 222 & 223		
4	Intercompany Moneypool Notes Payable-Long Term, .986%	25,000,000	
5			
6	SUBTOTAL ACCOUNT 222 & 223	25,000,000	
7			
8	ACCOUNT 224		
9	UNSECURED DEBENTURES:		
10			
11	5.75% SERIES DUE IN 2016	50,000,000	390,200
12			30,000 D
13	6.20% SERIES DUE IN 2036	65,000,000	653,550
14			367,900 D
15	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	705,545
16			
17	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	1,029,608
18			
19	3.42% SERIES DUE IN 2026	45,000,000	220,191
20			
21	4.45% SERIES DUE IN 2046	50,000,000	247,535
22			
23	4.650% SERIES DUE IN 2019	100,000,000	756,468
24			374,000 D
25			
26	SUBTOTAL ACCOUNT 224	386,720,000	4,774,997
27			
28			
29			
30			
31			
32	See footnote		
33	TOTAL	411,720,000	4,774,997

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
12/15/14	01/30/20			25,000,000		4
						5
				25,000,000		6
						7
						8
						9
						10
03/07/06	03/10/16	03/10/06	03/10/16		551,042	11
						12
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	13
						14
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	630,962	15
						16
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	175,807	17
						18
01/05/16	01/15/26	01/05/16	01/15/26	45,000,000	1,521,900	19
						20
01/05/16	01/15/46	01/05/16	01/15/46	50,000,000	2,200,278	21
						22
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,650,000	23
						24
						25
				336,720,000	13,759,989	26
						27
						28
						29
						30
						31
						32
				361,720,000	13,759,989	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2	ACCOUNTS 222 & 223		
3	Intercompany Moneypool Notes Payable-Long Term .986%	25,000,000	
4	SUBTOTAL ACCOUNT 222 & 223	25,000,000	
5			
6	ACCOUNT 224		
7	UNSECURED DEBENTURES:		
8	6.20% SERIES DUE IN 2036	65,000,000	653,550
9			367,900 D
10	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	705,545
11			
12	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	1,029,608
13			
14	3.42% SERIES DUE IN 2026	45,000,000	220,191
15			
16	4.45% SERIES DUE IN 2046	50,000,000	247,535
17			
18	4.65% SERIES DUE IN 2019	100,000,000	756,468
19			374,000 D
20	3.35% SERIES DUE IN 2029	30,000,000	124,475
21			
22	4.11% SERIES DUE IN 2047	30,000,000	124,475
23			
24	4.26% SERIES DUE IN 2057	30,000,000	124,475
25			
26	SUBTOTAL ACCOUNT 224	426,720,000	4,726,222
27			
28	See footnote		
29			
30			
31			
32			
33	TOTAL	451,720,000	4,728,222

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/12/2018	End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/15/14	03/16/22			25,000,000	453,674	3
				25,000,000	453,674	4
						5
						6
						7
03/07/06	03/10/36	03/10/06	03/10/36	65,000,000	4,030,000	8
						9
12/11/08	08/01/27	12/11/08	08/01/27	50,000,000	770,352	10
						11
11/24/10	08/01/27	11/24/10	08/01/27	26,720,000	290,791	12
						13
01/05/16	01/15/26	01/05/16	01/15/26	45,000,000	1,539,000	14
						15
01/05/16	01/15/46	01/05/16	01/15/46	50,000,000	2,225,000	16
						17
09/22/09	10/01/19	09/22/09	10/01/19	100,000,000	4,650,000	18
						19
09/07/17	09/15/29	09/07/17	09/15/29	30,000,000	318,250	20
						21
09/07/17	09/15/47	09/07/17	09/15/47	30,000,000	390,450	22
						23
09/07/17	09/15/57	09/07/17	09/15/57	30,000,000	404,700	24
						25
				426,720,000	14,618,543	26
						27
						28
						29
						30
						31
						32
				451,720,000	15,072,217	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - NONE		
2	ACCOUNTS 222 & 223		
3	Intercompany Moneypool Notes Payable-Long Term, 2.794%	25,000,000	
4	SUBTOTAL ACCOUNT 222 & 223	25,000,000	
5			
6	ACCOUNT 224		
7	UNSECURED DEBENTURES:		
8	6.20% SERIES DUE IN 2036	65,000,000	653,550
9			367,900 D
10	2008 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	50,000,000	705,545
11			
12	2010 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027	26,720,000	1,029,608
13			
14	3.42% SERIES DUE IN 2026	45,000,000	220,191
15			
16	4.45% SERIES DUE IN 2046	50,000,000	247,535
17			
18	4.65% SERIES DUE IN 2019	100,000,000	756,468
19			374,000 D
20	3.35% SERIES DUE IN 2029	30,000,000	124,475
21			
22	4.11% SERIES DUE IN 2047	30,000,000	124,475
23			
24	4.26% SERIES DUE IN 2057	30,000,000	124,475
25			
26	4.01% SERIES DUE IN 2023	25,000,000	111,522
27			
28	4.18% SERIES DUE IN 2028	40,000,000	156,522
29			
30	4.62% SERIES DUE IN 2048	35,000,000	141,522
31			
32	SUBTOTAL ACCOUNT 224	526,720,000	5,137,788
33	TOTAL	551,720,000	5,137,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc	(1) [X] An Original (2) [ ] A Resubmission	04/12/2019	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/15/2014	03/16/2023			25,000,000	565,390	3
				25,000,000	565,390	4
						5
						6
						7
03/07/2006	03/10/2036	03/10/2006	03/10/2036	65,000,000	4,030,000	8
						9
12/11/2008	08/01/2027	12/11/2008	08/01/2027	50,000,000	1,320,995	10
						11
11/24/2010	08/01/2027	11/24/2010	08/01/2027	26,720,000	308,261	12
						13
01/05/2016	01/15/2026	01/05/2016	01/15/2026	45,000,000	1,539,000	14
						15
01/05/2016	01/15/2046	01/05/2016	01/15/2046	50,000,000	2,225,000	16
						17
09/22/2009	10/01/2019	09/22/2009	10/01/2019	100,000,000	4,650,000	18
						19
09/07/2017	09/15/2029	09/07/2017	09/15/2029	30,000,000	1,005,000	20
						21
09/07/2017	09/15/2047	09/07/2017	09/15/2047	30,000,000	1,233,000	22
						23
09/07/2017	09/15/2057	09/07/2017	09/15/2057	30,000,000	1,278,000	24
						25
10/03/2018	10/15/2023	10/03/2018	10/15/2023	25,000,000	245,056	26
						27
10/03/2018	10/15/2028	10/03/2018	10/15/2028	40,000,000	408,711	28
						29
12/12/2018	12/15/2048	12/12/2018	12/15/2048	35,000,000	85,342	30
						31
				526,720,000	18,328,365	32
				551,720,000	18,894,755	33

AG-DR-01-076

REQUEST:

With regard to the Company's forecasted Completed Construction Not Classified amounts provided in STAFF-DR-01-054_Attachment_-_KPSC_Elec_SFRs_-_2019.xls, provide details of the following balances by individual FERC account or in the greatest level of detail indicating the specific types of Completed Construction Not Classified plant:

(a) Balance at 11/30/2019:

1.	Steam Production	$18,783,137
2.	Other Production	$12,589,160
3.	Transmission	$2,402,028
4.	Distribution	$19,154,592
5.	General	$9,120,817

(b) Balance at 4/1/2020:

1.	Steam Production	$33,926,886
2.	Other Production	$18,659,133
3.	Transmission	$5,768,928
4.	Distribution	$66,230,170
5.	General	$19,976,240

(c) Balance at 3/31/2021:

1.	Steam Production	$73,388,962

2.	Other Production	$22,240,536
3.	Transmission	$16,009,088
4.	Distribution	$133,636,875
5.	General	$30,797,988

Provide in executable electronic (Excel) format.

RESPONSE:

Please see AG-DR-01-076 Attachment.

PERSON RESPONSIBLE: Christopher M. Jacobi

DE Kentucky Electric
Completed Construction Not Classfied
$000s

	11/30/2019	4/1/2020	3/31/2021
B1 - Fossil Env Compliance Air	17,320	17,329	17,329
B4 - Fossil Ash Basin Initiative	-	10,945	32,684
BA - Fossil Steam Plants	3,623	8,775	30,211
BD - Environmental Fossil Plants	341	1,348	3,165
CC - Capital Challenge	(2,500)	(5,000)	(10,000)
Steam Production Total	18,783	33,397	73,389
BG - Other Production Plant (Woodsdale Station)	12,589	18,659	22,241
Other Production Total	12,589	18,659	22,241
FF - Transmission Stations	742	2,638	6,825
GG - Transmission Lines	1,660	3,131	9,184
Transmission Total	2,402	5,769	16,009
GG - Transmission Lines	-	550	3,034
HB - Distribution Substation	4,598	8,636	39,067
HW - Distribution Highway Jobs	1,359	1,952	4,330
IK - Distrib Lines OH/UG (Line Ext)	9,327	47,456	72,142
IO - Distribution Improvements	3,294	6,280	10,858
OU - Other Utility	-	140	1,627
TB - Equipment & Tools	72	128	282
TD - Other - Office Equipment	202	436	919
VS - Intangible Plant - Software	303	653	1,378
Distribution Total	19,155	66,230	133,637
QQ - Meters, Panel & Panel Troughs	42	76	181
RR - Communication	4,773	8,725	17,662
VS - Intangible Plant - Software	703	2,013	3,522
IO - Distribution Improvements	156	253	524
TD - Office Equipment	3,446	8,909	8,909
General Total	9,121	19,976	30,798

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-077

REQUEST:

With regard to the Company's forecasted Completed Construction Not Classified amounts provided in STAFF-DR-01-054_Attachment_-_KPSC_Elec_SFRs_-_2019.xls, provide all calculations showing the derivation of the "13 Month Average" balances for each line item. Provide in executable electronic (Excel) format.

RESPONSE:

Please see AG-DR-01-077 Attachment.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky Electric
Calculation of 13 Month Average
Completed Construction Not Classified

	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	13 mo Avg
Steam Production Plant	33,396,898	33,939,741	54,680,223	70,272,304	71,989,866	71,990,593	70,741,321	70,742,048	70,742,775	74,390,814	74,473,673	74,556,313	73,388,962	65,023,502
Other Production Plant	18,659,133	18,659,133	18,659,133	20,091,718	20,091,718	20,091,718	20,150,941	20,150,941	20,150,941	20,177,404	20,177,404	20,177,404	22,240,537	19,959,856
Transmission Plant	5,768,928	6,116,688	6,625,812	9,096,640	9,171,600	9,176,558	12,233,058	12,259,676	12,266,167	15,159,294	15,234,093	15,308,695	16,009,088	11,109,715
Distribution Plant	66,230,170	69,387,484	72,392,324	76,799,323	79,708,590	82,350,738	87,215,260	89,773,904	92,420,846	124,127,517	127,008,809	129,889,967	133,636,875	94,687,831
General Plant	19,976,240	20,008,468	20,040,701	22,867,216	22,899,449	22,931,683	25,539,109	25,571,344	25,603,576	28,690,823	28,719,613	28,748,403	30,797,987	24,799,586

AG-DR-01-078

REQUEST:

Regarding the Company's class cost of service study as it relates to the meter allocation factor shown in Tab: "WP FR-16(7)(v) Meters" of the Company's CCOSS model, the meter costs are derived from the "Input Data" tab. In these regards, provide all source documents utilized to develop the "meter" costs by class for this rate case as well the corresponding meter costs developed in the same tab in the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

Please see AG-DR-01-078 Attachment 1 for the meter costs in the current case.

Please see AG-DR-01-078 Attachment 2 for the meter costs in Case No. 2017-00321.

PERSON RESPONSIBLE: James E. Ziolkowski

2019-00271

AG-DR-01-078

ATTACHMENT 1

IS BEING FILED ON CD DUE TO SIZE

Rate	Meter		CT		PT		Total Cost	%
	Count	Cost	Count	Cost	Count	Cost		
	781	$150,571	197	$14,841	3	$2,121	$167,533	2.64%
DP	11	$5,329	26	$2,784	5	$2,540	$10,654	0.17%
DS	14,051	$2,398,403	4,097	$265,981	65	$32,315	$2,696,699	42.46%
DT	232	$82,060	271	$22,723	33	$20,635	$125,418	1.97%
EH	105	$18,253	67	$4,404			$22,657	0.36%
RS	131,839	$3,285,527	223	$14,397			$3,299,924	51.96%
SP	17	$2,330	6	$385			$2,715	0.04%
TT	19	$3,619	32	$5,946	12	$6,483	$16,048	0.25%
WS	11	$1,642	24	$1,554	10	$5,791	$8,987	0.14%
Total	147,066	$5,947,735	4,943	$333,015	128	69,886	$6,350,637	

AG-DR-01-079

REQUEST:

Regarding the Company's class cost of service study as it relates to the meter allocation factor shown in Tab: "WP FR-16(7)(v) Meters" of the Company's CCOSS model, the meter costs are derived from the "Input Data" tab. In these regards, explain and quantify the dramatic differences in meter costs for several classes as well as in total shown in the Company's current cost of service model to those amounts provided in the same tabs from the 2017 General Rate Case (Case No. 2017-00321):

	Meter Cost		
	Case No. 2017-00321	Case No. 2019-00271	Change
Residential	\$3,299,927	\$12,782,441	\$9,482,514
Dist Secondary – DS	\$2,696,699	\$2,892,747	\$196,048
Dist Secondary – GS-FL	-	-	-
Dist Secondary – EH	\$22,657	\$22,093	(\$564)
Dist Secondary – SP	\$2,715	\$3,451	\$736
Dist Secondary - DT	\$125,418	\$102,877	(\$22,541)
Dist Primary – DT	-	-	-
Dist Primary – DP	\$10,654	\$3,805	(\$6,849)
Transmission	\$16,048	\$3,619	(\$12,429)
Lighting	-	-	-
Other	\$176,520	\$2,208	(\$174,312)
TOTAL	\$6,350,638	\$15,813,241	\$9,462,603

Provide all analyses and quantifications in executable electronic (Excel) format.

