KyPSC Case No. 2021-00190
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AG-DR-02-001

REQUEST:

Did the Company receive funds under the Paycheck Protection Program? If it did:

a. Provide the total amount received under the program.

b. Discuss whether that amount must be repaid.

c. Discuss how those funds were applied.

d. Discuss whether those funds offset increases to the revenue required by the Company.

RESPONSE:

No, the Company did not receive funds under the Paycheck Protection Program.

PERSON RESPONSIBLE: Jake J. Stewart

AG-DR-02-002

REQUEST:

Identify all association dues included in the revenue requirement. For each organization whose dues were included for recovery from ratepayers:[1]

a. Provide the name of the association to which those are paid;

b. Provide the amount;

c. Provide a description of the services the association provides to the Company;

d. Discuss whether the association engages, directly or indirectly, in: (i) lobbying; (ii) political activities; (iii) regulatory advocacy; and/or (iv) public relations;

e. Provide copies of the studies or other information DEK relied upon in making its decision on whether to include a test-year amount of dues for each such organization;

f. Provide copies of all actual regulatory advocacy in which each such organization engaged before the Commission; and

g. Discuss whether any portion of the dues paid to that association have been removed from the revenue requirement.

RESPONSE:

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[1] Including, but not limited to the American Gas Association.

a. Dues are included in the test year revenue requirement for the following organizations:

Line No.	Organization	Total Dues
1	American Gas Association (AGA)	$ 50,000
2	Interstate Natural Gas Association of America (INGAA)	5,000
3	Midwest ENERGY Association (MEA)	20,000
4	Operations Technology Development (OTD)	50,000
5	Total Dues in the Test Year	$125,000

b. See response to (a) above.

c. The Company receives many benefits from its membership in various associations such as (i) programs to help enhance the safe delivery of natural gas to customers, (ii) advocacy for natural gas industry issues, (iii) the exchange of information among members to help achieve operational excellence, (iv) help in responding to energy needs of customers, regulatory trends and emerging technologies, (v) collaboration with industry peers to learn successful practices of other members, and (vi) the combining of resources with other member to develop advanced technologies for the natural gas industry. More information concerning benefits of membership can be found on the websites of the various organizations.

d. The AGA works with elected political leaders on key issues that could have an impact on its member companies, the energy utility sector and gas customers. INGAA is a trade organization that advocates regulatory and legislative positions of importance to the natural gas pipeline industry in North America.

e. The Company did not rely on studies or other information when deciding to include dues for each organization in its test-year. The benefits of membership in these organizations provide customers and the public ongoing safety, efficiency and productivity in Duke Energy Kentucky's operations.

f. The AGA routinely comments on numerous regulatory matters directly affecting AGA members at the Federal Energy Regulatory Commission, Environmental Protection Agency, Department of Energy, Department of Transportation/Pipeline and Hazardous Materials Safety Administration, and other federal agencies. The Company is not aware that the AGA or any of the other agencies listed in response to part (a) may have engaged in regulatory advocacy before the Kentucky Public Service Commission.

g. None of the $125,000 listed in the table above have been removed from the test year revenue requirement.

PERSON RESPONSIBLE: Jay P. Brown / Abby L. Motsinger – a., b., g.
Brian R. Weisker – c., d., e., f.

AG-DR-02-003

REQUEST:

Reference the response to AG DR 1-1 (d). Explain whether the statement, "The Company made reasonable payment arrangements, typically 3-6 months in length, available to customers upon request," [emphasis added] refers to payment plans offered to customers after Nov. 6, 2020. If not, explain how DEK's offering of payment plans complied with the referenced Governor's Order, and with the Commission's Order dated Sept. 21, 2020 in Case No. 2020-00085, that payment plans had to be six months.

RESPONSE:

The Company complied with the referenced Governor's Order as well as the Commission's Order dated September 21, 2020. The Company placed all accounts with an arrearage, that were not already on a voluntary payment plan, on a default payment plan as was directed by the Commission. Customer accounts that accumulated arrearages after November 6th, 2020, that were not in default, were offered reasonable payment arrangements, typically 3-6 months in length, upon request. The Company followed all Commission and Governor orders pertaining to payment plans.

PERSON RESPONSIBLE: Lesley G. Quick

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-004

REQUEST:

Refer to the Company's responses to AG 1-6.

a. Provide the PHMSA inspection expense incurred in each year 2018 through 2020, budgeted for 2021, the base year, and the test year by FERC O&M expense account/subaccount separated into one-time (baseline) inspection expenses and ongoing inspection expenses and in total for each category for each year. Provide a ten-year forecast of one-time (baseline) and ongoing inspection expenses by year from 2022 through 2031 by FERC O&M expense account/subaccount and in total for each category by year.

b. Confirm that the Company agrees certain of the PHMSA inspection expenses were and are being incurred to establish a baseline for inspection, correction, and reporting purposes. Identify and describe each category of these expenses.

c. Confirm that the Company agrees that certain of the PHMSA inspection expenses are ongoing, but periodic. Identify and describe each category of these expenses. To the extent possible, describe the frequency required for each major type of PHMSA inspections.

d. Provide the integrity management expenses, including the PHMSA inspection expenses, incurred in each year 2018 through 2020, budgeted for 2021, the base year, and the test year by FERC O&M expense account/subaccount separated into one-time (baseline) integrity management expenses and ongoing integrity management expenses and in total for each category for each year. Provide a ten-year forecast of one-time (baseline) and ongoing integrity management expenses by year from 2022 through 2031 by FERC O&M expense account/subaccount and in total for each category by year.

e. Confirm that the Company agrees certain of the integrity management expenses were and are being incurred to establish a baseline for inspection, correction, and reporting purposes. Identify and describe each category of these expenses.

f. Confirm that the Company agrees that certain of the integrity management expenses are ongoing, but periodic. Identify and describe each category of these expenses. To the extent possible, describe the frequency required for each major type of PHMSA inspections.

RESPONSE:

a. See AG-DR-02-004 Attachment for the 2018 – 2020 actuals, 2021 budget, base year, and test year information. The PHMSA inspection expenses are all ongoing expenses. The Company does not develop 10-year forecasts at this level of the O&M budget.

b. The Company agrees that the PHMSA inspection expenses do represent a baseline for inspection, correction, and reporting purposes. Major categories are included in CFR, Title 49, Subtitle B, Chapter 1, Subchapter D, Part 192, Subparts L & M and include class location studies, damage prevention and public awareness programs, control room management, pipeline surveillance and patrolling for factors affecting safety and operation (e.g., indications of leaks, construction activity), leak survey and atmospheric corrosion surveys, valve inspections, regulator station inspection, and meter inspection.

c. Some of the categories listed in AG-DR-02-004 Attachment have inspection requirements greater than one year and the Company attempts to divide these obligations into equal portions to spread evenly over each year. Examples of inspection requirements: Class location studies (annual), damage prevention and public awareness programs (annual), control room management (continuous), pipeline surveillance and patrolling for factors affecting safety and operation (annual), leak survey and atmospheric corrosion surveys (3-year cycle), valve inspections (annual), and regulator station inspection (annual).

d. Please see AG-DR-02-004 Attachment for the 2018 – 2020 actuals, 2021 budget, base year, and test year information. The integrity management expenses are all ongoing expenses and are dependent on anticipated assessments. The Company does not develop 10-year forecasts at this level of the O&M budget.

e. The Company agrees that the integrity management expenses do represent a baseline for inspection, correction, and reporting purposes for distribution integrity management. These expenses are typically consistent each year but can change dependent on identification of new risks in need of mitigation. Some examples of these programs are damage prevention, records management, cross-bore, and bare steel piping elimination.

f. Transmission integrity management expenses are developed annually dependent on anticipated assessments. Transmission integrity assessments (CFR, Title 49, Subtitle B, Chapter 1, Subchapter D, Part 192, Subpart O) are typically on 7-year cycles, so O&M costs will vary from year to year depending on where the Company is in the cycle. The specific inspection technique used for assessment is based on identified threats. The Company uses direct assessment, in-line inspection, and pressure testing as assessment techniques.

PERSON RESPONSIBLE: Brian R. Weisker

AG-DR-02-004(a)

Sum of Monetary Amount JD				Fiscal Year CMD			Budget	Base Year	Test Year	PHMSA	Integrity
Account ID CB	Account Long Descr CB	Project ID CB	Project Long Descr CB	2018	2019	2020	2021	6mo Act, 6 mo:	2022 Budget	Inspection	Management
0863000	Transm-Maint of Mains	863MEGA	Mega Rule - Trans Maint Total		693.72	9,719.72	189,761.29	124,664.67	189,761.29		x
0863000	Transm-Maint of Mains	863MNTPIG	Transmission Pigging Total		166,557.74						x
0863000	Transm-Maint of Mains	863PIPINT	Main Pipe Integrit-Trans Maint Total		245,019.63	178,314.28	327,141.67	269,015.12	327,141.67		x
0871000	Distribution Load Dispatching	GCESD	Gas Control Operations Total	144,122.12	221,860.33	224,465.58	257,635.48	252,309.10	257,635.48	x	
0874000	Mains And Services	REGOSE	Regulator and System Station Pressure Ac	265,313.34	174,510.72	202,460.07		156,182.76		x	
0874000	Mains And Services	SEWERAMRP	Camera work due to AMRP pre and post jc	32,377.92	14,252.27	263.83		263.83			x
0874000	Mains And Services	TLVMGAS	Vegetation Management Mowing Total	398,252.79	462,271.69	380,926.89		227,537.88		x	
0874000	Mains And Services	874MNTLOC	Distr Maintenance Locates Total	45,297.69	12,400.59	35,360.32		55,962.97		x	
0874000	Mains And Services	CCEMC	Corrective action reads below .85V Total	5,610.30						x	
0874000	Mains And Services	EDGLS	Leak Survey on interval maps Total	319,881.03	305,136.88	325,895.44	517,756.72	441,010.88	517,756.72	x	
0874000	Mains And Services	GFACPROT	Damage prevention - Locates Total	208,730.98	288,466.20	289,525.00	77,601.89	225,017.30	77,601.89	x	
0874000	Mains And Services	GMOCM	Corrosion monitoring Total	246,121.91	241,434.13	42,147.55	206,753.38	120,060.30	206,753.38	x	
0874000	Mains And Services	GMOMP	Preventive maintenance on mains, etc. To	64,515.98	49,301.11	23,719.02				x	
0874000	Mains And Services	IMEXCDAM	Integrity Management Excavation Damages Total			37,663.13		56,991.51			x
0874000	Mains And Services	IMPNGO	Checking the integrity of mains Total	372,809.28	148,109.57	81,346.40	83,297.78	88,692.24	83,297.78		x
0874000	Mains And Services	PRESTEST	Pressure Test for MAOP Integrity Total	47,102.89							x
0875000	Measuring And Reg Stations-Ge	REGINSP	Regulator and System Station Inspections	3,935.48	166,241.97	135,558.86	175,733.97	167,240.62	175,733.97	x	
0875000	Measuring And Reg Stations-Ge	REGMC	Regulator and System Station Maintenance Corrective Total			0.00				x	
0875000	Measuring And Reg Stations-Ge	REGOSE	Regulator and System Station Pressure Adjust Total			0.00				x	
0876000	Measuring & Reg Station-Indus	CALIB	Meter & Reg Calibration of Meas Correctiv	26,393.81	59,203.43	16,898.30	1,685.19	3,150.37	1,685.19	x	
0878000	Meter And House Regulator Exp	878RELVAL	Inspection & testing of gas regulators and	4,637.66	22,836.13	28,120.38	24,722.36	15,640.40	24,722.36	x	
0878000	Meter And House Regulator Exp	INPIPEISP	INSIDE PIPING INSPECTION Total	56,226.04	42,864.89	814,241.13	217,608.18	560,713.03	217,608.18	x	
0878000	Meter And House Regulator Exp	RSCT	Compliance for regulator station calibratior	305.30	7,140.19	426.85				x	
0878000	Meter And House Regulator Exp	STRMAT879	Storeroom material 878 Total	9,940.20	18,555.50	14,987.01		6,903.87		x	
0879000	Customer Installation Expense	879HPINSP	GAS HOUSE PIPING INSPECT AND TEST				20,098.70	9,807.44	20,098.70	x	
0879000	Customer Installation Expense	879LEAKIN	Gas leak Investigations Total	702,293.58	608,390.51	745,240.91	528,407.15	618,098.94	528,407.15	x	
0879000	Customer Installation Expense	879REBLD	Making permanent gas leak repairs, gas s	131,649.62	88,187.72	338,614.22	111,893.67	145,022.75	111,893.67	x	
0879000	Customer Installation Expense	CORRISER	Corrosion Riser Total	12,937.24						x	
0879000	Customer Installation Expense	CUSTPREM	Work on customer premises investigating (	156,309.31	226,757.91	228,584.95	632,708.93	430,432.82	632,708.93	x	
0879000	Customer Installation Expense	MCSECM	Curb-main maintenance corrective Total	301.25						x	
0880000	Gas Distribution-Other Expense	887PUBAW	Public Awareness Total			0.00	29,950.92		29,950.92	x	
0880000	Gas Distribution-Other Expense	CPMANCON	CP Manager Total	15,426.40	9,363.29					x	
0880000	Gas Distribution-Other Expense	DIMPNGO	Distribution Integrity Mgt Total	36,319.34	125,685.47	132,503.93	670,868.68	419,270.49	670,868.68		x
0880000	Gas Distribution-Other Expense	GMOMP	Preventive maintenance on mains, etc. Total			0.00	44,143.12		44,143.12	x	
0880000	Gas Distribution-Other Expense	IM880PDM	Historical Pipeline Data Management Tota	1,267.28	3,497.40						x
0880000	Gas Distribution-Other Expense	IMRSKOPT	Int Mgmt Risk Optimain Total			105,367.71		35,089.91			x
0880000	Gas Distribution-Other Expense	LKREPOTH	Leak repair other Total		0.00		860,192.72		860,192.72	x	
0880000	Gas Distribution-Other Expense	MAOPCON	MAOP Verification / MAOP Calculator Tota	24,068.27	4,114.93						x
0880000	Gas Distribution-Other Expense	REGINSP	Regulator and System Station Inspections	125,025.99		0.00				x	
0880000	Gas Distribution-Other Expense	REGOSE	Regulator and System Station Pressure Ac	274.90		0.00	179,309.81		179,309.81	x	
0880000	Gas Distribution-Other Expense	TOLRPRG	Repair of equipment/tools/instruments Tot	3,223.54	2,207.33	14,588.09				x	
0880000	Gas Distribution-Other Expense	VALVCC	Inspetion of main valves code compliance	63,276.27	67,309.13	69,083.93	32,046.79	41,441.01	32,046.79	x	
0887000	Maintenance of Mains	887PUBAW	Public Awareness Total			54,997.42		63,654.66		x	
0887000	Maintenance of Mains	CCEMC	Corrective action reads below .85V Total	340,077.12	484,873.12	218,744.13		167,073.85		x	
0887000	Maintenance of Mains	CCEMP	orrosion Control Maintenance Preventative	5,442.18	5,535.43	5,569.22	136,386.48	5,928.15	136,386.48	x	
0887000	Maintenance of Mains	LKREPOTH	Leak repair other Total	503,089.45	686,933.87	510,343.99		669,572.27		x	
0887000	Maintenance of Mains	TOLRPRG	Repair of equipment/tools/instruments Total			0.00		2,463.70		x	
0887000	Maintenance of Mains	UNTNCORMN	Untonable Corr Maint on Main Total	50,709.28	4,497.30	274.66		274.66			x
0889000	Maint-Meas/Reg Stn Equip-Gas	GMOMP	Preventive maintenance on mains, etc. Total			0.00		35,756.38		x	
0889000	Maint-Meas/Reg Stn Equip-Gas	REGMC	Regulator and System Station Maintenanc	33,566.70	60,634.31	51,631.97	34,333.46	61,713.85	34,333.46	x	
0892000	Maintenance of Services	CBVISP	Curb Box Visual Inspection Program Total	656,904.92	705,477.52	537,997.66	644,153.71	363,386.00	644,153.71	x	
0892000	Maintenance of Services	MCSEMC	Existing M-C maintenance corrective Total	23,149.10	4,064.79	5,862.44	3,708.86	7,010.83	3,708.86	x	
0892000	Maintenance of Services	UNTNCORSV	Untonable Corr Maint on Services Total			122,399.59		126,079.51			x
0893000	Maint - Meters And House Reg	GMPAINT	Paint Gas meters & regulators Total	14,935.39	10,492.12	19,400.93		16,952.71		x	
0893000	Maint - Meters And House Reg	GMSREB	Test and repair of gas meters Total	200,830.05	89,981.68	99,509.39	8,199.91	59,600.14	8,199.91	x	
0893000	Maint - Meters And House Reg	GMTRINVOR	Investigating billing complaints, damaged (	84,673.68	81,912.16	82,843.53	9,288.66	58,552.41	9,288.66	x	
0930200	General Operational Expenses	930GENEXP	PHMSA Dues Total	8,403.25	12,119.90	8,886.75	12,000.00	12,000.00	12,000.00	x	
				5,445,728.83	5,928,892.58	6,194,485.18	6,037,389.46	6,120,539.30	6,037,389.46		