RESPONSE:

Please see the response to AG-DR-01-078. The meter costs that appear on the Inputs tab were obtained from the Company's meter department. They are the current costs of new meters of various sizes for the rate groups based on the stock number of the installed meters for each account. The meter costs analysis in the 2017 case was performed by the meter department. Additional data is not available.

The main driver of the large increase in meter costs since the last rate case is the installation of new smart meters for the residential class. The new meters are digital and are more expensive than the old traditional meters.

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-080

REQUEST:

With regard to the Company's forecasted Customer Accounting Expense of $5,122,347 (as per the CCOSS), please provide a detailed breakdown of this expense by category.

RESPONSE:

Breakdown by category is as follows:

Labor	2,941,772
Other Contracts	831,460
IT Costs	499,891
Postage & Freight	275,281
Overhead Allocations	434,239
All Other	139,704
Total	5,122,347

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-081

REQUEST:

With regard to the Company's forecasted Customer Accounting Expense of $5,122,347 (as per the CCOSS), please explain the 53% increase is this expense account from the Company's 2017 General Rate Case of $3,335,314.

RESPONSE:

In the Company's 2017 General Rate Case, a credit related to Loss on Sale of Accounts Receivable was included in Customer Accounting Expenses in account 903250. In the instant case, these amounts are included in the 426 accounts.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-082

REQUEST:

With regard to the Company's forecasted Customer Accounting Expense of $5,122,347 (as per the CCOSS), the Residential class is allocated 82% of the total Company amount in this case while the Residential class was only allocated 53% of the total Company amount in the Company's 2017 General Rate Case. Please provide a detailed explanation of this dramatic increase in the relative percentage allocation to the Residential class for this account.

RESPONSE:

Instead of allocating Customer Accounting Expense on customer count, the COSS allocates this expense to the rate classes based on meter-cost weighted customer count. This methodology results in fewer dollars being allocated to the residential class than would occur if the expense was allocated on actual customer count.

As noted in AG-DR-01-079, meter costs for some classes increased since the 2017 rate case. This resulted in the increase in allocation to the residential class in the current case. The calculations of the weighted customer counts appear in the "Meters" tabs in the 2019 and 2017 COSS.

PERSON RESPONSIBLE: James E. Ziolkowski

AG-DR-01-083

REQUEST:

Regarding the Company's class cost of service study as it relates to the services allocation factor shown in Tab: "WP FR-16(7)(v) Wtd services" of the Company's CCOSS model, please explain why the class services "weighting" factors change from those used in the Company's 2017 General Rate Case (Case No. 2017-00321) as shown below:

Services Weighting Factor	Case No. 2017-00321	Case No. 2019-00271
Dist Secondary – EH	7	4
Dist Secondary – DT	7	6
Dist Primary – DT	7	6
Dist Primary – DP	7	6
Transmission	7	6

Provide all analyses and quantifications in executable electronic (Excel) format.

RESPONSE:

Please see the tabs "Serv cost wgt" and "Wtd Services" in the cost of service studies.

The weighting factors are calculated in the "Serv cost wgt" tabs. The weighting factors are calculated as the ratio of the cost of a certain size service to the cost of the 25 kVA service. By definition, the weighting factor for the 25 kVA service will be 1. Each of the weighting factors in the 2019 COSS are the same as the 2017 COSS except for the 300 kVA service. The 300 kVA weighting factor decreased from 7 to 6 in the 2019 COSS.

On the "Wtd services" tab, the weighting factor for Rate EH decreased from 7 in the 2017 COSS to 4 in the 2019 COSS. This occurred because the average demand per EH customer for the peak month decreased between the 2017 and 2019 studies from 22,213 kW to 10,653 kW.

For the other rate classes, the weighting factor decreased from 7 to 6 for the reason as described in the second paragraph above.

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-084

REQUEST:

Provide a detailed explanation of why Primary Overhead Lines Operations expenses have increased by 43.8% ($6,300,659 vs. $4,382,116) and 30.7% for Secondary Overhead expenses ($2,573,508 vs. $1,968,777) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

The principal factor contributing to the higher cost in the forecasted test period in this case compared to the 2017 General Rate Case is the increased cost of vegetation management.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-085

REQUEST:

Provide a detailed explanation of why Primary Underground Lines Operations expenses have increased by 23.5% ($883,360 vs. $715,168) and 23.5% for Secondary Underground expenses ($180,929 vs. $146.480) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

The principal factor contributing to the increase in Primary Underground Lines Operations expenses and Secondary Underground expenses since the Company's 2017 General Rate Case is an increase in cable locate expenses in account 584.

PERSON RESPONSIBLE: Christopher M. Jacobi

AG-DR-01-086

REQUEST:

Provide a detailed explanation of why Transformers Operations expenses have increased by 218.4% ($359,568 vs. $112,939) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

The increase in Transformers Operations expenses since the Company's 2017 General Rate Case is due to an increase in environmental maintenance expenses in account 595.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-087

REQUEST:

Provide a detailed explanation of why Distribution Load Dispatch Operations expenses have increased by 23.2% ($578,857 vs. $469,682) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

The increase in Distribution Load Dispatch Operations expenses since the Company's 2017 General Rate Case is due to an increase in labor costs at the distribution control center.

PERSON RESPONSIBLE: Christopher M. Jacobi

AG-DR-01-088

REQUEST:

Provide a detailed explanation of why Meters Operations expenses have increased by 195.0% ($1,076,097 vs. $364,718) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

The primary factor contributing to the increase in Meters Operations expenses since the Company's 2017 General Rate Case is an increase in meter services costs budgeted to account 586 in the current case.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-089

REQUEST:

Provide a detailed explanation of what Other Distribution Operations expenses is, and why this expense has decreased by 46.0% ($722,843 vs. $1,339,434) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

In the current case Other Distribution Operations expenses include supervision and engineering costs related to distribution operations and maintenance. In the Company's 2017 General Rate Case, Other Distribution Operations expenses included supervision and engineering costs related to distribution operations as well as expenses related to customer installations.

The decrease in Other Distribution Operations expenses since the Company's 2017 General Rate Case is primarily due to customer installations costs being included in this total in the prior case and not in the current case. Partially offsetting this impact is an increase in supervision and engineering costs.

PERSON RESPONSIBLE: Christopher Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-090

REQUEST:

Provide a detailed explanation of what Distribution Operations Miscellaneous Expense Adjustment is, and why this expense has decreased by 39.1% ($2,227,726 vs. $3,656,514) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

Distribution Operations Miscellaneous Expense is made up of expenses in account 588, including costs incurred for implementing grid improvement workstreams including hardening and resiliency, self-optimizing grid, and targeted undergrounding. This expense has decreased since the Company's 2017 General Rate Case due to lower costs related to capacity hardening and resiliency work and lower expense for certain transmission related improvements.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-091

REQUEST:

Provide a detailed explanation of why Customer Accounting Expenses have increased by 53.6% ($5,122,347 vs. $3,335,314) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

See response to AG-DR-01-081.

PERSON RESPONSIBLE: Christopher M. Jacobi

AG-DR-01-092

REQUEST:

Provide a detailed explanation of what the Uncollectible Expense Adjustment ($2,199,572) is.

RESPONSE:

Please see the direct testimony of Sarah. E. Lawler, pages 12-13, for a description of the uncollectible expense adjustment, Schedule D-2.31.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-093

REQUEST:

Provide a detailed explanation of why Customer Service and Information expenses has decreased by 44.1% ($604,867 vs. $1,081,198) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

The decrease is due to lower labor and contract costs in the current case compared to the 2017 General Rate Case.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-094

REQUEST:

Provide a detailed explanation of why Sales expenses have increased by 122.4% ($1,497,140 vs. $673,076) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

The increase is due to increases in expenses for labor and consultants in the forecasted test period in the current case as compared to the test year in the Company's 2017 General Rate Case.

PERSON RESPONSIBLE: Christopher M. Jacobi

AG-DR-01-095

REQUEST:

Provide a detailed explanation of why Administrative & General Excluding Regulatory Commission Expenses have increased by 73.4% ($31,532,897 vs. $18,184,699) since the Company's 2017 General Rate Case (Case No. 2017-00321).

RESPONSE:

Schedule C-2 shows that Administrative & General Expense decreased to $16,041,613 in the current case. The Administrative & General Expense amount of $31,532,897 that appears in the Cost of Service Study (COSS) inadvertently included $15,491,284 of regulatory asset amortizations. The $15,491,284 can be seen on Line 21 of Schedule C-2 as Other expenses. Ideally, the $15,491,284 should be shown on a separate line in the COSS.

PERSON RESPONSIBLE: Christopher M. Jacobi
Jim Ziolkowski

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-096

REQUEST:

Please provide the current number of Duke Kentucky jurisdictional customers (accounts) by rate schedule for each zip code within the Company's Kentucky service area. Note: street lighting accounts may be excluded from this data set, as well as those customers served at transmission or sub-transmission voltage levels. For those rate schedules that have both primary and secondary voltage customers, please separate between primary and secondary. Provide in executable electronic (Excel) format.

RESPONSE:

Please see AG-DR-01-096 Attachment.

PERSON RESPONSIBLE: Jeff L. Kern

Duke Energy Kentucky
Number of Accounts by Zip Code
As of October 18, 2019

Zip Code	Rate RS	Rate DS Primary	Rate DS Secondary	Rate DT Primary	Rate DT Secondary	Rate EH	Rate DP	Rate SP
41001	5,690	-	574	1	4	2	-	1
41005	4,151	1	423	-	1	3	-	-
41007	131	-	12	-	-	-	-	-
41011	12,345	-	1,380	1	10	2	1	2
41014	3,511	-	189	1	4	-	-	-
41015	8,870	-	601	1	4	5	1	-
41016	2,681	-	166	1	-	-	-	-
41017	16,261	-	1,351	3	12	4	1	-
41018	8,979	-	961	3	15	2	-	-
41030	1,799	-	179	-	-	1	-	1
41031	-	-	1	-	-	-	-	-
41033	118	-	15	-	-	1	-	1
41035	1,442	1	288	1	2	2	1	1
41041	1	-	-	-	-	-	-	-
41042	16,658	1	2,590	17	49	5	3	1
41046	1	-	-	-	-	-	-	-
41047	1	-	-	-	-	-	-	-
41048	1,822	-	447	2	13	1	2	1
41051	4,171	-	331	-	5	4	-	-
41052	1	-	-	-	-	-	-	-
41059	1,106	-	113	-	-	1	-	-
41063	501	-	36	-	-	1	-	-
41071	10,176	-	1,119	-	6	2	-	2
41073	3,027	-	216	-	-	-	-	1
41074	2,628	-	178	1	1	-	-	1
41075	7,393	-	401	3	3	2	2	1
41076	7,852	-	611	4	4	4	-	-
41080	395	-	35	-	1	-	-	-
41084	27	-	8	-	-	-	-	-
41085	380	-	50	-	-	1	-	-
41091	3,977	-	236	-	2	1	-	-
41092	157	-	25	-	-	-	-	-
41094	4,771	-	542	1	7	1	2	-
41097	-	-	2	-	-	-	-	-
Total	131,023	3	13,080	40	143	45	13	13

REQUEST:

Refer to the Direct Testimony of Amy B. Spiller ("Spiller Direct"), page 20, wherein she discusses the recent completion of the Woodsdale dual-fuel system. Other than satisfying PJM's performance capacity requirements, discuss the potential benefits for ratepayers of this modification, if any.

RESPONSE:

In addition to addressing the PJM capacity performance requirement, the option of backup fuel oil at Woodsdale Station has further potential benefits for the Duke Energy Kentucky customers such as (1) the ability to produce energy from the Woodsdale units when natural gas is not available or uncertain such as during an Operational Flow Order (OFO), (2) the ability to manage natural gas burn during time periods of an OFO restriction on the pipeline, (3) the ability to operate the units on fuel oil in the event that there are natural gas pressure issues on the pipeline, and (4) the ability to capture additional value from the Woodsdale units when the price of natural gas is greater than the price of fuel oil.

(1) <u>Ability to produce energy from the Woodsdale units when natural gas is not available or uncertain such as during an Operational Flow Order (OFO)</u>: During times when natural gas is unavailable, the Woodsdale units remain available to the energy markets and are offered on fuel oil, allowing them to continue to be provide value for the customer. In addition, during early morning winter hours on high

demand days, the potential availability of natural gas during the pipeline post cycle is uncertain, such as when PJM commits a Woodsdale unit after 7:00 PM and before 10:00 AM the next day (the end of the gas day) in the Real-Time market. Prior to the addition of fuel oil, during such times the Company may have been forced to offer the units as unavailable. With the addition of backup fuel oil, the units to be offered with a higher level of confidence during these times with the knowledge that, if natural gas isn't available, the units can still be offered to PJM using fuel oil.

(2) <u>Ability to manage natural gas burn during time periods of an OFO restriction on the pipeline</u>: The availability of fuel oil allows better management of natural gas due to the additional option of switching to fuel oil to manage the OFO. For example, if over burning natural gas above the OFO limit would cause a penalty greater than the cost of fuel oil, it would be more economic to switch the units to fuel oil to avoid the OFO penalty.

(3) <u>Ability to operate the units on fuel oil in the event that there are natural gas pressure issues on the pipeline</u>: TETCO pipeline, serving Woodsdale, has initiated a reduction in gas pressure on its system to perform inquiry inspections that could impact the flow of natural gas to the Woodsdale units during the Winter of 2019-2020. The additional option of fuel oil will help manage this situation for the Duke Energy Kentucky customer.

(4) <u>Ability to capture additional value from the Woodsdale units when the price of natural gas is greater than the price of fuel oil</u>: When the price of natural gas is

greater than fuel oil, the units can be run on fuel oil, allowing for additional value captured for the customer.

PERSON RESPONSIBLE: John Verderame

AG-DR-01-098

REQUEST:

Refer to Spiller Direct, page 21, wherein she discusses "smart city planning." For each technology item cited, discuss which, if any, will be placed into ratebase, and provide the tariff sheets, if any, in which these technologies are referenced along with any prices that are discussed.

RESPONSE:

None of the items listed on page 21 of Amy Spiller's Direct Testimony are included in rate base. Currently, the only tariff sheet that references smart technology is Rate LED. Otherwise, these technologies will be served under whichever rate they qualify.

PERSON RESPONSIBLE: Sarah E. Lawler – regarding rate base
Jeff L. Kern – regarding tariffs

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-099

REQUEST:

Provide a list of all transmission projects that DEK is planning in its service territory in the next five (5) years. Any response should indicate whether DEK expects the project(s) to be considered "Supplemental" under PJM governing documents.

RESPONSE:

Objection. This request is overbroad, unduly burdensome, in terms of time, seeks information beyond the test period, seeks information that does not exist in the form requested, calls for speculation and seeks information that is not relevant or likely to lead to the discovery of relevant or admissible evidence. Without waiving said objection, and to the extent discoverable, the following transmission projects are planned to be in service during the test period in this case:

Funding Project Description	PJM Supplemental
Kentucky Ground Line Treatment Inspection Pole Replacement	No
Kentucky Transmission Relocation including DOT	No
Aero Transmission Supply	Yes
Villa Bus 1 Switchgear Replacement	No
Buff-Kent-Villa Circuit Breaker & Relay Replacement	No
Villa TB2 and Bus 2 Switchgear Replacement	Yes
Buffington Distribution Reliability Upgrade	Yes
Hebron XTR Relay Replacement	No
Constance Bus 1 Switchgear and CB Replacement	Yes
Villa 69 kV Ring Bus	Yes
Buffington Reconfigure Bus 4_5	No
Rebuild Claryville to Decoursey circuit	Yes
Kentucky Found in Field Pole and Line Replacement	No
Kentucky Storm and Auto Restoration - Poles and Line	No

Kentucky Transmission Equipment Failures	No
Vegetation Clearing	No

PERSON RESPONSIBLE: As to objection, Legal
Tim Abbott

AG-DR-01-100

REQUEST:

Refer to MISO's MTEP 19 Market Congestion Planning Study, accessible at the link below,[1] at slide 4. With regard to the Hubble to Batesville 138 kV flowgate, discuss whether this will or does already have any interconnection to the DEOK transmission zone in PJM. If so:

a. Provide a timeline on any potential capital spending associated with the project; and

b. Provide a discussion on potential retail rate ramifications for DEK customers.

RESPONSE:

a. Objection. This request is overbroad and unduly burdensome, irrelevant and seeks information that is not likely to lead to the discovery of any relevant or admissible evidence. Moreover, this request misstates facts and assumes facts not in evidence and thus it is impossible for Duke Energy Kentucky to answer. Duke Energy Kentucky is not a member of MISO and does not participate in MISO planning.

b. None.

PERSON RESPONSIBLE: Legal – a.
William Don Wathen Jr. – b.

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[1] https://cdn.misoenergy.org/20190529%20SSPM2%20Item%2004a%20MTEP19%20MCPS%20Project%20Candidate%20Identification%20overview348438.pdf

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-101

REQUEST:

Provide the DEBS allocation for the customer information system ("CIS") during the test period and through the end of calendar year 2022.

RESPONSE:

The DEBS Allocations for the customer Information System (CIS) is based on the number of Customers. The ratios are based on the sum of the applicable domestic firm electric customers (and/or gas customers, where applicable) at the end of a recent month in the preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). These ratios will be determined annually, or when required due to a significant change. See allocation method in the DEBS allocation spreadsheet filed in the Kentucky CAM for the number of Customer allocation percentages.

PERSON RESPONSIBLE: Jeffrey R. Setser

AG-DR-01-102

REQUEST:

Refer to Hunsicker Direct generally. Describe what measures the new CIS system has employed to prevent early obsolescence, and to insure interoperability with other systems.

RESPONSE:

The current CIS used by Duke Energy Kentucky is highly customized and is expensive to keep relevant. The new, SAP meter-to-cash platform is an off-the-shelf product that has been implemented by nearly 800 utilities worldwide, and the Company is leveraging best practices from those other utilities to keep pace with the needs and expectations of customers across the globe. Additionally, since Duke Energy is not the only company leveraging this platform, it is incumbent upon SAP to keep it up-to-date based on the changing needs of customers, and to that end, the system will have periodic updates that will keep it relevant for years to come. Since this system is not customized, accepting the updates will not require major code changes.

PERSON RESPONSIBLE: Retha Hunsicker

AG-DR-01-103

REQUEST:

Refer to Hunsicker Direct generally. Describe what measures DEK or its affiliates will take to obtain customer feedback prior to the final roll-out of billing and payment processes, and the universal bill format.

RESPONSE:

The Customer Connect program team has and will continue to research customer survey data and verbatims to ensure the design of the new system meets the expectations of customers. Additionally, research confirms elements highly important to customers are their billing and payment experience, as well as customer service experience, all of which the Company is improving with the implementation of Customer Connect, as described throughout my testimony.

PERSON RESPONSIBLE: Retha Hunsicker

AG-DR-01-104

REQUEST:

Refer to the Direct Testimony of Melissa B. Abernathy ("Abernathy Direct"), page 7, discussing asbestos removal at Miami Fort 6. Provide a description of the areas from which asbestos is being removed; i.e., is removal occurring throughout the entire Miami Fort Station? If so, provide the total costs being allocated to DEK.

a. Provide the ownership allocation of unit no. 6 in effect at the time Duke Energy sold its final interests in that unit.

RESPONSE:

The Burns & McDonnell Decommissioning Cost Estimate Study, dated March 22, 2017, includes $6,253,000 ($7,816,250 including project indirects or contingency) of asbestos abatement costs at Miami Fort Unit 6. Asbestos is being removed from the Miami Fort Unit 6 building enclosure from roof to basement, and is inclusive of gas ductwork, precipitators, air ducts/fans, air preheaters, boiler, windboxes, power/process piping, pulverizers, and other thermal system insulation locations throughout the unit. Duke Energy's ownership allocation of Miami Fort Unit 6 is 100%.

PERSON RESPONSIBLE: Melissa B. Abernathy

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-105

REQUEST:

Refer to the Direct Testimony of Jeff L. Kern ("Kern Direct"), Attachment JLK-1, p. 15 of 18, Electric Tariff Sheet No. 91.

a. Explain the proposed 70.43% increase for remote reconnections, from the current \$3.45 to \$5.88.

b. Provide a detailed cost breakdown with an explanation for cost items that increased.

c. Provide a list of all attendant costs that decreased.

d. Provide a detailed explanation of all steps involved in making a remote disconnection.

RESPONSE:

a. The Company has revised the method used to calculate the proposed fee for remote reconnections since the last case (Case No. 2017-00321) when the current fee of \$3.45 was approved. See response to STAFF-DR-02-074.

b. The costs included in the calculation of the proposed reconnection fee for remote reconnections are shown in Kern Direct, Attachment JLK-5. The base labor rate used in the calculation increased from \$16.16 to \$16.82. While the cost of Base Occupancy and Shrinkage did not necessarily increase, these items were not included in the calculation from the previous case (Case No. 2017-00321), so contributed to the increase in the proposed rate.

c. The loading factors in total decreased from $17.90 to $13.33.

d. The manual process for making a remote disconnection is as follows. Please note that this does not include the process and cost for the Company associated with a customer being delinquent and necessitating a disconnection, such as mailed notices, text/call notices and time spent by Customer Care Operations taking calls to explain bills or set payment plans.

- Enter Transaction Code
- Enter Date Wanted
- Enter any additional field remarks or notes
- Press Enter to complete order

PERSON RESPONSIBLE: Jeff L. Kern

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-106

REQUEST:

Refer to the Direct Testimony of Lesley G. Quick ("Quick Direct"), generally, and Electric Tariff Sheet No. 91. Provide a justification for adding the $200 equipment tampering penalty, including a summary of historic costs incurred for tampering.

a. Explain whether DEK, to date, has taken legal action against customers or others found to have tampered with DEK equipment.

b. Explain what actions, if any, DEK has taken against individuals or entities who are not customers who were found to have tampered with equipment.

c. Provide the rationale and any cost calculations or projections for charging $200.

d. In the event the Company is unable to collect the $200 charge, explain whether the unrecovered cost would be socialized among the rate base.

RESPONSE:

a. Duke Energy Kentucky has not pursued legal action against customers.

b. Duke Energy Kentucky has not encountered situations where the tampering was attributable to individuals or entities who were not the Company's customers.

c. The fee is not necessarily cost-based as it is intended to be a deterrent to tampering. The Company believes that the penalty of approximately twice the average monthly residential bill will provide a sufficient deterrent to discourage tampering.

d. None of the associated cost will be included in rate base.

PERSON RESPONSIBLE: Lesley G. Quick – a. through c.
Sarah E. Lawler – d.

AG-DR-01-107

REQUEST:

Refer to Quick Direct, pages 8–13, regarding the fee-free transaction proposal.

a. Explain whether the cost of fees on credit and debit card transactions was included in the Company's cost-of service study.

b. Explain whether DEK would continue to utilize the third-party payment vendor, SpeedPay, to process credit card, debit card, and electronic check payments.

RESPONSE:

a. The cost for credit card fees under the Company's current proposal to socialize these costs has been included as a proforma adjustment on Schedule D-2.30. The fees also appear on page 8 of 18, line 55, of the cost of service study, FR-16(7)(v)-1.

b. Yes. Duke Energy Kentucky will continue to utilize the third-party payment vendor, SpeedPay for credit card, debit card and electronic check payments.

PERSON RESPONSIBLE: Sarah E. Lawler/Jim Ziolkowski – a.
Lesley G. Quick – b.

REQUEST:

Refer to the Direct Testimony of Zachary Kuznar, PhD ("Kuznar Direct"), generally, regarding how the proposed battery project will provide ancillary services to PJM.

a. Provide a description of PJM's ancillary market, how it works, the number of participants, and how each participant is reimbursed.

RESPONSE:

PJM describes the ancillary services markets at the following location: https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx

In addition, PJM describes the ancillary services markets in more detail in Manual 11, Energy & Ancillary Services Market Operations, starting on page 63:

https://www.pjm.com/-/media/documents/manuals/m11.ashx

A battery resource would be capable of supplying the following ancillary services to the PJM market; Regulation and Frequency Response Service Reserves (PJM Billing Line Item 2340), Synchronized Reserves (PJM Billing Line Item 2360), and Day-Ahead Scheduling Reserves (PJM Billing Line Item 2365). In the following description, Regulation and Frequency Response Service Reserves is referred to as "Regulation" and Synchronized Reserves is a subset of "Reserves".

Ancillary services help balance the transmission system as it moves electricity from generating sources to retail consumers. Throughout the day, PJM operates markets to procure two important ancillary services: regulation and reserves. Balancing the system means matching supply and demand while maintaining a system frequency of 60 Hertz. Several factors can impact supply/demand balance and the system frequency, similar to the careful balancing of a scale. Regulation and reserves work together to maintain this balance, but have different roles:

- Regulation is used to control small mismatches between load (the electricity being consumed) and generation (the electricity being produced), adjusting for small tips to either side of the scale.
- Reserves help to recover system balance by making up for generation deficiencies if there is loss of a large generator, resulting in a large tip in the scale.