AG-DR-02-005

REQUEST:

Refer to the Company's response to Staff 2-33, which provides a history of the O&M expense incurred by the Company for its new CIS each year from 2018 through 2022.

a. Regarding the new CIS, provide the O&M expense that the Company considers developmental, including the implementation of each of the different modules/capabilities and in total, and the expense that the Company considers recurring post-development and post-implementation for each of different modules/capabilities, and in total, for each year 2018 through 2022 and forecast for 2023, by FERC O&M expense account/subaccount. In addition, describe the manner in which the Company made this determination, including a description of all accounting and tracking used to distinguish the expenses in this manner.

b. Regarding the old CIS, provide the O&M expense incurred by the Company each year from 2018 through 2022 and forecast for 2023 by FERC O&M expense account/subaccount.

RESPONSE:

a. Please see AG-DR-02-005(a) Attachment, pages 1-2, for the breakdown of O&M costs provided in response to Staff-DR-02-033 for costs incurred in 2018-2020. All of these costs are considered developmental costs and do not include any post-development costs. Please see AG-DR-02-005(a) Attachment, page 3, for the breakdown of O&M costs provided in response to STAFF-DR-02-033 for 2021 –

2022 as well as an estimate for 2023 between developmental costs and post-development ongoing costs.

b. Please see AG-DR-02-005(b) Attachment.

PERSON RESPONSIBLE: Retha I. Hunsicker

Duke Energy Kentucky Gas - TOTAL O&M Actuals 2018 - 2020

Release/Account	2018	2019	2020	Total
PROJECT RELEASES				
R5-8 Core Meter-to-Cash: 315986A - Core				***852,507.03***
0408960	4,059.84	2,703.93	3,970.64	10,734.41
0903000	242,383.01	226,609.94	310,839.80	779,832.75
0903100	(164.76)	(0.00)	6,873.14	6,708.38
0903200	(1,503.56)	0.00	5,936.04	4,432.48
0903300	(124.77)	0.00	4,783.16	4,658.39
0910100	-	-	4.36	4.36
0921100	(0.00)	(0.00)	58.76	58.76
0921200	(0.00)	-	7.39	7.39
0921400	-	-	395.87	395.87
0921540	-	0.00	8,390.73	8,390.73
0923000	-	-	3.13	3.13
0926000	-	32.41	157.92	190.33
0926420	-	0.49	9.49	9.98
0926600	13,127.28	9,171.48	14,781.31	37,080.07
R1 - Analytics & Data Marketing: 315986B - Analytics				***39,580.47***
0408960	762.35	-	-	762.35
0903000	37,953.19	-	-	37,953.19
0903200	(1,135.27)	-	-	(1,135.27)
0926600	2,000.20	-	-	2,000.20
R2 - Customer Engagement: 315986C - CRM				***177,935.18***
0408960	1,597.04	630.00	-	2,227.04
0903000	93,390.64	76,066.31	(58.70)	169,398.25
0903200	(822.49)	-	-	(822.49)
0926000	0.00	3.32	-	3.32
0926600	5,143.83	1,985.23	-	7,129.06
R3 - Customer Engagement: 315986D				***151,222.79***
0408960	672.27	871.96	37.70	1,581.93
0903000	56,847.55	86,146.61	1,293.17	144,287.33
0903200	(81.29)	-	-	(81.29)
0926600	2,376.69	2,934.65	123.48	5,434.82
R4 - Universal Bill: 315986E - Bill Format				***132,078.22***
0408960	309.99	1,144.95	1,006.26	2,461.20
0902000	-	-	25.00	25.00
0903000	19,721.28	65,455.90	35,825.51	121,002.69
0903100	-	-	8.56	8.56
0903200	(86.04)	-	8.10	(77.94)
0903300	-	-	6.47	6.47

Duke Energy Kentucky Gas - TOTAL O&M Actuals 2018 - 2020

Release/Account	2018	2019	2020	Total
0920100	-	-	7.32	7.32
0921400	-	0.00	94.21	94.21
0926600	1,138.70	3,901.96	3,510.05	8,550.71
CROSS RELEASE				
Hardware: 315986HW1				***20,635.39***
0903000	19,235.33	-	-	19,235.33
0935200	1,400.06	-	-	1,400.06
Hardware: 315986HW4				***3,038.25***
0903000	645.38	2,392.87	-	3,038.25
Hardware: 315986HW5				***876.65***
0903000	-	603.08	273.57	876.65
Hardware: 315986HW6				***2,447.75***
0903000	-	-	2,447.75	2,447.75
315986L: Customer Connect Leadership				***74,148.81***
0408960	871.80	923.41	936.08	2,731.29
0903000	19,474.83	21,019.95	21,570.19	62,064.97
0926600	2,887.12	3,027.50	3,437.93	9,352.55
315986OM: Program & Support				***206,414.68***
0408960	271.91	1,053.85	1,689.74	3,015.50
0417320			1,426.53	1,426.53
0903000	18,886.92	65,969.60	105,579.99	190,436.51
0903100	9.08	-		9.08
0903200	2.57	-		2.57
0903300	2.06	-		2.06
0912000	10.25	-		10.25
0920000	17.97			17.97
0921100	23.25	(0.00)	7.97	31.22
0921200	36.47	-		36.47
0921980	(7.07)			(7.07)
0923000	415.12	0.00	29.89	445.01
0926600	1,054.39	3,700.45	6,148.25	10,903.09
0930250	4.51			4.51
0935100	-	-	80.98	80.98
Miscellaneous				***7,767.78***
0408960	30.57	(2.25)	-	28.32
0903000	17.39	3,678.24	3,119.35	6,814.98
0903100	-	0.00	-	0.00
0920000	-	-	(72.09)	(72.09)
0921100	88.33	(0.00)	-	88.33
0926600	(1.96)	(7.07)	-	(9.03)
0935100	725.04	192.23		917.27
Grand Total	**543,667.00**	**580,211.00**	**544,775.00**	**1,668,653.00**

	2021*	2022	2023
DEK-Gas	953,238	1,901,576	335,182
Developmental Costs	953,238	1,901,576	145,492
Ongoing post-development costs	-	85,400	335,182
*Represents a combination of actuals and forecast	953,238	1,986,976	480,674

Note that project costs are not forecasted by FERC account; however most O&M costs are anticipated to be recorded to FERC account 0903.

	Actuals 2018	Actuals 2019	Actuals 2020	Actuals + Forecast* 2021	Forecast 2022	Forecast 2023	Total
KY Gas O&M Total - CMS Applications & Operations	$ 359,384	$ 312,846	$ 304,254	$ 255,706	$ 208,905	$ 42,912	$ 1,484,007

* The 2021 costs are actuals through June 2021

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-006

REQUEST:

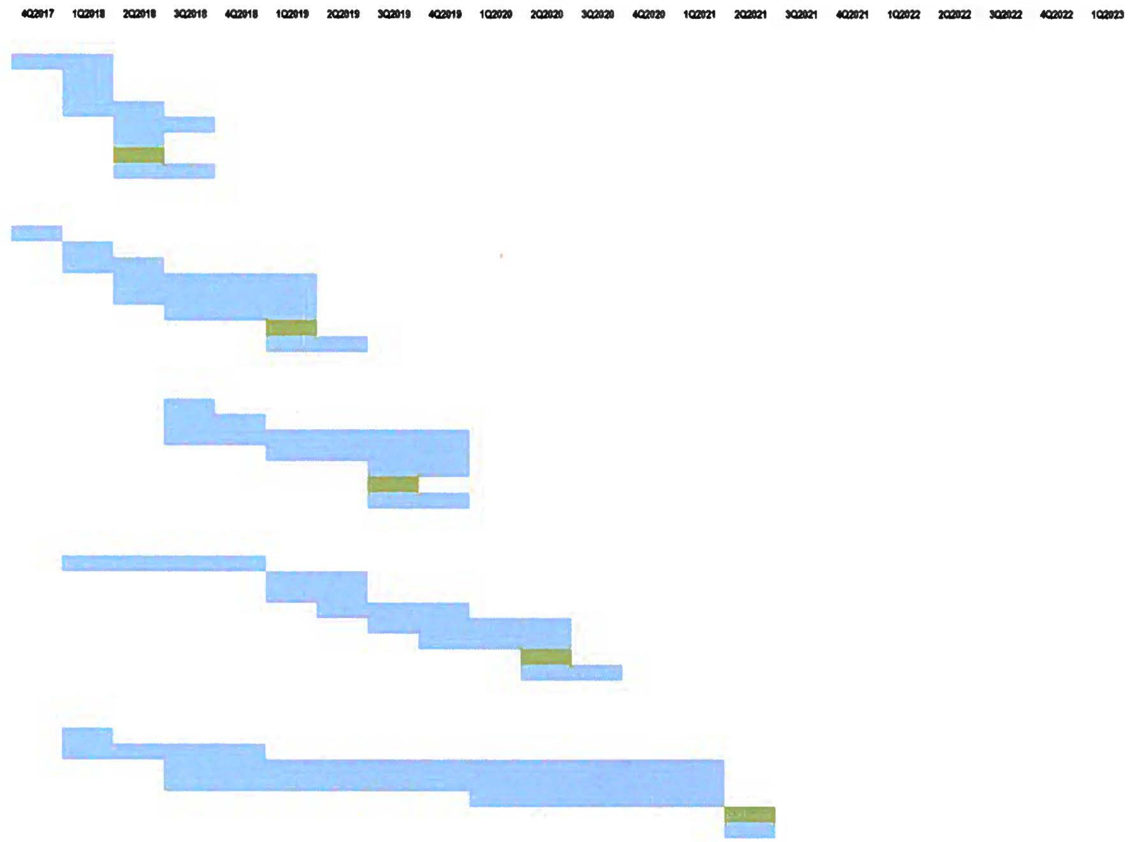
Provide a timeline showing the development and implementation (go live) dates for each of the different modules/capabilities of the new CIS from the beginning of the design process through the end of the test year, and through the completion of the development and implementation periods for all modules/capabilities.

RESPONSE:

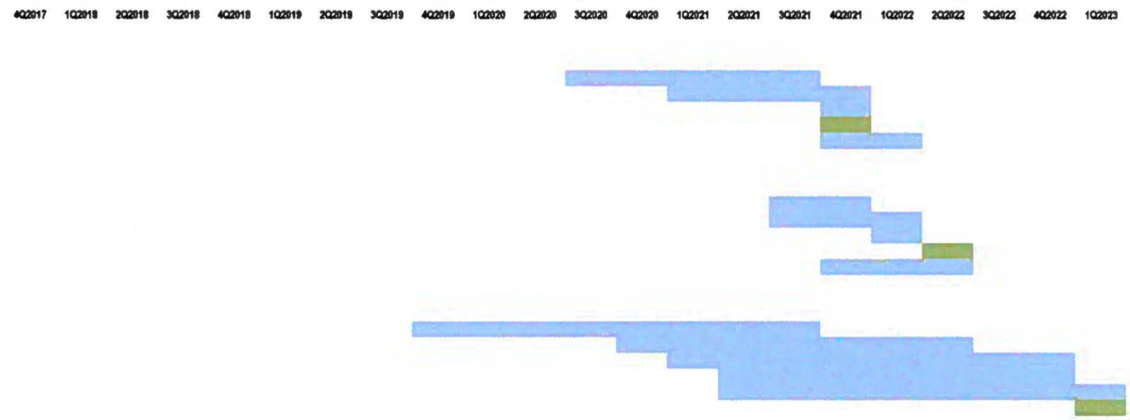
Please see AG-DR-02-006 Attachment.