Any market participants with qualified resources are eligible to participate in these markets and there are at a minimum dozens of participants in PJM's ancillary services markets. Resources selected to provide an ancillary service are reimbursed based on the market clearing price at that time along with how effective they were at providing the ancillary service they were selected for.

The battery storage system will provide mainly frequency regulation in the PJM market. Duke Energy Kentucky currently provides regulation reserves from the Woodsdale units, but can only be provided during times when the units are on-line. Regulation service is a critical service provided to PJM and paid for by all load serving entities in PJM. This battery will also be used to provide renewable integration as it is located at an existing Duke Energy Kentucky solar farm. Duke Energy Kentucky will use this project to test solar smoothing and shifting applications that may become increasingly important as more intermittent generation resources are added to the grid.

In addition, please refer to the response to STAFF-DR-02-159 for more information.

PERSON RESPONSIBLE: Zachary Kuznar
John Verderame

PUBLIC AG-DR-01-109
(As to Attachment only)

REQUEST:

Refer to Kuznar Direct, generally.

a. Describe the need the deployment of the battery is intended to address.

b. Provide the projected ongoing O&M costs for the battery project, and revenue requirement.

c. Provide all cost-benefit analyses developed with regard to the battery project.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

a. The battery storage system will provide frequency regulation in the PJM market. This service is currently provided by the existing Duke Energy Kentucky Woodsdale CT's, although the amount of regulation provided is limited by the relatively low amount of run time of the units. Regulation is a critical service provided to PJM and paid for by all load serving entities in PJM. This battery will also be used to provide renewable integration as it is located at an existing Duke Energy Kentucky solar farm. Duke Energy Kentucky will use this project to test solar smoothing and shifting applications that may become increasingly important as more intermittent generation resources are added to the grid.

b. See Direct Testimony of Sarah E. Lawler filed in this case (Case No. 2019-00271), beginning on page 15 and continuing to page 16 for projected ongoing O&M costs for the battery project and revenue requirement.

c. See AG-DR-01-109(c) Confidential Attachment for the cost benefit analysis for the Crittenden Storage Project. The attached CBA only includes the benefit provided by PJM's regulation D market for frequency regulation. It does not include what will eventually come out of FERC Order 841 in PJM once it is finalized. FERC issued its Order 841 on February 15, 2018, in which it directed regional grid operators to remove barriers to the participation of electric storage in wholesale markets. By directing the regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage, the Order affirms that storage resources must be compensated for all of the services provided and moves toward leveling the playing field for storage with other energy resources. The confidential attachment will be provided to all parties upon the execution of a Confidentiality Agreement.

PERSON RESPONSIBLE: Zachary Kuznar – a., c.
Sarah E. Lawler – b.

2019-00271

AG-DR-01-109(c) CONFIDENTIAL ATTACHMENT

IS BEING FILED UNDER SEAL

AG-DR-01-110

REQUEST:

Provide all projected cost savings that will result from enhanced reliability of the proposed battery.

RESPONSE:

Please see response to STAFF-DR-02-080 and AG-DR-01-109.

PERSON RESPONSIBLE: Zachary Kuznar

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-111

REQUEST:

Refer to the Kuznar testimony generally, wherein he states the battery project will provide increased reliability at the hospital.

a. Identify the hospital.
b. Identify the nature of the hospital's existing back-up power resources, including any auxiliary generators.

Explain how the proposed project will not result in other ratepayers subsidizing the hospital's overall power costs.

RESPONSE:

Please see response to STAFF-DR-02-80. These questions are no longer applicable as the location of the proposed battery project has changed and it is no longer providing a reliability benefit to the hospital.

PERSON RESPONSIBLE: Zachary Kuznar

AG-DR-01-112

REQUEST:

Refer to the Direct Testimony of Ash M. Norton ("Norton Direct"), generally. Provide a discussion of the distribution facilities DEK will be constructing in order to serve the projected load from the new Amazon hub facilities at Cincinnati-Northern Kentucky International Airport.

RESPONSE:

Construction and initial power is being provided by two (2) 12 kV circuits, Donaldson 45 and Donaldson 47, under construction at this time. The circuits consist of 1.7 miles of underground and 1.4 miles of overhead new primary electric facilities. Circuit power will be provided from two (2) newly installed 22 MVA transformers at the Donaldson Substation.

The new Aero substation will be constructed using four (4)- 22 MVA transformers and twelve (12)- 12kV primary circuits.

PERSON RESPONSIBLE: Ash M. Norton

REQUEST:

Refer to Norton Direct, pages 4–5, wherein he discusses the growth of DEK's distribution systems, and the causes for the growth.

a. At page 5, Mr. Norton states that a primary driver for additional investments in the distribution system will be "localized load growth."

   i. Provide the customer count for each of the past five (5) years, broken down by customer class.

   ii. Provide a breakdown by class of projected localized growth on the specific circuits referred to in order to support development.

RESPONSE:

See response to STAFF-DR-02-105 for more detail on localized load growth. See response to AG-DR-01-119 for details on customers associated with the Donaldson Substation localized growth.

PERSON RESPONSIBLE: Ash M. Norton

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-114

REQUEST:

Refer to Norton Direct, pages 4–5, wherein he states that DEK's forecasted test year delivery system plant in service (13-month average balance ending March 31, 2021) will be $581.657 million, an increase of approximately $90 million since the March 31, 2019 actual balance, and states by way of example that DEK plans to increase distribution substation transformer capacity by approximately 268 kVA. Mr. Norton states that "Investments like these have been necessary to maintain safe, reliable, efficient and economical electric delivery service for our existing customers."

a. Provide the cost estimate for increasing distribution substation transformer capacity by approximately 268 kVA.
   i. Identify all alternatives considered.
   ii. Provide all cost-benefit analyses performed, both for the chosen alternative and as applicable to all other alternatives.
b. State whether the need to increase distribution substation transformer capacity is driven solely by safety, reliability, efficiency, or for the "economical electric delivery service."
c. If the need is safety, provide the specific safety need including any and all industry safety standards mandating the increased spending.

d. If the need is reliability, provide the specific industry reliability need including any and all objective industry safety standards mandating the increased spending.

e. If the need is efficiency, provide the specific efficiency need including any and all objective industry efficiency standards mandating the increased spending.

f. State whether DEK intends to seek a CPCN for the project to increase distribution substation transformer capacity. If not, why not? Identify all other CPCNs the Company intends to seek related to the distribution system.

RESPONSE:

a. The increase is actually 268 MVA, in the vicinity of Aero, not 268 kVA, and is comprised of the following:

   - 150 MVA addition at the Oakbrook substation (cost estimate is $7.2 million)
   - 90 MVA addition at the new Aero substation (cost estimate is $23 million)
   - 28 MVA addition at the existing Donaldson substation (cost estimate is $8.9 million)

   i.

      - **Aero substation**: conceptual alternatives to expand Oakbrook sub and construct a new Aero sub to the east were both considered, but required 138kV line and distribution line extensions, which would have significantly driven up the cost.

- **Donaldson substation expansion:** Additional sites for a new substation (vs Donaldson substation expansion) were considered, but an appropriate site was not available in the timeframe needed to support customer load.
- **Oakbrook substation expansion:** Project is needed to provide secondary Transmission feed to Aero substation, which is standard for substations of this size. Oakbrook is the nearest Transmission substation to Aero so is the lowest cost solution.

ii. The most cost-effective solution that reliably meets customer demand (with least community impact) is selected. Due to limited alternatives based on locations of existing transmission and distribution facilities, conceptual engineering judgement makes the appropriate option transparent.

b. The need is driven by all of these items.

c. If additional capacity is not available, the existing assets will become overloaded, increasing the risk of failure. If Duke Energy personnel or the public is in the vicinity of this equipment when it fails it may create a safety issue.

d. The addition of capacity mitigates equipment overload and associated failures/outages. Also, new substation capacity results in shorter distances between the source (substation) and the customers, resulting in less distribution line exposure which reduces outages. It also provides additional flexibility to reroute power when outages occur. Secondary transmission feeds such as Oakbrook provide a more reliable source for large substations such as Aero.

e. Efficiency is improved by reduced line losses. Increasing substation capacity near the customer load allows for shorter distribution lines from the source (substation) to the customers. Higher voltage transmission lines (with lower line losses) bring the power closer to the customer load (to the substation). If the substation capacity was not increased, existing distribution lines would have to be extended for longer distances to reach the customers. Longer distribution lines result in higher line losses.

f. The Oakbrook and Aero substations discussed in response to a. above are included in the Company's CPCN filing in Case No. 2019-00251. The Company will seek CPCNs as necessary for projects that are not ordinary extensions of the existing system in the ordinary course of business.

PERSON RESPONSIBLE: Ash M. Norton – a. through e.
Legal – f.

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

PUBLIC AG-DR-01-115
(As to Attachment only)

REQUEST:

Refer to Norton Direct at p. 13, wherein he states that DEK's current distribution system "is constructed for one-way power flow in a radial design with limited ability to integrate renewable energy. As time progresses, this system will eventually evolve into a self-optimizing system."

a. Confirm that in order for renewable generation sources to be integrated directly into DEK's distribution system they would have to be located within DEK's service territory.

b. In light of the enactment of Senate Bill 100 in the 2019 Regular Session of the Kentucky General Assembly, regarding net metering, explain whether DEK foresees an expansion of customer-owned renewable generation within its service territory. Provide copies of any studies the Company may have conducted in this regard.

c. Discuss whether DEK's goal of evolving its distribution system to include self-optimization includes moving toward a multi-directional flow of power, similar to the multi-directional flow of power over a transmission system.

i. If so, confirm that DEK is planning on a very significant future penetration of distributed generation resources into its service territory.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

a. Confirmed.

b. Duke Energy Kentucky does foresee an expansion of net metering. See AG-DR-01-115(b) Confidential Attachment which presents the current Duke Energy Kentucky Net Metering forecast, showing cumulative capacity, customers, and energy. This confidential attachment will be provided to all parties upon the execution of a Confidentiality Agreement.

c. Yes. Refer to Norton Direct at p. 13, lines 8 – 11, wherein she states that the self-optimizing grid investments seek to "increase system "connectivity" by building more circuit ties that allow for more flexibility in restoration options. By tying more circuits together, the system will shift from a radial design to more of a "spider web" design. While we cannot predict the exact extent that there will be distributed generation resources into the Duke Energy Kentucky territory, these investments will allow for it if it were to happen.

PERSON RESPONSIBLE: John Verderame/Ash Norton – a.
Andrew Ritch – b.
Ash M. Norton – c.

2019-00271

AG-DR-01-115(b) CONFIDENTIAL ATTACHMENT

IS BEING FILED UNDER SEAL

AG-DR-01-116

REQUEST:

State whether DEK will incorporate the IEEE 1547 standard for interconnection and interoperability of distributed energy resources with associated electric power system interfaces. If not, explain why not.

RESPONSE:

Yes.

PERSON RESPONSIBLE: Andrew S. Ritch

AG-DR-01-117

REQUEST:

With regard to DEK's deployment of smart grid technologies, state how the Company intends to comply with FERC's approval of NERC's Critical Infrastructure Protection Standards (CIP-013-1).

RESPONSE:

The smart grid technologies do not include cyber assets that are subject to NERC CIP-013.

PERSON RESPONSIBLE: Ash M. Norton

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-118

REQUEST:

With regard to DEK's deployment of smart grid technologies, state to what extent the Company has examined the use of technologies involving: (i) Geographic Information System (GIS); and (ii) Blockchain, as a potential means of reducing costs associated with the use of both current and planned smart grid technology deployments. Include in your response:

a. whether GIS and/or Blockchain technologies could be used as cost-effective alternatives to such deployments;
b. whether any cost-effective GIS technologies could decrease the need and scope of any further planned ADMS and SCADA deployments;
c. whether GIS and/or Blockchain technologies could be used to integrate other IT and operational technologies in such a manner as to reduce costs;
d. whether GIS and/or Blockchain technologies can be utilized to reduce costs associated with reliability, resilience and grid security;
e. in the event DEK does at some point utilize GIS and/or Blockchain technologies, whether the Company could adopt existing platforms that would be interoperable with other systems, rather than creating a unique platform specially customized for the Companies' use; and copies of any

studies/analyses the Company may have conducted regarding the cost effectiveness, or cost/benefit studies regarding the use of such technologies.

RESPONSE:

a. GIS is an enterprise connectivity tool used to gather, manage and model Duke Energy's electric and gas facilities. It is the foundational layer that feeds into many of the Company's advanced systems, such as ADMS, and will continue to be used to sustain a modern grid. Duke Energy has performed preliminary research on Blockchain technologies, however, they are not currently being used as the technologies are in their infancy in the electric utility industry. Both GIS and Blockchain technologies are viewed as supplemental technologies, not alternatives, to smart grid technology deployments.

b. GIS technologies are currently used by Duke Energy enterprise wide and will continue to be used to sustain a modern grid. GIS is not an alternative but rather a complimentary foundational tool used with ADMS and SCADA. Duke Energy would not have an ADMS system without GIS.

c. GIS is a foundational tool and is currently being leveraged by several IT and operational technologies deployed across the enterprise to sustain a modern grid. As Blockchain technologies are in their infancy in the electric utility industry, it is too early to tell if or how they can be integrated with other IT and operational technologies to reduce costs.

d. GIS functionality alone cannot be used to reduce costs associated with reliability, resiliency and grid security, however, when paired with advanced systems, such as ADMS, certain efficiencies can be gained. Preliminary research has been performed on Blockchain technologies, however, as the technologies are in their infancy in the electric utility industry, it is too early to tell if they can be used to reduce costs associated with reliability, resilience and grid security.

e. Duke Energy currently uses the GIS connectivity tool enterprise wide. The tool is interoperable with other systems. Duke Energy is not currently utilizing Blockchain technologies, however, the Company's goal is always to introduce systems that are open and interoperable, where possible. As Blockchain technologies are in their infancy in the electric utility industry, Duke Energy has not conducted any cost effectiveness or cost/benefit studies or analyses regarding the use of Blockchain technologies.

PERSON RESPONSIBLE: Ash M. Norton

PUBLIC AG-DR-01-119

REQUEST:

Refer to Norton Direct, page 5, wherein he discusses the Donaldson Substation Expansion Project, which he states is driven by growth in several customer projects including the Amazon Air Hub, Erlanger Commerce Center and Marydale Business Park.

a. Provide the residential customer count served by this substation over each of the past five (5) years.

Confirm that these three projects are driven primarily by commercial class customers. Identify any industrial class customers included in these projects.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

a. Below is the total residential customer count served by the Donaldson Substation for the past five years.

	2014	2015	2016	2017	2018
Total	4833	4860	5046	5042	4963

b. Of the customers served by the Donaldson Substation approximately 920 are commercial. The industrial customers that are served by the Donaldson Substation include:

[redacted]

[redacted]

PERSON RESPONSIBLE: Ash M. Norton

AG-DR-01-120

REQUEST:

Provide distribution SAIDI, CAIDI and SAIFI indices for each of the past five (5) years, with and without the inclusion of major event days.

RESPONSE:

	INCLUDING MEDs		
	SAIDI	SAIFI	CAIDI
2018	214.74	0.94	228.45
2017	230.38	1.11	207.55
2016	180.98	1.04	174.02
2015	178.60	1.20	148.83
2014	128.86	1.08	119.31

	EXCLUDING MEDs		
	SAIDI	SAIFI	CAIDI
2018	81.82	0.66	123.97
2017	98.91	0.81	122.11
2016	101.67	0.77	132.04
2015	98.33	0.98	100.34
2014	116.38	1.02	114.10

PERSON RESPONSIBLE: Ash M. Norton

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-121

REQUEST:

Identify DEK's 10 worst performing circuits for each of the past five (5) years.

RESPONSE:

Below are the Circuit Rankings of the 10 worst performing circuits for each of the past five years.

	Top Ten Worst Performing Circuits (DEK) (1 is Worst)				
	2018	**2017**	**2016**	**2015**	**2014**
1	SILVER GROVE - H9320620041	CRESCENT - H9320700042	ATLAS - H9321700041	SILVER GROVE - H9320620043	OAKBROOK STA - H9322100041
2	CRITTENDEN - H9321240042	VERONA - H9321250042	DIXIE - H9320890042	WHITE TOWER - H9323040041	OAKBROOK STA - H9322100042
3	CRITTENDEN - H9321240041	BEAVER - H9320860041	DIXIE - H9320890041	CRITTENDEN - H9321240042	EMPIRE - H9322890041
4	DONALDSON - H9320550043	EMPIRE - H9322890042	DONALDSON - H9320550043	DECORSEY - H9322990041	LIMABURG - H9321890042
5	WHITE TOWER - H9323040041	VERONA - H9321250041	WHITE TOWER - H9323040041	AUGUSTINE - H9320780046	KENTON - H9320090043
6	CLARYVILLE - H9321470042	CLARYVILLE - H9321470042	SILVER GROVE - H9320620041	CONSTANCE - H9320420041	HEBRON - H9321520044
7	SILVER GROVE - H9320620043	AUGUSTINE - H9320780045	DONALDSON - H9320550041	AUGUSTINE - H9320780044	FLORENCE - H9322410046
8	KENTON - H9320090042	CLARYVILLE - H9321470041	WEST END STA - H40C0150041	HEBRON - H9321520045	VILLA - H9322430043
9	BUFFINGTON - H9320670044	ATLAS - H9321700041	CONSTANCE - H9320420043	KENTON - H9320090046	EMPIRE - H9322890042
10	CONSTANCE - H9320420042	COLD SPRING - H9321320049	RICHWOOD - H9321990041	KENTON - H9320090044	FLORENCE - H9322410045

PERSON RESPONSIBLE: Ash M. Norton

AG-DR-01-122

REQUEST:

Provide distribution line loss for each of the past five (5) years.

RESPONSE:

Below are the distribution line losses for each of the past five years. Beginning in 2016, the Company no longer calculates and tracks this data. The values for 2016 – 2018 are estimated values derived from interpolating using the system peak.

2018 - 13,359 kW
2017 - 12,974 kW
2016 - 14,346 kW
2015 - 13,301 kW
2014 - 16,423 kW

PERSON RESPONSIBLE: Ash M. Norton

AG-DR-01-123

REQUEST:

Refer to Norton Direct, page 6, wherein he states DEK's reliability investments "include but are not limited to, a measured deployment of self-optimizing grid technologies designed to minimize outage durations and enable faster restorations, as well as the replacement of aging infrastructure."

a. Provide a description of the self-optimizing technology.
b. Identify the circuits on which DEK intends to employ it.
c. Identify the aging infrastructure DEK intends to replace.

Provide the estimated average life span of the infrastructure DEK intends to replace, and the extent to which such equipment has been depreciated.

RESPONSE:

a. A description of self-optimizing grid is provided in Direct Testimony of Ash M. Norton, beginning on page 13, line 5.
b. In 2020, the planned circuits are Donaldson 43, Donaldson 44, Hands 43, and White Tower 42. In 2021, the planned circuits are Donaldson 41, Buffington 41, Buffington 45, and Buffington 47.
c. Objection. This request is overbroad and unduly burdensome to the extent it seeks detailed information regarding each and every piece of infrastructure that the Company intends to replace. Without waving said objection and to the extent

discoverable, please see Direct Testimony of Duke Energy Kentucky Witness Ash Norton pages 16-20.

PERSON RESPONSIBLE: As to objection, Legal
Ash M. Norton

AG-DR-01-124

REQUEST:

Provide a rank-order of all distribution capital expenditure projects during the test period, ranked from most expensive to least expensive, together with the purposes of each project.

RESPONSE:

Please see distribution capital expenditures during the test period at AG-DR-01-124 Attachment.

PERSON RESPONSIBLE: Christopher Jacobi

Capital Expenditures	Test Period
Elec - Distribution Plant	
HB - Distribution Substation	21,256
HW - Distribution Highway Jobs	2,418
IK - Distrib Lines OH/UG (Line Ext)	25,094
IO - Distribution Improvements	4,671
OU - Other Utility	110
QQ - Meters, Panel & Panel Troughs	105
RR - Communication	8,927
TB - Equipment & Tools	157
Elec - Distribution Plant - Total	62,738

AG-DR-01-125

REQUEST:

Provide the total sums spent on distribution undergrounding for each of the past five (5) years, together with projected costs of distribution undergrounding during the test period.

RESPONSE:

See response to STAFF-DR-02-021. The Company does not track separately the costs of initially placing distribution lines underground. These costs are recorded to FERC accounts 3660, 3670 and 3691 along with all other costs associated with underground lines as included on the "B Schedules" in the Company's filing.

PERSON RESPONSIBLE: Ash M. Norton
Melissa Abernathy
Christopher M. Jacobi

AG-DR-01-126

REQUEST:

Refer to Norton Direct, page 8, wherein he discusses DEK's Distribution Management System. State whether any of DEK's proposed distribution capital expenditures during the test period will include any deployment for Automated Distribution Management System (ADMS). If so:

a. Identify the circuits on which DEK intends to deploy the ADMS, and provide cost estimates for the deployment;
b. Discuss whether ADMS is duplicative of the company's abilities to use its new AMI system to locate outages; and
c. State whether DEK intends to seek a CPCN for such deployment. If not, why not?
d. State whether DEK has conducted any ADMS Testbed demonstrations in order to model and evaluate ADMS applications. If demonstrations were conducted, provide documents regarding the results of the Testbed demonstrations.
e. Identify the value streams DEK hopes to bring about through the deployment of ADMS.

RESPONSE:

Other than the Company's AMI project, projects related to smart grid initiatives that have been pursued are part of the normal extension of existing systems and replacements, and such programs are included in STAFF-DR-01-009 Attachment.

PERSON RESPONSIBLE: Ash M. Norton

AG-DR-01-127

REQUEST:

Refer to Norton Direct, page 9, wherein he discusses DEK's ability to call in additional repair crews from Duke Carolinas and Florida, when necessary. State whether DEK's mutual assistance program also utilizes contract crews. If so, will DEK call in a contract crew if it is less expensive than calling in crews from Duke Carolinas or Duke Florida? If not, why not?

RESPONSE:

At times, Duke Energy Kentucky does utilize contract crews for restoration efforts. Costs and time to restore are key considerations in which resources to deploy for restoration efforts. Native contract crew, based in or near Duke Energy Kentucky's service territory, often have a quicker response time since their driving distance is shorter. Typically, considering cost and time to restore results in utilizing these native contract crews before reaching out to internal crews from other regions.

PERSON RESPONSIBLE: Ash M. Norton

AG-DR-01-128

REQUEST:

State whether DEK utilizes, or plans to utilize distributed energy resources management systems ("DERMS"). If so:

a. Provide a discussion including the extent of such deployment and usage;
b. Describe the plans DEK has to incentivize the use of either customer-owned or independently owned distributed generation resources, including Qualifying Facilities; and
c. State whether DEK intends to seek a CPCN for such deployment. If not, why not?

RESPONSE:

Objection. This request is vague, overbroad, beyond the scope of the Company's application and calls for speculation. The Company has not proposed any incentives to customers owning distributed generation or qualifying facilities as part of this case.

PERSON RESPONSIBLE: Legal

AG-DR-01-129

REQUEST:

Refer to Reynolds Direct, Footnote 3. Provide an accessible link.

RESPONSE:

Financial Viability of Non-Residential Electric Vehicle Charging Stations. Chang, Daniel et al. UCLA Luskin School of Public Affairs. Aug 2012. Accessible via: https://luskin.ucla.edu/sites/default/files/Non-Residential%20Charging%20Stations.pdf

PERSON RESPONSIBLE: Lang Reynolds

AG-DR-01-130

REQUEST:

Refer to Staff-DR-01-055 Attachment – DEK Electric COSS 2019 Average Excess Macros Disabled, and then to tab WP FR-16(7)(v) Rate Incr.

a. Line 26 refers to Other Miscellaneous Revenues in the sum of $165,980. Explain the source of these revenues and provide a breakdown of this total.

RESPONSE:

Description	Source	Amount
Misc. Service Revenue - Acct. 451100	Sch. C-2.1	$ 297,504
Less:		
BDP Capacity Rev Adj	WPD-2.16	(67,392)
Bad Check Charges		(40,932)
Reconnection Charges		(45,600)
Plus:		
Tamper Penalty Fee Rev	Sch. D-2.21	22,400
Other Miscellaneous Revenue		$ 165,980

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-131

REQUEST:

Refer to Christie Direct, pages 11-12.

a. Confirm whether "Case No. 2017-00172" on page 11 is referring to Case No. 2017-00321.

b. Provide the results of the competitive bid process for vegetation management to award work in the Midwest market discussed by Mr. Christie.

RESPONSE:

a. Confirmed.

b. See AG-DR-01-131 Attachment.