PERSON RESPONSIBLE: Retha I. Hunsicker

Name	Start	Finish
Release 1 Plan		
Tasks	Mon 11/6/17	Fri 7/27/18
2017 Pre-Planning	Mon 11/6/17	Fri 1/12/18
Plan Phase	Tue 1/2/18	Fri 2/23/18
Initiate Phase	Tue 1/9/18	Fri 2/23/18
Design, Build, Validate Phase	Mon 1/22/18	Thu 5/10/18
Test and Service Introduction Phase	Mon 3/26/18	Thu 7/19/18
Deploy Phase	Mon 4/9/18	Tue 6/19/18
R1 Go Live	Mon 6/18/18	Mon 6/18/18
Warranty Phase	Thu 6/14/18	Fri 7/27/18
Release 2 Plan		
Tasks	Mon 11/6/17	Fri 5/17/19
2017 Pre-Planning	Mon 11/6/17	Fri 12/15/17
Plan Phase	Tue 1/2/18	Tue 3/6/18
Initiate Phase	Fri 1/26/18	Thu 6/7/18
Design, Build, Validate Phase	Fri 4/13/18	Fri 2/15/19
Test and Service Introduction Phase	Mon 4/16/18	Thu 2/28/19
Deploy Phase	Wed 8/15/18	Thu 2/28/19
R2 Go Live	Mon 2/18/19	Mon 2/18/19
Warranty Phase	Mon 2/18/19	Fri 5/17/19
Release 3 Plan		
Tasks	Mon 6/11/18	Fri 12/13/19
Plan Phase	Mon 6/11/18	Fri 9/7/18
Initiate Phase	Wed 8/1/18	Fri 12/14/18
Design, Build, Validate Phase	Wed 8/1/18	Fri 12/13/19
Test and Service Introduction Phase	Mon 3/25/19	Fri 11/22/19
Deploy Phase	Mon 6/10/19	Thu 10/31/19
R3 Go Live2 (2 deployments)	Mon 6/29/19	Mon 9/30/19
Warranty Phase	Mon 7/2/18	Fri 12/13/19
Release 4 Plan		
Tasks	Thu 2/1/18	Mon 7/27/20
Bill Format Design	Thu 2/1/18	Thu 12/13/18
Plan Phase	Wed 1/2/19	Fri 4/12/19
Initiate Phase	Thu 2/28/19	Fri 5/17/19
Design, Build, Validate Phase	Mon 4/15/19	Fri 12/6/19
Test and Service Introduction Phase	Mon 8/5/19	Tue 5/26/20
Deploy Phase	Thu 10/10/19	Tue 5/26/20
R4 Go Lives (4 deployments)	Mon 5/4/20	Mon 6/15/20
Warranty Phase	Mon 6/1/20	Mon 7/27/20
Release 5 Plan		
Tasks	Tue 1/2/18	Wed 9/22/21
Plan Phase	Tue 1/2/18	Thu 3/29/18
Initiate Phase	Mon 2/19/18	Mon 10/22/18
Design, Build, Validate Phase	Wed 8/15/18	Thu 3/11/21
Test and Service Introduction Phase	Mon 7/30/18	Tue 3/30/21
Deploy Phase	Wed 3/25/20	Tue 3/30/21
DEC Go Live	Mon 4/5/21	Mon 4/5/21
Warranty Phase	Tue 4/6/21	Tue 6/29/21



Name	Start	Finish
Release 6-7 Plan		
Tasks	Mon 8/31/20	Fri 1/28/22
Design, Build, Validate Phase	Mon 8/31/20	Tue 9/21/21
Test and Service Introduction Phase	Mon 2/15/21	Fri 10/8/21
Deploy Phase	Fri 10/15/21	Fri 11/5/21
DEF/DEP Go Live	Fri 11/5/21	Fri 11/5/21
Warranty Phase	Mon 11/8/21	Fri 1/28/22
Release 8 Plan		
Tasks	Mon 7/5/21	Wed 6/29/22
Design, Build, Validate Phase	Mon 7/5/21	Fri 11/5/21
Test and Service Introduction Phase	Mon 7/5/21	Fri 3/18/22
Deploy Phase	Thu 3/31/22	Wed 4/6/22
DEMW Go Live	Wed 4/6/22	Wed 4/6/22
Warranty Phase	Fri 12/3/21	Wed 6/29/22
System Retirement Plan		
Tasks	Mon 10/7/19	Fri 3/31/23
Plan Phase	Mon 10/7/19	Tue 8/24/21
Decommission Phase	Tue 11/17/20	Fri 5/27/22
Archive Phase	Mon 2/15/21	Fri 11/11/22
Dataview Phase	Mon 5/20/21	Tue 10/4/22
Retirement Phase	Wed 5/12/21	Mon 3/27/23
Retirements Complete	Fri 3/31/23	Fri 3/31/23



Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-007

REQUEST:

Provide a timeline showing the phase-out and retirement dates for each of the different modules/capabilities of the old CIS, compared to the timeline provided for the development and implementation of the new CIS provided in response to the immediately preceding question.

RESPONSE:

Please see AG-DR-02-006 Attachment.

PERSON RESPONSIBLE: Retha I. Hunsicker

AG-DR-02-008

REQUEST:

Refer to the Company's response to AG 1-14. Provide all supporting calculations for the $53,994 in an Excel spreadsheet in live format and with all formulas intact.

RESPONSE:

Please see AG-DR-02-008 Attachment, tabs "Sch-A" and "Sch B-2.3".

PERSON RESPONSIBLE: Jay P. Brown

AG-DR-02-008
ATTACHMENT

UPLOADED ELECTRONICALLY

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-009

REQUEST:

Refer to the Company's response to AG 1-19(a).

a. Provide a complete description of each work order.

b. Provide a schedule in the same format as the attachment showing total Duke Energy.

RESPONSE:

Please see AG-02-009(a) and (b) Attachments.

PERSON RESPONSIBLE: David G. Raiford – a.
Retha I. Hunsicker – b.

Work Order Number	Work Order Description	Description	Description
315986QC	CIS-Quality Center Licenses	Software	Quality Center software licenses purchased at the onset of the Customer Connect Project
315986A	Customer Connect - Core	Software	Software project for core-meter-to-cash solution for customers, including self-service and portals. Deployments completed for each jurisdiction
315986B	Customer Connect- Analytics	Software	Software project that enables advanced analytics capabilities to creat a #60 degree view of customers and predict customer journeys
315986C	Customer Connect- Release 2	Software	Software projects that enables capability to leverage comprehensive data about customers to create more meaningful interactions
315986D	Customer Connect- Release 3	Software	
315986E	Customer Connect- Universal Bill	Software	Project for new universal bill format for all customers to more easily view and understand their bill
315986F	Customer Connect - R6-8 Scope	Software	Software project for core-meter-to-cash solution for customers, including self-service and portals. Deployments completed for each jurisdiction
315986HW1	Customer Connect- Hardware Proj 1	Hardware	Hardware purchases such as servers and other equipment purchased as required for the Customer Connect project. Hardware has been purchased and placed in service throuhg the duration of the project.
315986HW4	Customer Connect- Hardware Proj 2	Hardware	
315986HW5	Customer Connect- Hardware Proj 3	Hardware	
315986HW6	Customer Connect- Hardware Proj 4	Hardware	
315986HW7	Customer Connect - Hardware Proj 5	Hardware	

Work Order Number	Work Order Description	Component	Utility Account	2016	2017	2018	2019	2020	2021 Act+FCAST	Forecast 2022	Expected total Project Cost
315986QC	CIS-Quality Center Licenses	Software	20300 - Miscellaneous Intangible Pl	200,008	(344)	-	-	-	-	-	**199,664**
315986A	Customer Connect - Core	Software	20300 - Miscellaneous Intangible Pl	-	20,381,187	11,720,563	91,782,376	107,479,266	95,130,872	30,539,620	**357,033,885**
315986B	Customer Connect- Analytics	Software	20300 - Miscellaneous Intangible Pl	-	2,499,942	6,192,024	(2,360)	-	-	-	**8,689,607**
315986C	Customer Connect- Release 2	Software	20300 - Miscellaneous Intangible Pl	-	2,715,229	14,426,709	6,963,686	411,697	-	-	**24,517,321**
315986D	Customer Connect- Release 3	Software	20300 - Miscellaneous Intangible Pl	-	5,832,870	2,407,714	7,305,293	32,757	-	-	**15,578,634**
315986E	Customer Connect- Universal Bill	Software	20300 - Miscellaneous Intangible Pl	-	4,205,827	779,174	7,446,723	6,711,082	218,421	70,472	**19,431,699**
315986F	Customer Connect - R6-8 Scope	Software	20300 - Miscellaneous Intangible Pl	-	-	-	-	-	7,181,641	5,262,406	**12,444,046**
315986HW1	Customer Connect- Hardware Proj 1	Hardware	29101 - Electronic Data Processing	-	5,275,412	8,277,183	10,410	-	-	-	**13,563,005**
315986HW4	Customer Connect- Hardware Proj 2	Hardware	29101 - Electronic Data Processing	-	-	5,615,580	5,186,212	0	-	-	**10,801,792**
315986HW5	Customer Connect- Hardware Proj 3	Hardware	29101 - Electronic Data Processing	-	-	-	5,226,075	1,015,650	-	-	**6,241,725**
315986HW6	Customer Connect- Hardware Proj 4	Hardware	29101 - Electronic Data Processing	-	-	-	-	4,743,783	-	-	**4,743,783**
315986HW7	Customer Connect - Hardware Proj 5	Hardware	29101 - Electronic Data Processing	-	-	-	-	-	8,364,044	2,741,200	**11,105,244**
		AFUDC		641	542,833	2,442,768	6,443,628	11,095,551	11,110,046	2,458,472	**34,093,938**
				200,649	**41,452,956**	**51,861,716**	**130,362,044**	**131,489,784**	**122,005,024**	**41,072,170**	**518,444,343**

AG-DR-02-010

REQUEST:

Refer to the Company's response to AG 1-19(d), which shows the capital expenditures and O&M expense for the new CIS each year from 2016 through 2023 on a total Duke Energy basis.

a. Provide a similar table that provides the DEK share of the total Duke Energy amounts.

b. Provide a similar table showing the actual capital expenditures and O&M expenses each year through 2020, each month through 2021, and the budget/forecast amounts for each remaining month in 2021, each month during the test year and in 2023 on a total Duke Energy basis.

c. Provide a similar table that provides the DEK share of the total Duke Energy amounts provided in response to part (b) of this question.

d. Provide an estimate/forecast of the "steady state" ongoing O&M expense for the new CIS for each of the different modules/capabilities, and in total after each module/capability goes live on an annualized basis. Provide all supporting documentation and calculations in live format with all formulas intact in support of these estimates/forecasts.

e. Provide the depreciation expense, including all details of the calculations, included in the test year for each of the new CIS modules/capabilities included in the test year. Provide the calculations in Excel live format with all formulas intact. Provide the calculations of the depreciation rates in Excel live format with all formulas intact. Provide the life spans used for this purpose and describe each deviation from the life spans set forth in the response to AG 1-19(d).

f. Explain why the Company is using and proposes specific life spans for the new CIS compared to simply using the depreciation rates developed using the December 2017 plant balances in the last depreciation study.

g. Provide the actual life spans of the old CIS that serve/served DEK, including the date(s) of major upgrades or replacements of some or all of the modules/capabilities. Describe the actual upgrades and replacements of any of the modules/capabilities.

RESPONSE:

a. AG-DR-01-019(d) Attachment was provided in response to the question: "Provide the estimated life span of the new CIS system and <u>all support</u> for this life span." This attachment was the memo created in 2017 <u>supporting</u> those depreciable lives. The data in the table was prepared at that time and has been subsequently revised. Capital and O&M for Duke Energy Kentucky's new customer connect system has been provided in response to AG-DR-01-019(a) and STAFF-DR-02-033.

b. See response to AG-DR-02-009(b) Attachment.

c. See response (a) above.

d. See response to AG-DR-02-005.

e. See AG-DR-01-019(e) Attachment, Line 8 for depreciation expense. See response (a) above for life spans.

f. Software amortization is not part of the depreciation study, as software is considered intangible plant that is individually amortized over the useful life of the asset.

g. The Company's old CIS was placed in service in 2003 and has been fully depreciated on the books and records since 2013. As follows are upgrades that have since been made to the existing CIS.

Capability	Description	Date Implemented	Expected Life
Proactive Outage Alerts	Outage alerts via text and voice	Nov. 2015	5 years
Proactive Communications	Outage alerts via email; non-payment messages (disconnect and reconnect)	Mar. – Aug. 2016	5 years
Proactive Communications	Automated outage information including crew status and outage cause	Dec. 2019	5 years
Track My Service Messages	Start and Stop Service Confirmations	Sept. 2018-Feb 2019	5 years
Pick Your Due Data Program	Allow customers with AMI meters to select their bill due date within the month	Nov. 2016	5 years
Payment Confirmations	Text or email confirmation of customer payment	Nov. 2017	5 years

PERSON RESPONSIBLE: David G. Raiford
Retha I. Hunsicker
Jay P. Brown

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-011

REQUEST:

Provide the average service life for the 2017 vintage year plant for each plant account and subaccount included in the 2017 depreciation study provided as Exhibit JJS-1 attached to Mr. Spanos' testimony in this proceeding.

RESPONSE:

The standard practice for calculating depreciation by account is through group depreciation. Exhibit JJS-1 in the 2017 depreciation study establishes survivor curves by account which is a combination of the average service life and mortality curve for each account. The survivor curve is presented on pages VI-4 and VI-5, column 2 of Exhibit JJS-1. The statistical analysis of the service life considerations is also presented in Part VII of Exhibit JJS-1. For example, the survivor curve for Account 2761 is 47-R2.5 which means the average service life for the account is 47 years.

If the request is asking for the average remaining life or vintage remaining life for each account then please see Part IX, column 6 of each account in Exhibit JJS-1.

PERSON RESPONSIBLE: John J. Spanos
David G. Raiford

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-012

REQUEST:

Provide the average service life for the 2016 vintage year plant for each plant account and subaccount included in the 2017 depreciation study provided as Exhibit JJS-1 attached to Mr. Spanos' testimony in this proceeding.

RESPONSE:

Please see response to AG-DR-02-011.

PERSON RESPONSIBLE: John J. Spanos
David G. Raiford

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-013

REQUEST:

Provide the average service life for the 2015 vintage year plant for each plant account and subaccount included in the 2017 depreciation study provided as Exhibit JJS-1 attached to Mr. Spanos' testimony in this proceeding.

RESPONSE:

Please see response to AG-DR-02-011.