PERSON RESPONSIBLE: TK Christie

			Planned Miles	Contractor - Proposed			
			289	Lewis		Asplundh	
SVC ID	Description	Order Unit	Units	Unit Cost	Expanded Cost	Unit Cost	Expanded Cost
1413255	Conv. Chip 1 sided (Standard) - Unit	UNITS	347	$1,020.77	$354,617.65	$1,094.99	$380,401.28
1413257	Conv. Chip 2 sided (Standard) - Unit	UNITS	188	$1,247.09	$234,006.56	$1,347.68	$252,881.39
1413254	Conv. Chip 1 sided (Complex) - Unit	UNITS	0	$1,624.29	$0.00	$1,347.68	$0.00
1413256	Conv. Chip 2 sided (Complex) - Unit	UNITS	0	$2,378.69	$0.00	$1,637.00	$0.00
1413259	Conv. No-Chip 1 sided (Standard) - Unit	UNITS	409	$762.12	$311,931.80	$758.07	$310,273.61
1413261	Conv. No-Chip 2 sided (Standard) - Unit	UNITS	106	$869.89	$91,815.94	$1,010.76	$106,684.34
1413258	Conv. No-Chip 1 sided (Complex) - Unit	UNITS	0	$1,020.77	$0.00	$1,010.76	$0.00
1413260	Conv. No-Chip 2 sided (Complex) - Unit	UNITS	0	$1,247.09	$0.00	$1,263.45	$0.00
1413253	Conv. Single Tree Prune - Unit	UNITS	74	$197.94	$14,624.39	$168.46	$12,446.51
1413243	Buck Single Tree Prune	UNITS	929	$136.07	$126,383.76	$141.22	$131,169.09
1413245	Buck. Chip 1 sided (Standard) - Unit	UNITS	2817	$587.53	$1,655,059.94	$529.58	$1,491,814.01
1413247	Buck. Chip 2 sided (Standard) - Unit	UNITS	152	$660.60	$100,714.25	$882.63	$134,565.01
1413244	Buck. Chip 1 sided (Complex) - Unit	UNITS	0	$916.33	$0.00	$988.54	$0.00
1413246	Buck. Chip 2 sided (Complex) - Unit	UNITS	0	$1,172.07	$0.00	$1,237.00	$0.00
1413249	Buck. No-Chip 1 sided (Standard) - Unit	UNITS	0	$490.11	$0.00	$423.66	$0.00
1413251	Buck. No-Chip 2 sided (Standard) - Unit	UNITS	0	$532.73	$0.00	$706.10	$0.00
1413248	Buck. No-Chip 1 sided (Complex) - Unit	UNITS	0	$762.89	$0.00	$776.71	$0.00
1413250	Buck. No-Chip 2 sided (Complex) - Unit	UNITS	0	$916.33	$0.00	$988.54	$0.00
1413252	Brushhog - Unit	UNITS	5	$0.00	$0.00	$553.60	$2,596.97
1413262	Hand Cut- Chip - Unit	UNITS	713	$1,404.90	$1,001,746.69	$1,179.22	$840,830.62
1413263	Hand Cut- No-Chip - Unit	UNITS	0	$730.54	$0.00	$673.84	$0.00
1413264	Clear Base of Pole- Chip - Unit	UNITS	201	$110.25	$22,109.92	$101.08	$20,270.83
1413265	Clear Base of Pole- No-Chip - Unit	UNITS	0	$96.27	$0.00	$84.23	$0.00
1413100	Removal no chip, 5" DBH up to 8" DBH - Capital	EA	143	$87.56	$12,527.37	$51.16	$7,319.82
1413101	Removal no chip, 5" DBH up to 8" DBH - O&M	EA	0	$87.56	$0.00	$51.16	$0.00
1413102	Removal no chip, 8" DBH up to 12" DBH - Capital	EA	270	$183.40	$49,468.39	$102.31	$27,596.63
1413103	Removal no chip, 8" DBH up to 12" DBH - O&M	EA	0	$183.40	$0.00	$102.31	$0.00
1413104	Removal no chip, 12" DBH up to 24" DBH - Capital	EA	413	$660.23	$272,549.34	$310.86	$128,326.87
1413105	Removal no chip, 12" DBH up to 24" DBH - O&M	EA	1	$660.23	$774.29	$310.86	$364.56
1413106	Removal no chip, 24" DBH up to 30" DBH - Capital	EA	74	$1,247.09	$92,140.26	$580.27	$42,872.69
1413107	Removal no chip, 24" DBH up to 30" DBH - O&M	EA	0	$1,247.09	$0.00	$580.27	$0.00

1413092	Removal and chip, 5" DBH up to 8" DBH - Capital	EA	40	$220.08	$8,775.26	$68.23	$2,720.60
1413093	Removal and chip, 5" DBH up to 8" DBH - O&M	EA	0	$220.08	$0.00	$68.23	$0.00
1413094	Removal and chip, 8" DBH up to 12" DBH - Capital	EA	168	$366.79	$61,512.87	$137.89	$23,124.85
1413095	Removal and chip, 8" DBH up to 12" DBH - O&M	EA	0	$366.79	$0.00	$136.43	$0.00
1413096	Removal and chip, 12" DBH up to 24" DBH - Capital	EA	332	$953.66	$316,511.68	$663.18	$220,104.01
1413097	Removal and chip, 12" DBH up to 24" DBH - O&M	EA	8	$953.66	$7,828.92	$663.18	$5,444.27
1413098	Removal and chip, 24" DBH up to 30" DBH - Capital	EA	90	$1,540.53	$139,113.72	$911.88	$82,345.24
1413099	Removal and chip, 24" DBH up to 30" DBH - O&M	EA	0	$1,540.23	$0.00	$911.88	$0.00
1413139	Danger Tree - Work Planning - $/Mile	MI	0	$61.23	$0.00	$50.09	$0.00
1413140	Danger Tree - 5" to 8" - $/unit	UNITS	176	$109.60	$19,280.18	$181.96	$32,009.38
1413141	Danger Tree - 8" to 12" - $/unit	UNITS	362	$340.99	$123,567.90	$363.90	$131,871.41
1413142	Danger Tree - 12" to 24" - $/unit	UNITS	501	$613.77	$307,358.96	$509.45	$255,117.09
1413143	Danger Tree - 24" to 30" - $/unit	UNITS	87	$1,227.53	$106,530.88	$873.33	$75,791.45
1413144	Danger Tree - Overhang - $/unit	UNITS	0	$293.67	$0.00	$225.62	$0.00
					$3,921,614.10		$3,689,742.47
				Cost/Mile =	$13,569.60	Cost/Mile =	$12,767.27
							-6%

Factors impacting pricing levels

S.No.	Factor name & description	% Increase
1	xxxx	y
2		
3		
4		
5		
6		
7		
8		
9		
10		

AG-DR-01-132

REQUEST:

Refer to Christie Direct, page 12. Of the 23 percent of all distribution related outages in 2018 that were due to vegetation management, what percentage were related to vegetation that originated outside the Company's right of way?

RESPONSE:

The Company does not track whether vegetation-related outages originated within or outside of the right of way.

PERSON RESPONSIBLE: T.K. Christie

AG-DR-01-133

REQUEST:

Refer to Christie Direct, pages 12-13. What is the test-year cost of DEK's Hazard Tree Program?

RESPONSE:

$766,750.

PERSON RESPONSIBLE: T.K. Christie

AG-DR-01-134

REQUEST:

Refer to Christie Direct, page 14. Why are costs related to the Hazard Tree Removal Program recorded as capital assets?

RESPONSE:

See response to STAFF-DR-02-033.

PERSON RESPONSIBLE: Melissa B. Abernathy

AG-DR-01-135

REQUEST:

Refer to Hunsicker Direct, page 8. Explain where, in its proceeding(s) seeking AMI meters, the Company indicated that a new CIS would be necessary to implement the experience intended.

RESPONSE:

Objection. This question is vague, overbroad, unduly burdensome insofar as it is asking the Company to review multiple proceedings. Moreover, this request is further objectionable as it misstates facts and misconstrues the testimony of Ms. Hunsicker. Without waiving said objection, and to the extent discoverable, Ms. Hunsicker is not claiming the Company's AMI meters are not delivering the benefits described in prior proceedings. To the extent the Attorney General is referring to the Company's Application in Case No. 2016-152, refer generally to the Direct Testimony of Dr. Sasha J Weintraub wherein he describes the enhanced basic services offered by the Company's then proposed "Metering Upgrade." In addition, and more specifically, see page 4, where Dr. Weintraub States the following: "[h]owever, in order to provide for those customer needs, Duke Energy must begin to evolve and change the way it provides its services. That requires investment in technologies that can enable such an evolution. The Metering Upgrade is that first step for Duke Energy Kentucky." The proposed CIS system is another step in that regard.

The deployment of AMI meters and the Customer Connect Program both support one of Duke Energy's strategic objectives to transform the customer experience. While complementary to the Company's broader modernization efforts, each of these initiatives has separate and distinct benefits independent of the other. Customer Connect is a standalone initiative that will benefit all customers, regardless of metering. In turn, AMI is a foundational investment that unlocks customer offerings that leverage AMI data and remote order capabilities. However, while the Customer Connect and AMI programs are not dependent on each other, the complement of both programs will add dimension to offerings for customers with AMI meters. Customer Connect will leverage the interval usage data to enhance existing offerings, as well as enable new rates, pricing structures and billing options. Today, the Company is limited in how to design, build and execute these offerings, given the constraints of the current billing system.

PERSON RESPONSIBLE: As to objection, Legal
Retha Hunsicker

AG-DR-01-136

REQUEST:

Refer to the Direct Testimony of Christopher Jacobi, pages 18-19, wherein he discusses other revenue projections.

a. Provide the calculation, derivation and/or determination of test year PJM reactive revenues.

RESPONSE:

Because any revenue for reactive service received by Duke Energy Kentucky from PJM flows through Rider PSM, the Company eliminates this item from the test year revenue requirement for base rates. See Schedule D-2.20.

PERSON RESPONSIBLE: Sarah E. Lawler

AG-DR-01-137

REQUEST:

Refer to the Direct Testimonies of James Mosley ("Mosley Direct") and John Verderame ("Verderame Direct"), generally. For the past three calendar years, and for 2019 to date, provide the following, excluding "behind the meter" resources:

a. Total number of hours each year that each DEK generating resource produced energy.

b. Total number of hours each year that each DEK generating resource produced energy while economically dispatched by PJM.

c. Total numbers of hours each year that each DEK generating resource produced energy while being dispatched by PJM for some other reason than being economic in the supply stack (i.e. uplift, reserves, etc.)

d. Total number of hours each year that each DEK generating resource produced energy while "self-scheduled."

RESPONSE:

a. The "Total number of hours each year that each DEK generating resource produced energy", or the "Service Hours", is shown in column (a) in the table below.

b. The "Total number of hours each year that each DEK generating resource produced energy while economically dispatched by PJM" is shown in the table below as "Economic dispatch by PJM Hours" in column (b). This value is simply the "DEK self-scheduled Hours" and "Dispatch by PJM for other reason Hours" subtracted from the "Service Hours".

c. The "Total numbers of hours each year that each DEK generating resource produced energy while being dispatched by PJM for some other reason than being economic in the supply stack (i.e. uplift, reserves, etc.)" is shown in the table below as "Dispatch by PJM for other reason Hours" in column (c). This value is zero for all years. The congestion and loss component of LMP has an impact on the dispatch and commitment of generating resources, but this is economic since it is part of economic dispatch. In addition, since reserves are co-optimized along with energy, the supply of reserves is also considered economic. Finally, resources committed for reliability are economic since to maintain reliability, this commitment was selected by PJM as the most economic option.

d. The "Total number of hours each year that each DEK generating resource produced energy while self-scheduled" is shown in the table below as "DEK self-scheduled Hours" in column (d). This value was calculated by examining each hour during the period for the commitment status and the difference between the minimum and maximum capability from the units offer. In the Day-Ahead market, if a unit was offered with a commitment status of Must Run, and at the same time the Minimum and Maximum offered capability were equal, for this response during this hour the unit was considered "Self-Scheduled". The reason why the commitment offer would be entered as Must Run and the

Minimum and Maximum capability were equal is typically to accomplish required testing or during times when the unit was in startup or shutdown. During startup and shutdown times, the unit(s) is unable to be dispatched by PJM and was required to remain at a defined output determined by the station.

2016	(a) Service Hours	(b) Economic dispatch by PJM Hours	(c) Dispatch by PJM for other reason Hours	(d) DEK self-scheduled Hours
East Bend U2	7,171	6,666	0	505
Woodsdale U1	187	184	0	3
Woodsdale U2	231	226	0	5
Woodsdale U3	204	202	0	2
Woodsdale U4	184	182	0	2
Woodsdale U5	210	208	0	2
Woodsdale U6	207	205	0	2

2017	(a) Service Hours	(b) Economic dispatch by PJM Hours	(c) Dispatch by PJM for other reason Hours	(d) DEK self-scheduled Hours
East Bend U2	7,749	7,392	0	357
Woodsdale U1	100	100	0	0
Woodsdale U2	95	95	0	0
Woodsdale U3	122	122	0	0
Woodsdale U4	49	49	0	0
Woodsdale U5	89	89	0	0
Woodsdale U6	88	88	0	0

2018	(a) Service Hours	(b) Economic dispatch by PJM Hours	(c) Dispatch by PJM for other reason Hours	(d) DEK self-scheduled Hours
East Bend U2	5,824	5,223	0	601
Woodsdale U1	434	434	0	0
Woodsdale U2	474	474	0	0

Woodsdale U3	462	462	0	0
Woodsdale U4	386	386	0	0
Woodsdale U5	459	459	0	0
Woodsdale U6	471	471	0	0

2019 (YTD)	(a) Service Hours	(b) Economic dispatch by PJM Hours	(c) Dispatch by PJM for other reason Hours	(d) DEK self-scheduled Hours
East Bend U2	7,827	7,418	0	409
Woodsdale U1	379	379	0	0
Woodsdale U2	354	354	0	0
Woodsdale U3	446	428	0	18
Woodsdale U4	381	381	0	0
Woodsdale U5	363	363	0	0
Woodsdale U6	304	304	0	0

2019 data is through September, 2019

PERSON RESPONSIBLE: John Verderame

AG-DR-01-138

REQUEST:

Refer to Verderame Direct and Mosley Direct, generally. Explain DEK's actual interaction and involvement in PJM's FTR market. Any response should include a narrative explanation of DEK's participation in annual and/or long-term products, and the magnitude of participation in either or both.