PERSON RESPONSIBLE: John J. Spanos
David G. Raiford

AG-DR-02-014

REQUEST:

Refer to the Company's response to AG 1-18.

a. Provide the Company's capital expenditures by month from January 2018 through December 2022.

b. Provide the Company's non-gas O&M expense and other non-gas non-depreciation expense by month from January 2018 through December 2022.

c. Refer also to the Company's response to AG 1-13, which provides a trial balance. Included in the trial balance is account 232996, which appears to be an account used by the Company for its construction (capital) accounts payable accruals.

   i. Confirm that the Company records its accounts payable for construction with a debit to CWIP or some other asset account and a credit to accounts payable.

   ii. Confirm that the Company records its accounts payable for construction to account 232996. If this is not correct, then provide the correct account.

   iii. Provide the monthly accounts payable to construction for the Company's natural gas assets and share of common assets by month from January 2018 through the most recent month available.

d. Confirm that the Company records its accounts payable for operating expenses with a debit to the expense account and a credit to accounts payable.

e. Is it the Company's position that it cannot query its general ledger system at month end as to the outstanding accounts payable offset by CWIP and the accounts payable offset by operating expenses? If it is, then explain why it cannot obtain this information. If this is not the Company's position, then provide the information requested in AG 1-18.

RESPONSE:

a. See AG-DR-02-014 Attachment for gas capital spend by month for the actual periods January 2018-February 2021 and forecasted data for March 2021-December 2022. Note, this represents total gas capital spend and not gas plant in service balances. Additionally, note that amounts exclude AFUDC.

b. Objection. This request is vague, ambiguous, overbroad, unduly burdensome and seeks information that is irrelevant to this proceeding. If "other non-gas non depreciation expense" is another way to define electric expenses, this information is available in Duke Energy Kentucky's annual FERC Form 1 filings.

c.

    i. Confirmed.

    ii. Accounts payable for construction is recorded to Account 0232016 when invoices are approved for payment in CAPS, our Accounts Payable System. Account 0232996 is only used for manual accounts payable accruals.

    iii. Company records are not maintained in a manner to determine the amounts requested.

d. Confirmed.

e. Company records are not maintained in a manner to determine the offsets to outstanding accounts payable at month end.

PERSON RESPONSIBLE: Bryan T. Manges
Abby L. Motsinger

	Amount
Jan-18	714,307
Feb-18	5,483,840
Mar-18	6,672,231
Apr-18	6,455,114
May-18	4,553,986
Jun-18	4,218,750
Jul-18	1,936,722
Aug-18	12,519,800
Sep-18	5,440,540
Oct-18	9,051,953
Nov-18	8,055,337
Dec-18	7,731,814
2018 Total	72,834,395
Jan-19	5,758,926
Feb-19	5,203,015
Mar-19	574,198
Apr-19	6,452,151
May-19	7,889,702
Jun-19	9,157,515
Jul-19	8,622,452
Aug-19	7,872,993
Sep-19	9,973,058
Oct-19	14,436,803
Nov-19	9,367,468
Dec-19	3,994,029
2019 Total	89,302,309
Jan-20	4,732,177
Feb-20	5,458,060
Mar-20	5,590,905
Apr-20	4,357,364
May-20	7,314,939
Jun-20	13,939,034
Jul-20	7,942,184
Aug-20	6,270,935
Sep-20	7,669,608
Oct-20	8,247,231
Nov-20	3,632,206
Dec-20	5,120,735
2020 Total	80,275,378

	Amount
Jan-21	4,946,573
Feb-21	1,213,774
Mar-21	3,916,416
Apr-21	4,079,970
May-21	4,920,219
Jun-21	5,074,510
Jul-21	5,534,246
Aug-21	7,376,718
Sep-21	8,536,928
Oct-21	8,725,348
Nov-21	6,204,070
Dec-21	4,952,066
2021 Total	65,480,838
Jan-22	4,538,204
Feb-22	4,549,381
Mar-22	4,708,008
Apr-22	4,506,991
May-22	4,704,963
Jun-22	4,904,867
Jul-22	4,569,447
Aug-22	5,266,194
Sep-22	5,409,883
Oct-22	5,787,105
Nov-22	5,625,972
Dec-22	5,663,052
2022 Total	60,234,068

Note that amounts exclude AFUDC.

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-015

REQUEST:

Provide the pension expense reflected in the test year separately for DEK, allocated from DEO, and allocated from DEBS. Provide the actuarial report relied on for these amounts and annotate the amount included in the revenue requirement to the actuarial report, including the allocations of DEO and DEBS amounts to DEK, jurisdictional allocations, and allocations of total cost to the expense reflected in the test year.

RESPONSE:

Pension expense reflected in test year for DEK is ($584,712).

Pension expense reflected in test year allocated from DEO is $87,912.

Pension expense reflected in test year allocated from DEBS is $788,516.

The actuarial report was previously provided as a response to question AG-DR-01-040.

PERSON RESPONSIBLE: Jake J. Stewart
Jay P. Brown

AG-DR-02-016

REQUEST:

Provide the OPEB expense reflected in the test year separately for DEK, allocated from DEO, and allocated from DEBS. Provide the actuarial report relied on for these amounts and annotate the amount included in the revenue requirement to the actuarial report, including the allocations of DEO and DEBS amounts to DEK, jurisdictional allocations, and allocations of total cost to the expense reflected in the test year.

RESPONSE:

OPEB expense reflected in the test year is as follows:

DEK	$462,773
Allocated from DEO	$ 4,477
Allocated from DEBS	$ 29,003

Detailed calculation for OPEB expense reflected in the test year, including components of calculation based on actuarial report, is as follows:

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	DEK	DEBS	DEO
Net periodic benefit cost - service cost (A)	$ 72,842	$ 974,103	$ 188,246
O&M percentage	68.05%	72.42%	47.38%
Percent DEBS allocation to DEK		4.22%	
Percent DEO allocation to DEK			5.02%
Expense O&M	49,569	29,770	4,477
Net periodic benefit cost - non-service cost (B)	245,386	(49,807)	-
Purchase accounting amortization	167,818		
Subtotal	413,204	(49,807)	-
Percent DEBS allocation to DEK		1.54%	
Total	413,204	(767)	-
Total OPEB Expense (to above)	$ 462,773	$ 29,003	$ 4,477

A Please refer to the 'Service Cost" line within the "OPEB" tab of actuarial report, provided in response to AG-DR-01-040 (AG-DR-01-040 CONF Attachment.xls).

B Please refer to the "Other" line within the "OPEB" tab of actuarial report, provided in response to AG-DR-01-040 (AG-DR-01-040 CONF Attachment.xls).

PERSON RESPONSIBLE: Jake J. Stewart
Jay P. Brown

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-017

REQUEST:

Refer to the Company's response to AG 1-41. Confirm that the Company did not remove the employer 401(k) match for employees who also participate in the defined benefit plan. If this is not correct, then provide a correct statement and indicate where this expense was removed.

RESPONSE:

The Company did not remove employer 401(k) match for employees who also participate in the defined benefit plan. The 401(k) plan is now our standard retirement plan that applies to all union and non-union new hires. Duke Energy has taken significant steps to both control costs and reduce the risk associated with its retirement plans by eliminating the pension benefit for all new hires, including union new hires, and moving all non-union pension eligible employees and the majority of union pension eligible employees to a cash balance design. In Case No. 2019-00271, to address the Commission's concerns around the expense for employees receiving both a pension benefit and a 401(k)-retirement benefit, the Company made a proforma adjustment to remove the pension cost for employees who also receive 401(k) match. However, in this rate case, pension expense for employees receiving both a pension benefit and a 401(k)-retirement benefit in the test period is a net credit of ($287,880). In this proceeding it benefits customers to not include a proforma adjustment to remove the pension cost for employees who also receive 401(k) match since doing so would increase the test year revenue requirement.

PERSON RESPONSIBLE: Jay P. Brown

AG-DR-02-018

REQUEST:

Refer to the Company's response to AG 1-60. Confirm that the Company did not remove the SERP expense in conjunction with its adjustments to remove incentive compensation tied to financial metrics. If this is not correct, then provide a correct statement and indicate where this expense was removed.

RESPONSE:

The Company did not remove SERP expense.

PERSON RESPONSIBLE: Jay P. Brown

PUBLIC AG-DR-02-019

REQUEST:

Refer to the Company's response to AG 1-66.

a. Provide the requested copy of all documentation that addresses the capitalization or expensing of costs to install or remove assets, including retirements and cost of removal charged to the accumulated depreciation reserve or expensed as maintenance.

b. Provide a detailed description of the Company's accounting when it retires assets and replaces them with new assets, including the methodology it uses to allocate or otherwise determine the payroll and related costs allocated to the additions versus the retirements for cost of removal.

c. Provide a detailed description of the Company's guidelines and practices for the physical removal of assets by type of plant (pipeline, regulator, service, etc.) or whether they are left in place. For example, most utilities do not remove old pipeline when it is retired, at least longer sections, instead cutting and bypassing the old pipeline when a section is replaced.

d. Provide a copy of the most recent Time and Motion study or other study used by DEK in the determination of net salvage percentages or amounts to be written off when an existing asset is replaced with a new asset.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment (a) only)</u>

a. Please see AG-DR-02-019(a) Confidential Attachment. Basic Capitalization Guidelines are outlined on page 32, O&M activities are discussed on page 36. Cost of Removal is addressed on page 126.

b. Page 126 of the Capitalization Policy discusses cost of removal guidance and cost of removal allocation guidance. Page 154 of the Capitalization Policy discusses retirement project guidelines as well as the FERC accounting guidance related to retirements

c. The Company does not have official field procedures on the actual retirement of assets, but the practice has typically been to purge, cut, cap and abandon mains in place. Above ground facilities such as stations would typically be removed, which also include the associated underground piping.

d. Net Salvage percentages are developed as part of a depreciation study conducted by an external consultant. Please see AG-DR-02-019(d) Attachment which reflects the net salvage rates developed in the 2017 depreciation study that was approved in the 2018 DEK Gas Rate Order 20081-00261. Net Salvage is determined by taking Gross Salvage amounts recorded for a particular asset group and subtracting Cost of Removal incurred for the same group. A negative net salvage would indicate that cost of removal is higher than any salvage proceeds the Company expects to receive. Assets are retired when they are replaced, and net salvage does not impact how the assets are retired or replaced. When an asset is retired, the gross value of the asset, (the amount that is recorded to Account 101, Plant in Service), is removed (credited) from 101 and the debit is recorded to 108, Accumulated Depreciation

Reserve. Retired assets are not “written off” through the income statement in most cases.

PERSON RESPONSIBLE: David G. Raiford

CONFIDENTIAL PROPRIETARY TRADE SECRET

AG-DR-02-019 CONFIDENTIAL ATTACHMENT (a) pdf

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DUKE ENERGY KENTUCKY
GAS PLANT

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2017

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2017	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	PRODUCTION PLANT								
2041	RIGHTS OF WAY	50-SQ *	0	24,458.90	24,439	20	4	0.02	5.0
2050	STRUCTURES AND IMPROVEMENTS	55-R4 *	(10)	1,722,763.66	1,419,183	475,857	80,887	4.70	5.9
2110	LIQUEFIED PETROLEUM GAS EQUIPMENT	55-R2.5 *	(10)	5,955,198.20	2,977,438	3,573,280	527,625	8.86	6.8
	TOTAL PRODUCTION PLANT			**7,702,420.76**	**4,421,060**	**4,049,157**	**608,516**	**7.90**	**6.7**
	DISTRIBUTION PLANT								
2741	RIGHTS OF WAY	70-R4	0	1,095,119.18	642,232	452,887	11,381	1.04	39.8
2750	STRUCTURES AND IMPROVEMENTS	60-R2	(5)	555,988.27	145,936	437,851	7,995	1.44	54.8
	MAINS								
2761	CAST IRON, COPPER AND ALL VALVES	47-R2.5	(20)	982,749.37	(122,219)	1,301,518	85,500	8.70	15.2
2762	STEEL	65-R2.5	(20)	83,504,429.58	39,512,552	60,692,763	1,373,621	1.64	44.2
2763	PLASTIC	70-R3	(20)	149,291,612.99	47,525,256	131,624,679	2,279,170	1.53	57.8
2765	STEEL FEEDER LINES	65-R2.5	(20)	34,279,326.54	15,918,386	25,216,805	509,068	1.49	49.5
	TOTAL MAINS			268,058,118.48	102,833,976	218,835,765	4,247,359	1.58	
2780	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	52-R1.5	(25)	6,402,913.06	2,338,883	5,664,759	130,926	2.04	43.3
2781	MEASURING AND REGULATING STATION EQUIPMENT - ELECTRONIC	25-S2	(25)	1,136,972.88	495,731	925,485	72,375	6.37	12.8
2782	MEASURING AND REGULATING STATION EQUIPMENT - DISTRICT	55-R2	(25)	2,302,852.69	1,014,222	1,864,343	37,922	1.65	49.2
	SERVICES								
2801	CAST IRON, COPPER AND ALL VALVES	40-R2	(25)	3,529,256.01	515,332	3,896,238	186,127	5.27	20.9
2802	STEEL	42-R2	(25)	8,822,095.39	2,270,659	8,756,960	294,302	3.34	29.8
2803	PLASTIC	48-S0.5	(25)	146,553,942.78	45,265,564	137,926,864	3,500,301	2.39	39.4
	TOTAL SERVICES			158,905,294.18	48,051,556	150,580,062	3,980,730	2.51	
2810	METERS	17-L0	0	14,160,599.88	(4,098,109)	18,258,709	1,524,720	10.77	12.0
2820	METER INSTALLATIONS	30-S0	0	10,424,840.45	2,316,474	8,108,367	398,018	3.82	20.4
2830	HOUSE REGULATORS	42-R1.5	0	6,650,479.43	2,104,614	4,545,865	142,834	2.15	31.8
2840	HOUSE REGULATOR INSTALLATIONS	50-R3	0	5,816,407.30	2,351,040	3,465,368	92,360	1.59	37.5
2850	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	42-R2	(10)	455,084.24	425,708	74,885	2,712	0.60	27.6
2851	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT - ELECTRONIC	25-R2.5	(10)	64,790.82	47,089	24,181	2,361	3.64	10.2
2870	OTHER EQUIPMENT	17-R3	0	21,446.76	22,692	(1,245)	0	-	-
2871	STREET LIGHTING EQUIPMENT	35-S2.5	0	28,290.11	20,415	7,875	497	1.76	15.8
	TOTAL DISTRIBUTION PLANT			**476,079,197.73**	**158,712,459**	**413,245,157**	**10,652,190**	**2.24**	**38.8**
	GENERAL PLANT								
2910	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	13,861.47	13,921	(60)	0	- **	-
2911	OFFICE FURNITURE AND EQUIPMENT - ELECTRONIC DATA PROCESSING	5-SQ	0	310,654.92	75,511	235,144	71,308	22.95	3.3
2921	TRANSPORTATION EQUIPMENT - TRAILERS	14-R1.5	5	65,845.27	64,371	(1,818)	0	- **	-
2940	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	1,278,772.08	724,896	553,876	60,153	4.70	9.2
2970	COMMUNICATION EQUIPMENT	15-SQ	0	2,830,460.27	60,972	2,769,488	191,441	6.76	14.5
2980	MISCELLANEOUS EQUIPMENT	20-SQ	0	83,590.71	22,886	60,704	11,037	13.20	5.5
	TOTAL GENERAL PLANT			**4,583,184.72**	**962,558**	**3,617,334**	**333,939**	**7.29**	**10.8**
	TOTAL DEPRECIABLE PLANT			**488,364,803.21**	**164,096,076**	**420,911,648**	**11,594,645**	**2.37**	**36.3**
	NONDEPRECIABLE AND ACCOUNTS NOT STUDIED								
2030	MISCELLANEOUS INTANGIBLE PLANT			8,728,213.74	4,717,583				
2031	MISCELLANEOUS INTANGIBLE PLANT - 10-YEAR			2,551,238.23	82,444				
2040	LAND AND LAND RIGHTS			117,711.07					
2740	LAND AND LAND RIGHTS			43,358.14	4				
	TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED			**11,440,521.18**	**4,800,031**				
	TOTAL GAS PLANT			**499,805,324.39**	**168,896,107**	**420,911,648**	**11,594,645**		

* LIFE SPAN PROCEDURE WAS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.
** NEW ADDITIONS AFTER JANUARY 1, 2018 WILL HAVE THE FOLLOWING RATES:

ACCOUNT	RATE
2910 OFFICE FURNITURE AND EQUIPMENT	5.00
2921 TRANSPORTATION EQUIPMENT - TRAILERS	6.99

NOTE: ADDITIONS FOR NEW ACCOUNTS AFTER JANUARY 1, 2018 SHOULD USE THE FOLLOWING RATES:

ACCOUNT	RATE
2920 TRANSPORTATION EQUIPMENT	8.70
2960 POWER OPERATED EQUIPMENT	6.90

AG-DR-02-020

REQUEST:

Refer to the Sch_C2.1 - Base Period and Sch_C2.1 - Forecasted Period tabs in STAFF-DR-01-054_Attachment_-_KPSC_GAS_SFRs-2021. Explain why the Company's forecast test year Account 489020 Commercial Gas Transportation in the test year is $1.379 million compared to $1.498 million in the base year. Describe all reasons why the Company forecasts a reduction in these revenues in the test year, especially when the Company forecasts significant increases in the test year Account 489030 Industrial Gas Transportation and Account 489040 OPA Gas Transportation compared to the base year. What is unique about Commercial Gas Transportation compared to the other transportation revenue accounts?

RESPONSE:

The main reason a decrease in revenues is anticipated for the commercial class is a projected decrease in volumes. The principal economic driver for sales to commercial customers is employment, and stronger-than expected job growth during 2021 has accompanied the recent surge in sales. As the economy re-approaches its pre-pandemic output level, that hiring will slow, implying a slowdown in sales projected by the model.

An upwards adjustment to Industrial sales was made for a new, large customer that is being added to the system, and that customer's volumes were allocated between Full Service and Transportation at the same proportion as the rest of industrial sales. The OPA class was more dramatically affected during the historical period for model estimation because of COVID-motivated school closures, so there is some rebound anticipated there as well.

PERSONS RESPONSIBLE: Abby L. Motsinger
Benjamin W. Passty

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-021

REQUEST:

Refer to the Sch_J3 – Forecast tab in STAFF-DR-01-054_Attachment_-_KPSC_GAS_SFRs-2021. Provide a version of this spreadsheet with all formulas intact, specifically, with all column M calculations instead of the values in the version provided in response to Staff 1-54.

RESPONSE:

Please see STAFF-DR-02-021 Attachment.

PERSON RESPONSIBLE: Chris R. Bauer

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2021-00XYZ
EMBEDDED COST OF LONG-TERM DEBT
THIRTEEN MONTH AVERAGE BALANCE ENDING DECEMBER 31, 2022
(CORPORATE)

DATA: BASE PERIOD "X" FORECASTED PERIOD
DATE OF CAPITAL STRUCTURE: END OF FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

SCHEDULE J-3
PAGE 2 OF 2
WITNESS RESPONSIBLE:
C. BAUER

LINE NO.	DEBT ISSUE TYPE, COUPON RATE			DATE ISSUED (DAY/MO/YR) (A)	MATURITY DATE (DAY/MO/YR) (B)	PRINCIPAL AMOUNT (C)	FACE AMOUNT OUTSTANDING (D)	UNAMORT. (DISCOUNT) OR PREMIUM (E)	UNAMORT. DEBT EXPENSE (F)	UNAMORT. LOSS ON REACQUIRED DEBT (G)	CARRYING VALUE (H=D+E-F-G)	ANNUAL INTEREST COST(*) (I)
						($)	($)	($)	($)	($)	($)	($)
1	Unamortized Loss on Reacquired Debt											
2												
3	7.65% due 7/15/2025									194,299	(194,299)	63,938
4	5.5% due 1/1/2024									57,980	(57,980)	38,654
5	6.5% due 1/15/2022									-	-	2,102
6	Variable rate PCB, due 8/1/2027									82,634	(82,634)	15,569
7												
8	Other Long Term Debt											
9	LT Commercial Paper	0.541%	Series		16-Mar-26	25,000,000	25,000,000	-	-	-	25,000,000	135,133
10	Debentures	3.860%	Series	26-Jul-06	01-Aug-27	26,720,000	26,720,000	-	101,255	-	26,618,745	1,051,311
11	Debentures	Variable	Series	03-Dec-08	01-Aug-27	50,000,000	50,000,000	-	127,000	-	49,873,000	681,713
12	Debentures	6.200%	Series	10-Mar-06	10-Mar-36	65,000,000	65,000,000	(167,905)	298,278	-	64,533,817	4,064,049
13	Debentures	3.420%	Series	05-Jan-16	15-Jan-26	45,000,000	45,000,000	-	84,265	-	44,915,735	1,562,811
14	Debentures	4.450%	Series	05-Jan-16	15-Jan-46	50,000,000	50,000,000	-	208,694	-	49,791,306	2,233,866
15	Debentures	3.350%	Series	07-Sep-17	15-Sep-29	30,000,000	30,000,000	-	74,605	-	29,925,396	1,015,354
16	Debentures	4.110%	Series	07-Sep-17	15-Sep-47	30,000,000	30,000,000	-	104,505	-	29,895,495	1,237,146
17	Debentures	4.260%	Series	07-Sep-17	15-Sep-57	30,000,000	30,000,000	-	109,494	-	29,890,506	1,281,110
18	Debentures	4.010%	Series	03-Oct-18	15-Oct-23	25,000,000	25,000,000	-	28,558	-	24,971,442	1,024,657
19	Debentures	4.180%	Series	03-Oct-18	15-Oct-28	40,000,000	40,000,000	-	98,108	-	39,901,892	1,687,600
20	Debentures	4.620%	Series	12-Dec-18	15-Dec-48	35,000,000	35,000,000	-	124,767	-	34,875,233	1,621,716
21	Debentures	4.320%	Series	17-Jul-19	15-Jul-49	40,000,000	40,000,000	-	176,990	-	39,823,010	1,734,546
22	Debentures	3.230%	Series	26-Sep-19	01-Oct-25	95,000,000	95,000,000	-	224,317	-	94,775,683	3,137,521
23	Debentures	3.560%	Series	26-Sep-19	01-Oct-29	75,000,000	75,000,000	-	242,598	-	74,757,402	2,703,462
24	Debentures	2.650%	Series	15-Sep-20	15-Sep-30	35,000,000	35,000,000	-	104,443	-	34,895,557	940,228
25	Debentures	3.660%	Series	15-Sep-20	15-Sep-50	35,000,000	35,000,000	-	119,670	-	34,880,330	1,285,243
26	Future Debentures	3.686%	Series	15-Sep-21	15-Mar-42	50,000,000	50,000,000	-	144,817	-	49,855,183	1,850,351
27	Future Debentures	3.896%	Series	15-Sep-22	15-Mar-43	70,000,000	21,538,462	-	48,166	-	21,490,296	841,473
28												
29	MCF Fees			-	16-Mar-25	-	-	-	242,766	-	(242,766)	89,637
30	LOC Fees				14-Feb-23	-	-	-	7,067	-	(7,067)	11,409
31	Other fees ($26.720M - remarketing, insurance, Bilateral LC)											449,011
32												
33	Current Maturities											
34	Debentures	4.010%	Series	03-Oct-18	15-Oct-23		(5,769,231)		(4,460)		(5,764,771)	(236,459)
35												
36			Totals			851,720,000	797,489,231	(167,905)	2,665,901	334,914	794,320,511	30,523,149
37												
38												
39			Embedded Cost of Long-Term Debt (I / H)									3.843%

(*) Annualized interest cost plus (or minus) amortization of discount or premium plus amortization of issue costs minus (or plus) amortization of gain (or loss) on reacquired debt.

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2021-00XYZ
EMBEDDED COST OF LONG-TERM DEBT
THIRTEEN MONTH AVERAGE BALANCE ENDING DECEMBER 31, 2022
(CORPORATE)

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SCHEDULE J-3
PAGE 2 OF 2
WITNESS RESPONSIBLE:
C. BAUER

LINE NO.	DEBT ISSUE TYPE, COUPON RATE			DATE ISSUED (DAY/MO/YR) (A)	MATURITY DATE (DAY/MO/YR) (B)	PRINCIPAL AMOUNT (C)	FACE AMOUNT OUTSTANDING (D)	UNAMORT. (DISCOUNT) OR PREMIUM (E)	UNAMORT. DEBT EXPENSE (F)	UNAMORT. LOSS ON REACQUIRED DEBT (G)	CARRYING VALUE (H=D+E-F-G)	ANNUAL INTEREST COST(*) (I)
						($)	($)	($)	($)	($)	($)	($)
1	Unamortized Loss on Reacquired Debt											
2												
3	7.65% due 7/15/2025									194,299	(194,299)	63,938
4	5.5% due 1/1/2024									57,980	(57,980)	38,654
5	6.5% due 1/15/2022									-	-	2,102
6	Variable rate PCB, due 8/1/2027									82,634	(82,634)	15,569
7												
8	Other Long Term Debt											
9	LT Commercial Paper	0.541%	Series		16-Mar-26	25,000,000	25,000,000	-	-	-	25,000,000	135,133
10	Debentures	3.860%	Series	26-Jul-06	01-Aug-27	26,720,000	26,720,000	-	101,255	-	26,618,745	1,051,311
11	Debentures	Variable	Series	03-Dec-08	01-Aug-27	50,000,000	50,000,000	-	127,000	-	49,873,000	681,713
12	Debentures	6.200%	Series	10-Mar-06	10-Mar-36	65,000,000	65,000,000	(167,905)	298,278	-	64,533,817	4,064,049
13	Debentures	3.420%	Series	05-Jan-16	15-Jan-26	45,000,000	45,000,000	-	84,265	-	44,915,735	1,562,811
14	Debentures	4.450%	Series	05-Jan-16	15-Jan-46	50,000,000	50,000,000	-	208,694	-	49,791,306	2,233,866
15	Debentures	3.350%	Series	07-Sep-17	15-Sep-29	30,000,000	30,000,000	-	74,605	-	29,925,396	1,015,354
16	Debentures	4.110%	Series	07-Sep-17	15-Sep-47	30,000,000	30,000,000	-	104,505	-	29,895,495	1,237,146
17	Debentures	4.260%	Series	07-Sep-17	15-Sep-57	30,000,000	30,000,000	-	109,494	-	29,890,506	1,281,110
18	Debentures	4.010%	Series	03-Oct-18	15-Oct-23	25,000,000	25,000,000	-	28,558	-	24,971,442	1,024,657
19	Debentures	4.180%	Series	03-Oct-18	15-Oct-28	40,000,000	40,000,000	-	98,108	-	39,901,892	1,687,600
20	Debentures	4.620%	Series	12-Dec-18	15-Dec-48	35,000,000	35,000,000	-	124,767	-	34,875,233	1,621,716
21	Debentures	4.320%	Series	17-Jul-19	15-Jul-49	40,000,000	40,000,000	-	176,990	-	39,823,010	1,734,546
22	Debentures	3.230%	Series	26-Sep-19	01-Oct-25	95,000,000	95,000,000	-	224,317	-	94,775,683	3,137,521
23	Debentures	3.560%	Series	26-Sep-19	01-Oct-29	75,000,000	75,000,000	-	242,598	-	74,757,402	2,703,462
24	Debentures	2.650%	Series	15-Sep-20	15-Sep-30	35,000,000	35,000,000	-	104,443	-	34,895,557	940,228
25	Debentures	3.660%	Series	15-Sep-20	15-Sep-50	35,000,000	35,000,000	-	119,670	-	34,880,330	1,285,243
26	Future Debentures	3.686%	Series	15-Sep-21	15-Mar-42	50,000,000	50,000,000	-	144,817	-	49,855,183	1,850,351
27	Future Debentures	3.896%	Series	15-Sep-22	15-Mar-43	70,000,000	21,538,462	-	48,166	-	21,490,296	841,473
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30	LOC Fees				14-Feb-23	-	-	-	7,067	-	(7,067)	11,409
31	Other fees ($26.720M - remarketing, insurance, Bilateral LC)											449,011
32												
33	Current Maturities											
34	Debentures	4.010%	Series	03-Oct-18	15-Oct-23		(5,769,231)		(4,460)		(5,764,771)	(236,459)
35												
36	Totals					851,720,000	797,489,231	(167,905)	2,665,901	334,914	794,320,511	30,523,149
37												
38												
39	Embedded Cost of Long-Term Debt (I / H)											3.843%

(*) Annualized interest cost plus (or minus) amortization of discount or premium plus amortization of issue costs minus (or plus) amortization of gain (or loss) on reacquired debt.