RESPONSE:

Duke Energy Kentucky participates in both PJM Annual and Long-Term FTR Auction to buy FTRs for its native customers, up to the forecast expected generation to serve its load. PJM allocates Auction Revenue Rights (ARRs) to Duke Energy Kentucky on an annual basis. Duke Energy Kentucky converts the ARRs into FTRs in the Annual FTR Auction. If the amount of FTRs needed exceeds the allocated ARRs, Duke Energy Kentucky will bid the difference either in the Annual or Long-Term FTR Auction. Duke Energy Kentucky also participates in the monthly FTR auctions to true up the FTR portfolio with the updated expected generation forecast.

PERSON RESPONSIBLE: John Verderame

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-139

REQUEST:

Refer to Verderame Direct, page 9, wherein he states that for IRP purposes DEK uses UCAP, while PJM's planning reserve margin is calculated on an ICAP basis. Provide a citation to PJM's governing documents wherein they note that PJM's planning reserve margin is calculated on an ICAP basis.

RESPONSE:

Note that on page 9, lines 12 and 13 of the direct testimony of John Verderame, the terms UCAP and ICAP were mistakenly switched. The correct sentence should have read "For IRP purposes, this is done on an ICAP basis versus the PJM planning reserve margin which is calculated on an UCAP basis."

Please refer to PJM Manual 20 Section 1.4 and 1.5.

https://www.pjm.com/-/media/documents/manuals/m20.ashx

PERSON RESPONSIBLE: John Verderame

AG-DR-01-140

REQUEST:

Refer to Verderame Direct, pages 15–20.

a. Explain DEK's considerations when determining when to "self-schedule" generating resources vs. waiting to operate pursuant to PJM's direction.

b. Explain how DEK's self-scheduling impacts Rider PSM.

c. Explain how if DEK only participates in PJM, how DEK makes off-system sales.

d. Explain, in detail, DEK's participation in "off-system sales," including its considerations in determining when to make off-system sales.

RESPONSE:

a. Duke Energy Kentucky performs an economic review each business day to inform the commitment status decision for each coal unit. The planning process is designed to minimize the total customer cost by maximizing the unit's economic value. This review projects expected operating margins from operation of the unit for the next 7-14 days based on operating parameters and expected market prices. This is not a complete economic analysis as it only considers expected revenue received from forecasted locational marginal prices ("LMP") and variable generation production costs incurred from operation of the units and does not incorporate other operational or reliability considerations.

However, in making the decision regarding an individual unit's offer status, the Company also considers additional factors such as the expected PJM settlement impact (such as the ineligibility of operating reserve payments when a generating unit is self-committed), and the capability and economic impact from cycling the generating unit off-line and/or on-line.

Since East Bend typically receives more revenues from the PJM market than variable costs necessary to run the unit (meaning it is usually "in-the-money"), generally the Company self-commits East Bend into the PJM energy markets with PJM then economically dispatching the unit between its minimum and maximum capability per the offer. Since the Woodsdale units tend to be much more marginal in nature, typically the Company relies on PJM to commit these units.

b. The Company's self-commitment of East Bend is designed to result in the lowest variable costs to the Company's customers by eliminating uneconomic unit start-ups and shutdowns such as over a weekend. During these times when PJM may have de-committed East Bend had it not been for the Company's offer, it is possible that this would have had a minimal impact on off-system sales in the PSM.

c. The Duke Energy Kentucky generating units are economically committed and dispatched into the PJM market with their output independent of the Company's native customer load. The amount of generation produced from the Company's generation units is almost never equal to the amount of native load demand. Notwithstanding certain stacking logic, when the amount of generation in an hour is greater than then native load demand, the result is an off-system sale to PJM.

d. Refer to (c) above.

PERSON RESPONSIBLE: John Verderame

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-141

REQUEST:

Refer to Verderame Direct, page 19. Explain to what degree DEK's generation costs and revenues have been modified in this Application as compared to DEK's application in Case No. 2017-00321 considering the changes to PJM's markets, including, but not limited to the ability to include certain operations and maintenance costs in energy bids not previously permitted.

RESPONSE:

Objection. This request is vague, over broad and calls for speculation insofar as it refers to changes in PJM markets. Without waiving said objection, and to the extent discoverable, due to a PJM rule change to the fuel cost policy Duke Energy Kentucky can now include certain operating and maintenance costs into the Woodsdale cost based offers. This change was an important change that benefits our customers, allowing the cost based offer for the units to be more representative of the actual costs to start and operate the units. As discussed in previous testimony, the Company added oil as a back-up fuel source at Woodsdale Station to address PJM's capacity performance rules. Aside from this addition, DEK's generation costs and revenues in this application have not been modified from the previous application due to changes to PJM's markets.

PERSON RESPONSIBLE: As to objection, Legal
John Verderame

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-142

REQUEST:

Refer to Verderame Direct, page 23, wherein he states that DEK "continues to evaluate the merits of exiting the FRR obligation and becoming a full RPM auction participant." Provide DEK's most-recent evaluation of such a scenario.

RESPONSE:

Duke Energy Kentucky continues to monitor this decision on a routine basis. Currently, Duke Energy Kentucky is waiting for a response from FERC regarding PJM's MOPR filing which will help shape Duke Energy Kentucky's decision-making process on this going forward.

PERSON RESPONSIBLE: John Verderame

AG-DR-01-143

REQUEST:

Refer to Verderame Direct, pages 25-26. Explain the cause or causes of zones clearing the BRA at a different price than "Rest of RTO." Explain whether DEK is aware of the cause or causes that led to the DEOK zone clearing at a different price than "Rest of RTO" for the auction for the 2020/2021 Delivery Year.

RESPONSE:

In RPM construct, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. The clearing solution may require committing capacity resources in an out-of-merit order, but again in a least-cost manner to ensure that these constraints are respected. In those cases where one or more of the constraints results in an out-of-merit commitment in the auction solution, the LDA clearing price will be reflective of the price of resources selected out of merit to meet the necessary requirements.

Duke Energy Kentucky is not aware of the root cause that led to higher DEOK zone clearing price because PJM does not publish the exact causes of zonal price separation in any capacity auction. Please refer to page 25 of the PJM BRA report for main factors impacting the 2020/2021 clearing prices relative to 2019/2020 BRA price.

https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en

PERSON RESPONSIBLE: John Verderame

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-144

REQUEST:

Refer to Verderame Direct, page 29, wherein he notes that he believes "East Bend meets the minimum requirements of a Capacity Performance resource in that it is a coal-fired facility that maintains a significant reserve of fuel stored on-site."

a. Over the past five (5) years, provide the number of annual hours East Bend has had a "forced outage."

b. Provide the primary causes of the "forced outages" provided above.

c. Provide the number of annual hours for the past five (5) years in which lack of fuel has been a cause of a forced outage for East Bend.

d. Across the Duke Energy territories, is the absence of on-site fuel a top-three (3) cause of forced outages over the past three (3) years? Any response should differentiate between base load and peaking generating resources in the event the designation affects the response.

RESPONSE:

a.

Forced Outage Annual Hours

	2014	**2015**	**2016**	**2017**	**2018**
East Bend U2	551	196	355	414	263

Note: Based on GADS data for event types: U1, U2, U3 and SF

b. The primary causes for forced outages for East Bend U2 from 2014-2018 were: Secondary superheater tube leaks, Generator main flex links failure and Secondary reheater tube leaks. These are based on GADS data (top 3 event descriptions).

c. East Bend U2 has experienced zero forced outage hours from 2014 – 2018 due to lack of fuel.

d. Objection. This request is overbroad, unduly burdensome and seeks information that is irrelevant to this proceeding. This request seeks information for utilities not regulated by the Kentucky Public Service Commission, and that are not members of PJM. As such, it is not only irrelevant, but is not likely to lead to the discovery of any relevant or admissible evidence.

PERSON RESPONSIBLE: As to objection, Legal
J. Michael Mosley

AG-DR-01-145

REQUEST:

Refer to Verderame Direct, page 30, wherein he notes that "To date there have been no system wide Capacity Performance Hours called by PJM that resulted in assessments or bonuses." Explain whether this is still the case, and whether there have been any recent performance assessment intervals called by PJM. Consider this an on-going request.

RESPONSE:

PJM experienced Capacity Performance Assessment Hours on October 2, 2019 in the AEP, BGE, DOM, and PEPCO Zones.

- BGE, DOM and PEPCO Zones Assessment Hours began at 2 PM EPT and concluded at 3:45 PM EPT.
- AEP Zone Assessment Hours began at 2 PM EPT and concluded at 4 PM EPT.

PERSON RESPONSIBLE: John Verderame

AG-DR-01-146

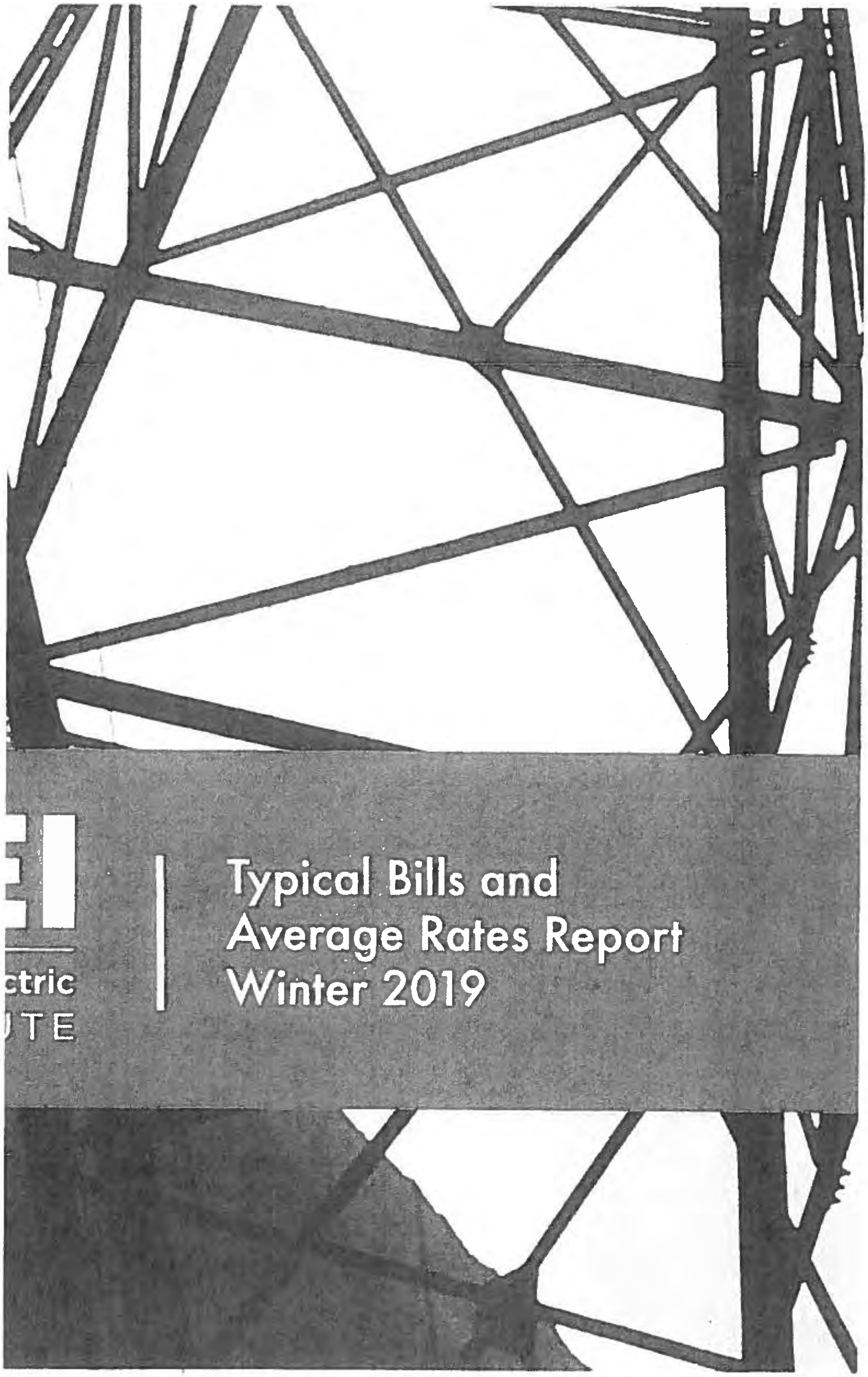
REQUEST:

Refer to Wathen Direct, page 10, wherein he discusses "the most recent report from the EEI Typical Bills and Average Rate Report Winter 2019 (EEI Report)." Provide a copy of the cited report.

RESPONSE:

Duke Energy Kentucky possesses only one hard copy of a voluminous report. AG-DR-01-146 Attachment includes copies from the pages relevant to the information cited in Mr. Wathen's testimony.

PERSON RESPONSIBLE: William Don Wathen Jr.