Long-Term Debt

Balances		FORECAST													AVERAGE
Category	issue	12/31/21	1/31/22	2/28/22	3/31/22	4/30/22	5/31/22	6/30/22	7/31/22	8/31/22	9/30/22	10/31/22	11/30/22	12/31/22	12/31/21 - 12/31/22
LT CP	LTD CP	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000
Long Term Debt	Pollution Control Bonds - 27M	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000	26,720,000
	Pollution Control Bonds - 50M	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
	Unsecured - due 2036	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000	65,000,000
	Unsecured - Private - due 2026	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000	45,000,000
	Unsecured - private - due 2046	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
	Unsecured - Private due 2029	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
	Unsecured - Private due 2047	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
	Unsecured - Private due 2057	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
	Unsecured - Private due 2023	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000
	Unsecured - Private due 2028	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000
	Unsecured - Private due 2048	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000
	Unsecured - Private due 2025	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000	95,000,000
	Unsecured - Private due 2029	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000
	Unsecured - Private due 2030	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000
	Unsecured - Private due 2050	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000
	Unsecured - Private due 2049	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000
Future Long term debt	Forecasted bond offerings	-	-	-	-	-	-	-	-	-	70,000,000	70,000,000	70,000,000	70,000,000	21,538,462
	Forecasted bond offerings	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Projected Balances of Unamortized Loss on Reacquired Debt	7.65 due July 2025	(226,268)	(220,940)	(215,612)	(210,284)	(204,956)	(199,627)	(194,299)	(188,971)	(183,643)	(178,315)	(172,987)	(167,659)	(162,330)	(194,299)
	5.5 due January 2024	(77,307)	(74,086)	(70,865)	(67,644)	(64,423)	(61,202)	(57,980)	(54,759)	(51,538)	(48,317)	(45,096)	(41,875)	(38,654)	(57,980)
	6.5 due November 2022	(3,980)	(3,600)	(3,219)	(2,839)	(2,459)	(2,079)	(1,698)	(1,318)	(938)	(558)	(177)	-	-	(1,759)
	VAR due August 2027	(86,926)	(85,628)	(84,331)	(83,033)	(81,736)	(80,439)	(79,141)	(77,844)	(85,628)	(84,331)	(83,033)	(81,736)	(80,439)	(82,634)
Projected Balances of Unamortized Debt Issuance Expenses	Pollution Control Bonds - 27M	(111,215)	(109,555)	(107,895)	(106,235)	(104,575)	(102,915)	(101,255)	(99,595)	(97,935)	(96,276)	(94,616)	(92,956)	(91,296)	(101,255)
	Pollution Control Bonds - 50M	(139,290)	(137,242)	(135,193)	(133,145)	(131,096)	(129,048)	(127,000)	(124,951)	(122,903)	(120,854)	(118,806)	(116,758)	(114,709)	(127,000)
	Unsecured - due 2036	(309,171)	(307,355)	(305,540)	(303,724)	(301,909)	(300,093)	(298,278)	(296,463)	(294,647)	(292,832)	(291,016)	(289,201)	(287,385)	(298,278)
	Unsecured - Private - due 2026	(96,170)	(94,186)	(92,202)	(90,217)	(88,233)	(86,249)	(84,265)	(82,280)	(80,296)	(78,312)	(76,328)	(74,343)	(72,359)	(84,265)
	Unsecured - private - due 2046	(213,127)	(212,388)	(211,649)	(210,910)	(210,171)	(209,433)	(208,694)	(207,955)	(207,216)	(206,477)	(205,738)	(205,000)	(204,261)	(208,694)
	Unsecured - Private due 2029	(79,781)	(78,919)	(78,056)	(77,193)	(76,330)	(75,467)	(74,605)	(73,742)	(72,879)	(72,016)	(71,153)	(70,290)	(69,428)	(74,605)
	Unsecured - Private due 2047	(106,578)	(106,232)	(105,887)	(105,541)	(105,196)	(104,850)	(104,505)	(104,159)	(103,814)	(103,468)	(103,123)	(102,777)	(102,432)	(104,505)
	Unsecured - Private due 2057	(111,050)	(110,790)	(110,531)	(110,272)	(110,013)	(109,754)	(109,494)	(109,235)	(108,976)	(108,717)	(108,458)	(108,199)	(107,939)	(109,494)
	Unsecured - Private due 2023	(39,636)	(37,789)	(35,943)	(34,097)	(32,250)	(30,404)	(28,558)	(26,711)	(24,865)	(23,018)	(21,172)	(19,326)	(17,479)	(28,558)
	Unsecured - Private due 2028	(105,908)	(104,608)	(103,308)	(102,008)	(100,708)	(99,408)	(98,108)	(96,808)	(95,508)	(94,208)	(92,908)	(91,608)	(90,308)	(98,108)
	Unsecured - Private due 2048	(127,125)	(126,732)	(126,339)	(125,946)	(125,553)	(125,160)	(124,767)	(124,374)	(123,981)	(123,588)	(123,195)	(122,802)	(122,409)	(124,767)
	Unsecured - Private due 2025	(258,827)	(253,075)	(247,324)	(241,572)	(235,820)	(230,069)	(224,317)	(218,565)	(212,813)	(207,062)	(201,310)	(195,558)	(189,807)	(224,317)
	Unsecured - Private due 2029	(259,328)	(256,540)	(253,752)	(250,963)	(248,175)	(245,386)	(242,598)	(239,809)	(237,021)	(234,232)	(231,444)	(228,655)	(225,867)	(242,598)
	Unsecured - Private due 2049	(180,263)	(179,718)	(179,172)	(178,627)	(178,081)	(177,536)	(176,990)	(176,445)	(175,899)	(175,354)	(174,808)	(174,263)	(173,717)	(176,990)
	Unsecured - Private due 2030	(110,807)	(109,746)	(108,686)	(107,625)	(106,564)	(105,503)	(104,443)	(103,382)	(102,321)	(101,261)	(100,200)	(99,139)	(98,079)	(104,443)
	Unsecured - Private due 2050	(121,791)	(121,437)	(121,084)	(120,730)	(120,377)	(120,023)	(119,670)	(119,316)	(118,963)	(118,609)	(118,255)	(117,902)	(117,548)	(119,670)
	Forecasted bond offerings	-	-	-	-	-	-	-	-	-	-	(209,573)	(208,720)	(207,866)	(48,166)
	Forecasted bond offerings	(148,476)	(147,866)	(147,256)	(146,646)	(146,037)	(145,427)	(144,817)	(144,207)	(143,598)	(142,988)	(142,378)	(141,768)	(141,159)	(144,817)
	MCF Fees	(287,584)	(280,114)	(272,645)	(265,175)	(257,705)	(250,236)	(242,766)	(235,296)	(227,826)	(220,357)	(212,887)	(205,417)	(197,947)	(242,766)
	LOC Fees	(12,772)	(11,821)	(10,870)	(9,920)	(8,969)	(8,018)	(7,067)	(6,117)	(5,166)	(4,215)	(3,264)	(2,314)	(1,363)	(7,067)
Projected Balances of Unamortized Debt Discount/Premium	Unsecured - due 2036	(174,037)	(173,015)	(171,993)	(170,971)	(169,949)	(168,927)	(167,905)	(166,883)	(165,861)	(164,839)	(163,817)	(162,796)	(161,774)	(167,905)
Current Maturities of LTD	Pollution Control Bonds - 50M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Unsecured - Private due 2023	-	-	-	-	-	-	-	-	-	-	(25,000,000)	(25,000,000)	(25,000,000)	(5,769,231)
Current maturities of Unamortized Loss on Reaquired Debt	6.5 due November 2022	3,980	3,600	3,219	2,839	2,459	2,079	1,698	1,318	938	558	177	-	-	1,759
Current maturities of Unamortized debt expense	Pollution Control Bonds - 50M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Unsecured - Private due 2023	-	-	-	-	-	-	-	-	-	-	21,172	19,326	17,479	4,460
Projected Carrying Value		778,336,564	778,380,217	778,423,869	778,467,522	778,511,174	778,554,827	778,598,479	778,642,132	778,676,702	848,720,355	823,554,434	823,598,940	823,643,447	794,320,511
Interest															
LT CP	LTD CP	125,331	125,331	120,894	116,160	116,160	121,663	127,165	127,165	137,005	159,965	159,965	159,965	159,965	135,133
Long term Debt	Pollution Control Bonds - 27M	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392	1,031,392
	Pollution Control Bonds - 50M	481,713	481,713	475,501	468,874	468,874	476,578	484,281	484,281	498,057	530,201	530,201	530,201	530,201	495,436
	Unsecured - due 2036	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000	4,030,000
	Unsecured - Private - due 2026	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000	1,539,000
	Unsecured - private - due 2046	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000	2,225,000
	Unsecured - Private due 2029	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000	1,005,000
	Unsecured - Private due 2047	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000	1,233,000
	Unsecured - Private due 2057	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000	1,278,000
	Unsecured - Private due 2023	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500	1,002,500
	Unsecured - Private due 2028	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000	1,672,000
	Unsecured - Private due 2048	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000	1,617,000
	Unsecured - Private due 2025	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500	3,068,500
	Unsecured - Private due 2029	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000	2,670,000
	Unsecured - Private due 2049	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000	1,728,000
	Unsecured - Private due 2030	927,500	927,500	927,500	927,500	927,500	927,500	927,500	927,500	927,500	927,500	927,500	927,500	927,500	927,500
	Unsecured - Private due 2050	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000	1,281,000
Future Long term debt	Forecasted bond offerings	-	-	-	-	-	-	-	-	-	2,727,105	2,727,105	2,727,105	2,727,105	839,109
	Forecasted bond offerings	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034	1,843,034
Projected Annualized Amortization of Loss on Reacquired Debt	7.65 due July 2025	63,938	63,938	63,938	63,938	63,938	63,938	63,938	63,938	63,938	63,938	63,938	63,938	63,938	63,938
	5.5 due January 2024	38,654	38,654	38,654	38,654	38,654	38,654	38,654	38,654	38,654	38,654	38,654	38,654	38,654	38,654
	6.5 due November 2022	4,563	4,563	4,563	4,563	4,563	4,563	4,563	4,563	4,563	4,563	4,563	-	-	3,861
	VAR due August 2027	15,569	15,569	15,569	15,569	15,569	15,569	15,569	15,569	15,569	15,569	15,569	15,569	15,569	15,569
	Pollution Control Bonds - 27M	19,919	19,919	19,919	19,919	19,919	19,919	19,919	19,919	19,919	19,919	19,919	19,919	19,919	19,919
	Pollution Control Bonds - 50M	186,277	186,277	186,277	186,277	186,277	186,277	186,277	186,277	186,277	186,277	186,277	186,277	186,277	186,277
	Unsecured - due 2036	21,785	21,785	21,785	21,785	21,785	21,785	21,785	21,785	21,785	21,785	21,785	21,785	21,785	21,785
	Unsecured - Private - due 2026	23,811	23,811	23,811	23,811	23,811	23,811	23,811	23,811	23,811	23,811	23,811	23,811	23,811	23,811
	Unsecured - private - due 2046	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866
	Unsecured - Private - due 2029	10,354	10,354	10,354	10,354	10,354	10,354	10,354	10,354	10,354	10,354	10,354	10,354	10,354	10,354
	Unsecured - private - due 2047	4,146	4,146	4,146	4,146	4,146	4,146	4,146	4,146	4,146	4,146	4,146	4,146	4,146	4,146
	Unsecured - private - due 2057	3,110	3,110	3,110	3,110	3,110	3,110	3,110	3,110	3,110	3,110	3,110	3,110	3,110	3,110

Long-Term Debt

Balances		FORECAST													AVERAGE
Category	Issue	12/31/21	1/31/22	2/28/22	3/31/22	4/30/22	5/31/22	6/30/22	7/31/22	8/31/22	9/30/22	10/31/22	11/30/22	12/31/22	12/31/21 - 12/31/22
Projected Annualized Amortization of Debt Issuance Expenses	Unsecured - Private due 2023	22,157	22,157	22,157	22,157	22,157	22,157	22,157	22,157	22,157	22,157	22,157	22,157	22,157	22,157
	Unsecured - Private due 2028	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600	15,600
	Unsecured - Private due 2048	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716
	Unsecured - Private due 2025	69,021	69,021	69,021	69,021	69,021	69,021	69,021	69,021	69,021	69,021	69,021	69,021	69,021	69,021
	Unsecured - Private due 2029	33,462	33,462	33,462	33,462	33,462	33,462	33,462	33,462	33,462	33,462	33,462	33,462	33,462	33,462
	Unsecured - Private due 2049	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546
	Unsecured - Private due 2030	12,728	12,728	12,728	12,728	12,728	12,728	12,728	12,728	12,728	12,728	12,728	12,728	12,728	12,728
	Unsecured - Private due 2050	4,243	4,243	4,243	4,243	4,243	4,243	4,243	4,243	4,243	4,243	4,243	4,243	4,243	4,243
	Future Debenture	-	-	-	-	-	-	-	-	-	-	10,244	10,244	10,244	2,364
	Future Debenture	7,317	7,317	7,317	7,317	7,317	7,317	7,317	7,317	7,317	7,317	7,317	7,317	7,317	7,317
	MCF Fees	89,637	89,637	89,637	89,637	89,637	89,637	89,637	89,637	89,637	89,637	89,637	89,637	89,637	89,637
	LOC Fees	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409
$26.7M PCB - Remarketing, Insurance, BiLat LC Facility Fees; Quarterly MCF Facility Fees	Other fees	449,011	449,011	449,011	449,011	449,011	449,011	449,011	449,011	449,011	449,011	449,011	449,011	449,011	449,011
Projected Annualized Amortization of Debt Discount	Unsecured - due 2036	12,263	12,263	12,263	12,263	12,263	12,263	12,263	12,263	12,263	12,263	12,263	12,263	12,263	12,263
Current Maturities of LTD - int. expense	Pollution Control Bonds - 50M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Unsecured - Private due 2023	-	-	-	-	-	-	-	-	-	-	(1,002,500)	(1,002,500)	(1,002,500)	(231,346)
Current maturities of Unamortized Loss on Reaquired Debt	6.5 due November 2022	(3,980)	(3,600)	(3,219)	(2,839)	(2,459)	(2,079)	(1,698)	(1,318)	(938)	(558)	(177)	-	-	(1,759)
Current maturities of Unamortized debt expense	Pollution Control Bonds - 50M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Unsecured - Private due 2023	-	-	-	-	-	-	-	-	-	-	(22,157)	(22,157)	(22,157)	(5,113)
Projected Annualized Interest Expense		**29,893,091**	**29,893,471**	**29,883,201**	**29,872,222**	**29,872,602**	**29,886,188**	**29,899,773**	**29,900,154**	**29,924,150**	**32,706,739**	**31,692,707**	**31,688,321**	**31,688,321**	**30,523,149**
Embedded Cost of Long-Term Debt		**3.841%**	**3.840%**	**3.839%**	**3.837%**	**3.837%**	**3.839%**	**3.840%**	**3.840%**	**3.843%**	**3.854%**	**3.848%**	**3.848%**	**3.847%**	**3.843%**

AG-DR-02-022

REQUEST:

Refer to the Sch_J1 – Base and Sch_J1 - Forecast tabs in STAFF-DR-01-054_Attachment_-_KPSC_GAS_SFRs-2021, and refer also to the response to Staff 1-20.

a. Provide a copy of all correspondence, analyses, and/or studies that address the Company's decision to maintain lower common equity ratios in 2019 (46.5%), 2020 (47.1%), and the base period (46.81%) compared to the test year (50.70%).

b. Explain why it was acceptable to the Company and the rating agencies to maintain these lower common equity ratios in 2019, 2020, and the base period.

c. Provide a copy of all correspondence, analyses, and/or studies that address the decision/need to increase the common equity ratio from the 2019, 2020, and base period levels to the test year.

d. Provide a copy of all correspondence, analyses, and/or studies that address the decision to increase the common equity ratio to 50.70% in the test year as opposed to a lower level or a higher level.

e. Provide all documentation for the assumed common equity ratio of 50.70% in the test year.

RESPONSE:

a. Prior to 2019 Duke Energy Kentucky's historical common equity ratios were more balanced and consistent compared to the 2019 and 2020 levels. Beginning in 2019 the Company experienced a two year period of elevated capital investments on various projects including but not limited to coal ash handling and remediation, advanced metering infrastructure and electric distribution projects to enhance system reliability.

The impact of the elevated capital investments increased the amount of debt capital the Company issued over this two-year period by $280 million, which lowered the equity percentage of the capital structure in the short term. In order to rebalance the capital structure, the Company suspended utility dividends up to the parent company, Duke Energy Ohio, and pursued three consecutive rate cases (both natural gas and electric) beginning in 2018 to include recovery of these capital investments in its cost of service. It is important to note that the Company works to maintain a balanced capital structure over the long-run, not at specific points in time.

b. The Company and the rating agencies both take long-term views on the amount of leverage within the capital structure. Moody's Investor Services, stated in their January 8, 2021 credit opinion, that Duke Energy Kentucky's heightened capital program has contributed to an increased debt burden for the utility, however, the agency expects annual investments to moderate further which should relieve some pressure on credit metrics. The increased cadence in rate cases to include these investments in the Company's cost of service, combined with the generally supportive regulatory environment in Kentucky remain key to the rating agencies' comfort in assessing the utility's credit quality over the long run.

c. The Company manages to a balanced capital structure over the long-run. When the company issued long-term debt of $210 million in 2019, $70 million in 2020, and expects to issue $50 million in 2021, the debt component of the capital structure increased in the near term. It takes time to work back to a more balanced capital structure. This occurs as the Company seeks recovery of the investments that gave rise to the increased debt levels, through retained earnings, and if necessary, through equity contributions from the utility's parent, Duke Energy Ohio. All of these actions are being taken which leads to a balanced capital structure in the test year.

d. Please see response to (c) above.

e. Please see AG-DR-02-022(e) Attachment.

PERSON RESPONSIBLE: Chris R. Bauer

$000s

	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Average
Common Equity	991,671	999,466	1,007,927	1,032,910	1,034,532	1,036,823	1,039,503	1,043,452	1,048,068	1,050,337	1,052,774	1,057,943	1,061,452	
Less: Goodwill	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	(173,032)	
Less: Purch Acctg	(249)	(249)	(249)	(249)	(249)	(249)	(249)	(249)	(249)	(249)	(249)	(249)	(249)	
	818,390	826,185	834,645	859,628	861,251	863,541	866,221	870,170	874,787	877,055	879,493	884,661	888,171	861,861

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-023

REQUEST:

Refer to the Company's response to AG 1-48.

a. Identify the source of the assumption to maintain a "consistent level of total debt" from the base year to the test year. Also, provide a copy of all documentation of this assumption, including the specific decisionmakers who approved the assumption (entity, positions, and names).

b. Identify and describe all reasons why the Company would or should maintain a "consistent level of total debt" over this time period. Provide a copy of all documentation relied on for your response.

RESPONSE:

a. The phrase "consistent level of total debt" was used in AG 1-48 when comparing the long-term plus short-term debt ("total debt") on the base period Schedule J-1 to the forecasted period Schedule J-1. The amount of total debt in the base versus forecast periods changes by only $16 million while the common equity balance is expected to increase by approximately $110 million.

b. In the period from August 31, 2021 (the base period) to December 31, 2022 (the forecasted period), the two long-term debt issuances are used, in combination with internally generated funds, to term out short-term borrowings from the utility money pool and to refinance existing maturities. The overall level of total debt in this timeframe remains fairly consistent, only rising by $16 million. This is just a function of timing of external debt financing needs, not an objective or target.

PERSON RESPONSIBLE: Chris R. Bauer

AG-DR-02-024

REQUEST:

Refer to the Company's response to AG 1-49.

a. Provide the Company's target credit ratings and the specific target credit metrics to achieve those target credit ratings in each year 2019, 2020, 2021, the base year, and the test year. Provide all documentation that the target credit metrics provided in this response were its actual targets in the historic years and are its target credit metrics for the base year and the test year.

b. Provide the Company's "approved capital structure" as referenced in the response to each year 2019, 2020, 2021, the base year, and the test year. Provide a copy of all documentation that demonstrates the capital structures provided in this response actually were "approved" and indicates by whom (entity, positions, and names) they were "approved."

RESPONSE:

a. Consistent with the credit rating agencies expectations, the Company's goal is to maintain strong investment grade credit ratings and therefore, aims to generate sufficient cash flows to maintain FFO to Debt in the high teens over the long run. The actual credit metrics from historical years 2019 and 2020 can be found on page two of the previously provided 2021 Moody's Credit Opinion Report (AG-DR-01-057 Attachment 2).

b. The Company targets a balanced capital structure over the long run. Please see AG-DR-02-022 for additional discussion on the long-term management of the Company's capital structure.

PERSON RESPONSIBLE: Chris R. Bauer

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-025

REQUEST:

Refer to the Company's response to AG 1-68.

a. Provide the calculation of the DEBS total Company "rate base by components and in total and the DEK allocation of each "rate base component" times the DEK grossed-up rate of return in an Excel spreadsheet in live format with all formulas intact.

b. Provide the DEBS total Company interest expense incurred in 2018, 2019, 2020, the base year, and the test year.

c. Provide the DEBS trial balances for 2019 at December 31, 2019 and for 2020 at December 31, 2020.

RESPONSE:

a. Please see previously provided AG-DR-01-068 Attachments.

b. Please see AG-DR-02-025(b) Attachment.

c. Please see AG-DR-02-025(c) Attachments 1 and 2.

PERSON RESPONSIBLE: Jeffrey R. Setser

Business Unit CB	20013

YTD Actual Amount	Column Labels				
Row Labels	**2018**	**2019**	**2020**	**2021**	**Grand Total**
0430216 - IC Moneypool - Interest Exp	9,826,265.24	10,702,308.78	4,121,442.87	629,548.17	25,279,565.06
0431000 - Int Exp-Taxes	9,201.97	1,126.00	(159,417.26)	1.75	(149,087.54)
0431002 - Int Exp-Other	10,423,912.68	6,081,705.70			16,505,618.38
0431130 - Interest Exp - Capital Lease		4,380,453.01	10,506,153.25	3,498,885.62	18,385,491.88
Grand Total	**20,259,379.89**	**21,165,593.49**	**14,468,178.86**	**4,128,435.54**	**60,021,587.78**

Duke Energy Business Services

Working Trial Balance
December 2019
Year-to-Date

	December 2019 Actuals	December 2018 Actuals	Variance
0131100 - Cash - Various Banks	21,137,700	11,612,913	9,524,787
0131710 - Cash - FUNB Payroll Apd	1,628,111	181,002	1,447,109
0131711 - Cash - BoA Payroll Checks (I)	(11,303)	(11,658)	355
0131714 - Cash - DEBS General	(10,489,700)	(12,850,469)	2,360,769
0131780 - Peoplesoft Payables	(10,400,682)	(11,323,866)	923,184
0131141 - Cash PNC 3752	(89,819)	(128,764)	38,944
0131235 - Cash Wells 7780 PE-SVC Co	6,580	10,652	(4,071)
0131034 - Cash BOA 0484 DEBS	(146,195)	(148,625)	2,430
1111_CASH - Third Party Cash	1,634,691	(12,658,816)	14,293,507
Cash and Cash Equivalents	1,634,691	(12,658,816)	14,293,507
0142010 - Accounts Receivable	-	-	-
0142011 - Accounts Receivable Other	-	-	-
0143011 - A/R - Other - Gen Acctg	10,414,042	8,938,607	1,475,435
0143012 - A/R - Employee Misc (I)	-	-	-
0143068 - Parking Funding Receivable	-	-	-
0143110 - Misc A/R - Clearing	2,152,275	2,300,000	(147,725)
0143130 - Misc A/R - Stores	-	-	-
0143150 - Emp Receivable Stock Option Tax	0	-	0
0143180 - Ret Med Life Den/Prem Withheld	(28,479)	(16,904)	(11,575)
0143320 - Mar Billed - Edp	(5,574)	(54,167)	48,594
0142801 - A/R-Passport Interface	0	-	0
0142830 - A/R-Merch/Jobb/Contract Work	6,926	6,926	-
0143271 - Misc Accts Rec Fuel	-	-	-
0143155 - Other A/R - Miscelleneous	5,854,069	44,082	5,809,987
0184023 - Clearing Payroll Fixed Distr	22,732	13,778	8,954
0142802 - A/R - Gas	-	-	-
1210_ACCT_REC_TRADE - A/R - Trade	18,415,991	11,232,322	7,183,669
0144700 - Prov for MARBS Uncollectibles	(500)	(500)	-
1215_ACCT_REC_AFDA - Allowance For Doubtful Accounts A/R	(500)	(500)	-
0143927 - Employee Receivables	(25,704)	13,265	(38,969)
0146777 - AR Intercompany Crossbill (I)	-	-	-
0146999 - Inter - Unit Unconsolidated BU	1,325,181	289,197	1,035,983
0143119 - Off - System Storms Receivables	8,747	2,033	6,714
1231_ACCT_REC_OTHER - A/R - Other	1,308,224	304,495	1,003,729
Receivables	19,723,715	11,536,317	8,187,398
0146000 - AR Intercompany Crossbill	65,308,538	77,666,619	(12,358,082)
0146974 - A/R - Affiliates	550,464	679,629	(129,165)
0146009 - I/C AR Rollup	583,758,665	503,171,242	80,587,424
1233_ACCT_REC_CONS - Intercompany Accounts Receivable	649,617,667	581,517,490	68,100,177
Receivables from affiliated companies	649,617,667	581,517,490	68,100,177
0151126- Fuel Stock - Propane	-	-	-
1311_OIL_GAS_FUEL - Oil Gas and Other Fuel	-	-	-
0151150 - Jet Fuel	104,023	96,157	7,866
0154100 - Inventory	24,506,050	24,234,984	271,066
0163110 - Stores Expense	176,314	-	176,314
0163180 - Freight and Express	-	-	-
1321_OTHER_MATERIAL - Other Materials	24,786,387	24,331,141	455,246
Inventory	24,786,387	24,331,141	455,246

Duke Energy Business Services

Working Trial Balance
December 2019
Year-to-Date

	December 2019 Actuals	December 2018 Actuals	Variance
0182340 - Sch M: Vac Accrual Reg Asset	64,346,918	65,729,802	(1,382,884)
1491_REG_ASSET_OCA - Other Current Assets-Reg	64,346,918	65,729,802	(1,382,884)
Regulatory Assets	64,346,918	65,729,802	(1,382,884)
0165011 - Ppd - Software - Purchase	67,975,568	62,300,876	5,674,691
0165100 - Unexpired Insurance	1	1	0
0165400 - Misc Prepaid Expenses	1,391,918	938,825	453,093
0165513 - Prepaid Expense - Misc.	(457,777)	389,084	(846,862)
0165514 - Prepaid Rent/Deposit	3,074,821	3,074,821	-
1410_1470_PPAY_OTHER - Other Pre - Paid Assets	71,984,530	66,703,607	5,280,923
0165000 - Other Current Assets	-	-	-
0172004 - Rents Rec-Real Estate	87,406	18,336	69,071
0186039 - East Bend CO2 Capture System	6,473	6,227	246
1490_OTH_CUR_ASSETS - Other Current Assets	93,879	24,563	69,316
0165075 - Interco Prepaid Insu SchM	0	0	-
1498_CON_OT_CT_ASSET - Intercompany Other Current Assets	0	0	-
Other	72,078,409	66,728,170	5,350,239
Total Current Assets	*832,187,788*	*737,184,105*	*95,003,683*
0107000 - SCHM Cwip	123,990,703	284,147,189	(160,156,485)
0107004 - SCHM CWIP (SOFTWARE)	132,418,792	20,323,828	112,094,964
0121500 - NonUtility - Construction Wip	-	-	-
1717_PPE_CIP - Construction in Progress	256,409,496	304,471,017	(48,061,521)
0101000 - Property Plant and Equipment	1,891,508,223	1,803,552,388	87,955,835
0108552 - Non-Reg Plant in Svc Res Adj	(44,887,436)	(44,887,436)	-
0105030 - Elect Plnt Held for Future Use	-	-	-
0118200 - Other Utility Plant	-	-	-
0101103 - Cap Lease Rate Base	81,476,969	-	81,476,969
1718_PPE_OTHER - Other	1,928,097,756	1,758,664,952	169,432,804
0106000 - Comp Const Unclassified	52,239,895	-	52,239,895
1719_PPE_REG_PLT_ELE - Reg Plant- Elec gen, dist and trans	52,239,895	-	52,239,895
0114007 - Pur Acctg - PpandE	-	-	-
1721_PPE_NR_PLT_OTH - Unreg Plant - Other Bldgs and Imp	-	-	-
Cost	2,236,747,146	2,063,135,969	173,611,177
0108000 - Accumulated DDandA - Ppande	-	-	-
0108150 - Rsrv For Deprec - General P (I)	-	-	-
0108600 - SCHM Retirement Wip	54,803	4,586	50,217
0108203 - Acc DD&A-Cap Rate Base	(20,341,136)	-	(20,341,136)
1734_ACC_DDA_REG - Accumulated Depr Reg	(20,286,333)	4,586	(20,290,919)
0122000 - DDandA - NonUtil Prop - Gen	(1,293,175,351)	(1,183,236,765)	(109,938,586)
1735_ACC_DDA_NR - Accumulated Depr NonReg	(1,293,175,351)	(1,183,236,765)	(109,938,586)
Less Accumulated Depreciation and Amortization	(1,313,461,684)	(1,183,232,179)	(130,229,505)
Net Property Plant and Equipment	*923,285,462*	*879,903,790*	*43,381,672*
0182359 - REPS Incremental Costs	60,384	-	60,384
0182716 - Ohio Gas Integrity Deferral Co	-	-	-
0186295 - Deferred Storm Expenses	-	-	-
0186111 - Cust Connect Def O&M	-	-	-
0186028 - 2018 DEK Gas Rate Case Def	4,001	-	4,001
0182539 - RIDGEGEN PPA BUYOUT REG ASSET	-	-	-
0182572 - SC H3659 Implementation	-	-	-
1861_ODA_REG_ASSET - Other Deferred Debits - Regulatory Asset	64,385	-	64,385