Typical Bills and Average Rates Report Winter 2019

Edison Electric Institute

Typical Electric Bills

(in $/month)

Residential Rates in effect January 1, 2019

		General Service			Fuel Clause Adjustment (FCA) in cents:	
		500 kWh	750 kWh	1000 kWh		
Average For South Atlantic						
	generation	$34.37	$51.55	$68.56		
	transmission	$5.29	$7.94	$10.60		
	delivery	$26.41	$35.40	$44.19		
	total rate	$64.28	$91.07	$117.54		
East South Central						
Alabama						
Alabama Power Company					FCA	2.298
	total rate	$76.42	$107.15	$134.95		
Average For Alabama						
	total rate	$76.42	$107.15	$134.95		
Kentucky						
AEP (Kentucky Power Rate Area)					FCA	0.00825
	total rate	$72.14	$100.37	$128.56		
Duke Energy Kentucky					FCA	0.00434
	total rate	$50.49	$70.19	$89.89		
Kentucky Utilities Company					FCA	-0.088
	total rate	$56.15	$77.93	$99.71		
Louisville Gas & Electric Company					FCA	0.081
	total rate	$59.25	$82.56	$105.86		

Edison Electric Institute

Typical Electric Bills

(in $/month)

Residential Rates in effect January 1, 2019

		General Service			Fuel Clause Adjustment (FCA) in cents
		500 kWh	750 kWh	1000 kWh	
Average For USA					
	generation	$38.45	$58.06	$77 27	
	transmission	$8.07	$12 13	$16 15	
	delivery	$37.44	$51 66	$65 65	
	ctc	$2.52	$5.15	$7.74	
	total rate	$73.97	$106.54	$138.58	

AG-DR-01-147

REQUEST:

Refer to Wathen Direct, page 12. Was the question and answer restated on page 12 that of the Attorney General or Mr. Lane Kollen?

RESPONSE:

As it relates to Mr. Wathen's testimony on page 12, the question is unanswerable. Assuming the question is asking about the question and answer restated on page 13, the quote is taken from the direct testimony of Lane Kollen in Case No. 2018-00261, on page 6, lines 6 through 9. Inasmuch as it is 'direct' testimony, the question would have been submitted by the Attorney General and response was provided by Mr. Kollen.

PERSON RESPONSIBLE: Legal
William Don Wathen Jr.

AG-DR-01-148

REQUEST:

Refer to Wathen Direct, page 14. Provide the $/kWh average fuel and purchased power rate included in base rates.

RESPONSE:

$0.023837 per kWh.

PERSON RESPONSIBLE: William Don Wathen Jr.

AG-DR-01-149

REQUEST:

Refer to Kern Direct, pages 12–13.

a. Explain how using two-year average PJM LMP at the DEK node as the avoided energy cost is in compliance with PURPA and the applicable Kentucky regulations.

b. Explain how using PJM Real-Time LMP to determine the Energy Purchase Rate for Large QFs is in compliance with PURPA and the applicable Kentucky regulations.

c. DEK's proposed Large QF tariff, Fifth Revised Sheet No. 94, only provides rates for purchases under the "as available" option under 807 KAR 5:054 Section 7 (4)(a). Provide the calculation used by DEK to determine the avoided costs for a large QF with a legally enforceable obligation as required in 807 KAR 5:054 Section 7 (4)(b), should the large QF choose the "avoided costs at the time the legally enforceable obligation is incurred."

RESPONSE:

a. Objection. Calls for a legal opinion. Without waiving said objection, and to the extent discoverable, the PJM LMP at the DEK Load Zone is the avoided energy cost for the Company. It is equal to the price that the utility would pay for energy if not for the generation provided by the QF. PURPA and Kentucky regulations designate the price be based on avoided cost.

b. Objection. Calls for a legal opinion. Without waiving said objection, and to the extent discoverable, the PJM LMP at the DEK Load Zone is the avoided energy cost for the Company. It is equal to the price that the utility would pay for energy if not for the generation provided by the QF. PURPA and Kentucky regulations designate the price be based on avoided cost.

c. 807 KAR 5:054 Section 7(4) states that "these rates shall be used only as the basis for negotiating a final purchase rate with qualifying facilities…". The starting point for negotiations for a qualifying facility that chooses the avoided cost at the time that the legally enforceable obligation is incurred would be the PJM Real-Time Locational Marginal Price for power at the DEK Aggregate price node. the Company would benchmark negotiations based on the two-year LMP average as stated in the tariff for Small QFs.

PERSON RESPONSIBLE: Legal (as to objection) / Jeff L. Kern

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-150

REQUEST:

Refer to Kern Direct, page 13, wherein he notes that the Large QF "Capacity Purchase Rate is based on the Company's avoided capacity cost calculated using data from the Company's 2018 IRP." Explain if there are any market-based price signals DEK could use to determine a reasonable capacity cost, such as results from PJM Base Residual Auctions.

RESPONSE:

Duke Energy Kentucky is a Fixed Resource Requirements (FRR) entity in PJM and as such an entity, predominantly relies on owned and planned generation to fulfill PJM capacity requirements. Therefore, the Company uses the IRP information to determine avoided capacity value. While PJM market based capacity prices exist, IRP based avoided cost is more appropriate.

PERSON RESPONSIBLE: Jeff L. Kern

AG-DR-01-151

REQUEST:

Refer to Kuznar Direct, pages 2–3, wherein he states that the BESS will provide ancillary services through PJM's "frequency regulation market which is the primary application for the deployment of the system."

a. Provide the BESS's Net Present Value Revenue Requirement of the ancillary service revenues/benefits over the life of the system.

b. Provide the BESS's Net Present Value Revenue Requirement of the costs of the system, including capital and O&M over the life of the system.

RESPONSE:

a. $5.26 MM

b. Please see AG-DR-01-109(c) Confidential Attachment.

PERSON RESPONSIBLE: Zachary Kuznar

AG-DR-01-152

REQUEST:

Refer to Kuznar Direct, page 3.

a. Describe how many customers, the type of customers and the usage characteristics of customers that will be connected to the "islanded portion of the distribution circuit" DEK proposes to connect the BESS to.

RESPONSE:

See response to STAFF-DR-02-080. This question is no longer applicable as the location of the proposed battery project has changed and it is no longer providing islanding services to the Hospital.

PERSON RESPONSIBLE: Zachary Kuznar

AG-DR-01-153

REQUEST:

Refer to Lawler Direct, page 9, and WPD-2.20a. Provide the derivation of the test year revenues and expenses for (1) Sales for Resales – Outside, (2) Ancillary Services – Reactive, (3) Rider PSM, (4) Fuel Expense and (5) Reactive Power.

RESPONSE:

(1) See response to AG-DR-01-053.

(2) See response to AG-DR-01-136.

(3) Rider PSM revenues are determined based on forecasted amounts for certain items covered by the Rider PSM, including the sharing credit related to non-native sales. Rider PSM activity has been excluded from the test year at Schedule D-2.20.

(4) The Fuel Expense included at WPD-2.20a is fuel expense related to non-native sales. The forecast for non-native revenue and non-native fuel expense is derived from the GenTrader production cost model, which is described in the testimony of John Verderame. Non-native revenues and fuel expenses are eliminated from the test year at Schedule D-2.20.

(5) Reactive Power expenses were estimated by using an average of PJM billing line item 1330, Reactive Supply and Voltage Control from Generation and Other Sources Service.

PERSON RESPONSIBLE: Sarah E. Lawler
Christopher M. Jacobi

AG-DR-01-154

REQUEST:

Refer to the Application, Schedule F-1.

a. Identify by name the "Social Organization/Service Club" on lines 1–15 that are proposed to receive amounts in the forecasted period.

b. Provide a breakdown of the items included in "Various Budgeted Items" in the base period and the test-year for lines 1–15 and line 24. Any response should identify recipients by name.

RESPONSE:

As noted on page 13 of the testimony of Ms. Sarah E. Lawler, all amounts on Schedule F-1 are either below the line or have been removed from operating expenses on Schedule D-2.23 and thus not included in the forecasted test period revenue requirement. The Company does not budget these items at any further detail than what has been provided on these schedules.

PERSON RESPONSIBLE: Sarah E. Lawler

AG-DR-01-155

REQUEST:

Refer to the Application, Schedule F-2.1, line 27, "Various Budgeted Items."

a. Explain why the test-year amount of $177,268 exceeds the base period amount of $66,434 by more than $100,000, and exceeds the base period amount for all categories of $160,382.

b. Provide a breakdown of the items included in "Various Budgeted Items" in the base period and the test-year. Any response should identify recipients by name.

RESPONSE:

As noted on page 13 of the testimony of Ms. Sarah E. Lawler, all amounts on Schedule F-2.1 are charged below the line and thus not included in the forecasted test period revenue requirement. The Company does not budget these items at any further detail than what has been provided on these schedules. The test period amount of $177,268 is comparable to the $160,382 base period amount.

PERSON RESPONSIBLE: Sarah E. Lawler

REQUEST:

Refer to the Application, Schedule F-7, line 9, "Various Budgeted Items."

a. Explain why the test-year amount of $599,488 exceeds the base period amount of $286,400 by more than $300,000, and exceeds the base period amount for all categories of $417,032.

b. Provide a breakdown of the items included in "Various Budgeted Items" in the base period and the test-year. Any response should identify recipients by name.

RESPONSE:

As noted on pages 14 and 15 of the testimony of Ms. Sarah E. Lawler, all amounts on Schedule F-7 are charged below the line and thus not included in the forecasted test period revenue requirement. The Company does not budget these items at any further detail than what has been provided on these schedules. The test period amount of $599,488 is comparable to the $417,032 base period amount.

PERSON RESPONSIBLE: Sarah E. Lawler

AG-DR-01-157

REQUEST:

Provide a copy of DEK's most recent version of its FERC Form 715 criteria.

RESPONSE:

Please see AG-DR-01-157 Attachment (Form 715).

PERSON RESPONSIBLE: Tim Abbott

United States of America

Federal Energy Regulatory Commission

FERC FORM 715

Annual Transmission Planning and Evaluation Report

Duke Energy Ohio and Duke Energy Kentucky

Part 4: Transmission Planning Reliability Criteria

Duke Energy Ohio and Duke Energy Kentucky adheres to any applicable NERC and RFC Reliability Standards.

Duke Energy Ohio and Duke Energy Kentucky also has its own detailed planning criteria, which are shown on the following pages. Violations of these criteria would result in one or several of the following actions: expansion of transmission system; operating procedures; or a combination of the two. Acceptance of operating procedures is based on engineering judgment with the consideration of the probability of violation weighed against its consequences and possibly other factors.

Voltage

Bus voltages are screened using the Transmission System Voltage Limits below. These Limits specify minimum and maximum voltage levels during both normal and single contingency conditions. Emergency Voltage Limits are defined as the upper and lower operating limits of each bus on the system.

The voltage limits are expressed as a percent of the nominal voltage.

Under conditions beyond single contingencies, voltages above or below these limits may occur. These conditions should be investigated to determine what actions, if any, are required so that they would not result in wide-spread outages. Should post-contingency transmission voltages in a general area drop below 90% of nominal, closer examination is warranted to determine whether voltage collapse for such contingency conditions is likely.

Transmission System Voltage Limits

Nominal Voltage (kV)	Normal Voltage Limits		Emergency Voltage Limits	
	Minimum	Maximum	Minimum	Maximum
345	95%	105%	90%	105%
132	95%	107.5%	90%	107.5%
66	95%	107.5%	90%	107.5%

Thermal

The following guidelines shall be used to ensure acceptable thermal loadings:

a) Under normal conditions, no facility should exceed its continuous thermal loading capability.

b) For a single contingency no facility should exceed its emergency loading capability.

Stability

The stability of the Duke Energy Ohio and Duke Energy Kentucky systems and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC and RF Reliability Standards. Generating units must maintain angular stability under various contingency situations. Many different contingencies are considered and the selection is dependent on the location within the transmission system.

Fault Duty

All circuit breakers should be capable of interrupting the maximum fault current duty imposed on the circuit breaker.

Single Contingencies

The thermal and voltage limits should not be violated for either normal operations or under the loss of:

a) A single transmission circuit
b) A single transformer
c) A single generating unit
d) A single reactive power source or sink

Severe Contingencies

NERC Reliability Standards instruct transmission planners to evaluate extreme (highly improbable) contingency events resulting in multiple elements removed or cascading out of service. Severe contingencies are evaluated to determine the impact on the transmission system and on the surrounding interconnected transmission system. The severity of the consequences, availability of emergency switching procedures, probability of occurrence and the cost of remedial action will be considered in the evaluation of these contingencies.

For example double contingency line outages are considered in cases involving 138 kV underground cable feeders, which supply the West End and Charles substations in the Cincinnati, Ohio metropolitan area. For an outage of any other line with one such underground circuit out of service, the loading on all lines should be no higher than 100% of the emergency conductor rating and voltage should be 90% or higher at all points on the 138 kV system.

These planning criteria are not intended to be absolute or applied without exception. Other factors, such as severity of consequences, availability of emergency switching procedures, probability of occurrence and the cost of remedial action are also considered in the evaluation of the transmission system.