Duke Energy Business Services

Working Trial Balance
December 2019
Year-to-Date

	December 2019 Actuals	December 2018 Actuals	Variance
0182318 - Other Reg Assets - Gen Acct	454,060,041	456,171,887	(2,111,846)
0182801 - Pension Post Retire P Acctg - FAS87 NQ	39,485,627	30,700,883	8,784,744
0186802 - Accr Pen FAS158 - Qual	24,856,038	35,182,581	(10,326,543)
0186171 -Reg Asset FAS 158 OCI NQ	10,340,995	9,644,051	696,944
1870_REG_ASSET_PEN - Regulatory Asset - Pension	528,742,700	531,699,402	(2,956,701)
Regulatory Assets	528,807,086	531,699,402	(2,892,316)
0101102 - Oper Lease Right of Use Asset	310,881,352	-	310,881,352
0101110 - Oper Lse Right of Use Asset RH	44,907,465	-	44,907,465
0108202 - Accumulated DD&A - ROU Asset	(57,430,834)	-	(57,430,834)
0108210 - Depr Lse Right of use Asset RH	(2,448,141)	-	(2,448,141)
1739_OP_LEASE_A - Oper Lease Right of Use Assets	295,909,842	-	295,909,842
Operating Lease Right-of-Use assets	295,909,842	-	295,909,842
1231015 - Current Year Earnings of Sub - Loaded	-	-	-
1501_INV_CON_CO_CUR - Investment in Consolidated Companies	-	-	-
Investment in Consolidated Subsidiaries	-	-	-
0124310 - Other Assets	-	-	-
0186984 - Other Long-Term Assets	4,665,000	4,665,000	-
0184670 - Aerial Patrol Expense	2,598	19,608	(17,010)
0186029 - Misc Def Debit MISO Activity	0	0	-
0186889- Asset Recovery Deferred	964,426	820,811	143,615
0186201- Def Project/Acq Exp	-	-	-
0123220 - Duke Engineering and Servs Inc (I)	-	-	-
0186882 - Straight Line Lease Defer DR	89,268	-	89,268
1508_OTHER_ASSETS - Other Assets - Long-Term	5,721,291	5,505,419	215,872
0124400 - Cash Surrender Value - Life	8,417,950	8,255,492	162,458
1518_NCA_EXEC_INS - Non Current Assets - Executive Insurance	8,417,950	8,255,492	162,458
0124073 - Investments in Projects	-	-	-
1519_NCA_INVST - Non Current Assets - Investments	-	-	-
0128716 - Prefunded Pension (major)	(202,188,343)	(158,594,751)	(43,593,592)
0128717 -Prefunded Pension	99,772,222	69,390,343	30,381,879
1894_PRE_PENSION - Pre - Funded Pension Costs	(102,416,121)	(89,204,408)	(13,211,713)
0183000 - Prelim Survey and Investigation	785	25,938	(25,153)
0184460 - Captive Insurance Receivable	-	-	-
0186110 - Miscellaneous Work in Process	101,555	40,827	60,728
0186120 - Misc. Wip - Fp Dist. Wids	2,911	2,040	871
0186290 - Oth Deferred Charges - Operation	0	49,843,697	(49,843,697)
0186450 - Error Suspense - Other Product	(2,054,512)	(653,461)	(1,401,051)
0186460 - Error Suspense - Mapps(Invoice)	51,363	19,367	31,996
0186470 - Error Suspense - Corp Payroll	155	-	155
0186480 - Misc Debits To Be Cleared	182,252	184,682	(2,430)
0803150 - Med/Heavy Trucks Gvwr > 26K	4,151,318	3,650,931	500,386
0803290 - Miscellaneous Expense	1,559,473,688	1,366,803,075	192,670,613
0803400 - Auto and Truck Exp Distributed	(1,563,625,907)	(1,370,454,305)	(193,171,601)
0820000 - Fabricated Equipment	-	-	-
0830200 - Trenchers and Cable Plows	299	299	-
0830360 - Mobile Equipment	602	-	602
0186104 - Deferred Asset-Exit Costs	3,724,281	5,857,937	(2,133,656)
0186605 - Misc Defer Debit Workers Comp	-	-	-
0165518 - MW - Prepaid Expenses - LT	-	-	-

Duke Energy Business Services

Working Trial Balance
December 2019
Year-to-Date

	December 2019 Actuals	December 2018 Actuals	Variance
1862_OTHER_DEF_DR - Other Deferred Debits	2,008,791	55,321,027	(53,312,236)
0804110 - Unproductive Time Distributed	11,536	-	11,536
0804210 - Vacations	-	-	-
0804220 - Holidays	-	-	-
0804280 - Scheduled Time Earned Unworked	-	-	-
0804290 - Other Excused Absences	-	-	-
0804330 - Sick	-	-	-
1867_ODA_CLR_LBR - Other Deferred Debits - Labor Clearing	11,536	-	11,536
0143223 - LT Tax Reclass State Dr	857,944	3,058,696	(2,200,752)
1524_LT_TAX_RCVABLE - Long Term Tax Receivable	857,944	3,058,696	(2,200,752)
0106014 - Intangibles General	-	-	-
1522_INTANG_OTHER - Intangibles, net	-	-	-
Other	(85,398,609)	(17,063,774)	(68,334,835)
Total Other Noncurrent Assets	*739,318,318*	*514,635,628*	*224,682,691*
Balance_Account	0	0	0
Total Assets	**2,494,791,568**	**2,131,723,523**	**363,068,045**

Duke Energy Business Services

Working Trial Balance
December 2019
Year-to-Date

	December 2019 Actuals	December 2018 Actuals	Variance
0230540 - Pmpa	-	-	-
0232000 - A/P Vendors Payable	-	-	-
0232002 - A/P - Misc - Gen - Acctg	31,156,575	32,993,273	(1,836,697)
0232009 - Purchasing Card Accrual	11,484,491	15,960,724	(4,476,234)
0232016 - AP PS8.9 Vendors Payable	126,298,968	158,897,479	(32,598,511)
0232018- EAM Payables	229,405,427	255,201,063	(25,795,635)
0232110 - Vouchers Payable - Automated	13,457,468	27,293,850	(13,836,382)
0232120 - Vouchers Payable - Special	20,802,277	14,280,480	6,521,797
0232135 - Employee Expense Payable	0	0	0
0232181 - Natural Gas Payable	-	-	-
0232221 - Employee Relocation - Nei	(165,841)	(226,620)	60,779
0232897- Misc AP - Manual	-	-	-
0232996 - Capital - Accruals	22,942,473	22,544,594	397,879
0234800 - Other	-	-	-
0242110 - Contract Retentions	1,923,525	3,019,804	(1,096,279)
2102_ACCT_PAY_TRADE - Accounts Payable Trade	457,305,364	529,964,647	(72,659,283)
0232061 - Checks not presented - reclass	21,137,700	11,612,913	9,524,787
2104_AP_BANKS - Accounts Payable Banks	21,137,700	11,612,913	9,524,787
Accounts Payable	478,443,063	541,577,560	(63,134,496)
0232232 - A/P Affiliates	10,805,211	9,068,264	1,736,947
2107_AP_CONS_CO - Intercompany Accounts Payable	10,805,211	9,068,264	1,736,947
Accounts payable to affiliated companies	10,805,211	9,068,264	1,736,947
0233150 - IC Moneypool - ST Notes Pay	408,828,000	220,931,000	187,897,000
2204_NOTE_PAY_CONS - Intercompany Notes Payable	408,828,000	220,931,000	187,897,000
Notes payable to affiliated companies	408,828,000	220,931,000	187,897,000
0236981 - Fed Inc Tax Payable - Prev Yr	-	-	-
0236990 - Fed Inc Tax Payable - Current	15,343,515	29,691,067	(14,347,552)
2411_ACC_FIT - Accrued Federal Income Taxes	15,343,515	29,691,067	(14,347,552)
0236001 - State It Payable Other	2,112,024	4,342,129	(2,230,105)
0236965 - Accrued SIT - Prior Year	(138,045)	(143,121)	5,076
2412_ACC_SIT - Accrued State Income Taxes	1,973,979	4,199,008	(2,225,029)
0236470 - Franchise Tax Accrual	(9)	852,916	(852,925)
0236840 - Ohio Commercial Activity Tax	(416)	-	(416)
2421_OTHER_ACC_TAX - Other Accrued Taxes	(425)	852,916	(853,341)
0236906 - Use Tax Payable	(57,906)	(358,504)	300,597
2423_ACC_TAX_SLS_USE - Accrued Sales Tax Use	(57,906)	(358,504)	300,597
0236918 - Accr Ad Valorem Tax 2006	-	-	-
2424_ACC_TAX_PROP - Accrued Property Tax	-	-	-
0236150 - St/Local Unemployment Tax Liab	23,109	7,645	15,464
0236700 - Employer FICA Tax Liab	10,271,437	9,330,414	941,022
0236750 - Federal Unemployment Tax Liab	8,435	8,160	275
0241110 - State Income Tax Wh - Employee	245,030	1,111,176	(866,147)
0241150 - Federal Income Tax Wh - Employee	(107,620)	(1,005)	(106,615)
0241160 - FICA Withheld - Employee	(16,630)	(1,931)	(14,699)
0241335 - Local Taxes Withheld	211,175	219,393	(8,219)
2428_ACC_TAX_PAYROLL - Accrued Payroll Tax	10,634,935	10,673,853	(38,918)
Taxes Accrued	27,894,098	45,058,340	(17,164,242)

Duke Energy Business Services

Working Trial Balance
December 2019
Year-to-Date

	December 2019 Actuals	December 2018 Actuals	Variance
0237200 - Curr Interest Accrued	-	-	-
2302_ACC_INT - Interest Accrued - Third Party	-	-	-
0234000 - IC Moneypool - ST Interest Pay	21,384	17,147	4,237
2303_ACC_INT_CONS - Intercompany Interest Accrued	21,384	17,147	4,237
Interest Accrued	21,384	17,147	4,237
0243103 - Current Cap Lease Oblig - Tax	128,226	-	128,226
2156_CLTD_CAP_LEASE - Current Ltd_Cap_Lease	128,226	-	128,226
Current Maturities of Long-Term Debt	128,226	-	128,226
0232004 - Vision Deduction	(25,841)	-	(25,841)
0232005 - Long Term Disability Deduction	113,792	90,157	23,635
0232045 - Supplemental Life Deductions	291,139	314,987	(23,848)
0232048 - Supplemental AD&D Deduction	39,946	41,920	(1,974)
0232049 - Medical & HSA Deductions	135	-	135
0232052 - Medical Spending Acct Deduct	(1)	(1)	-
0232053 - Dependent Spending Acct Deduct	-	-	-
0232067 - Dental Deductions	-	-	-
0242381 - Retirement Bank Accrual	5,102,089	6,150,556	(1,048,467)
0232068 - Employee Parking Deductions	-	-	-
0232126 - Accrued Audit Fees	1,679,001	2,199,000	(519,999)
0232230 - Accrued Liabilities	-	256,734	(256,734)
2101_ACCRUED_LIABS - Accrued Liabilities	7,200,262	9,053,354	(1,853,092)
0242420- Collect For Usa Union	-	(731)	731
2348_CL_OTH_CUST - Other Current Liabilities - Cust	-	(731)	731
0242220 - Legal Employee Deductions	11,402	3,495	7,907
0242400 - Collections for United Way	324,521	360,183	(35,662)
0242440 - Cash Coll and Contrib To Trustee	(150,490)	-	(150,490)
0242450 - Collections From Payroll - Misc	8,634	11,384	(2,750)
0242460 - Prov For Incentive Ben Prog	149,941,453	116,944,519	32,996,934
0242461 - Prior Year Incentive Accrual	-	-	-
0242490 - Vacation Carryover	101,576,457	103,262,687	(1,686,230)
0242660 - Collection - Contr Stk Pur 401 - K	8,859,720	7,719,111	1,140,609
0242690 - Executive Incentive Accrual	-	-	-
0232039 - Payable 401K Incentive Match	7,689,406	6,587,738	1,101,668
0242451- COLLECTIONS-LAUNDRY/UNIFORMS	-	-	-
0242033 - Wages Payable - Accrual	7,593,813	7,258,671	335,142
2349_CL_OTH_COMP - Other Current Liabilities - Comp	275,854,916	242,147,789	33,707,127
0232260 - Deposit Account	550,464	679,629	(129,165)
0242650 - Accrued Payable - Other	90	(198,968)	199,058
0242396 - CURR&ACCR LIAB-WORKERS COMP	11,653	11,980	(327)
0242398 - CURR&ACCR LIAB MISC	16,819	147,693	(130,874)
0242175 - Curr Operating Lease Oblig	60,545,455	-	60,545,455
0242185 - ST Oper Lse Obligation Red Hat	-	-	-
2350_OTHER_CURR_LIAB - Other Current Liabities	61,124,481	640,335	60,484,146
0242215 - Payroll Severance Reserves	14,476,353	48,942,057	(34,465,704)
0242216 - Payrll ST Retention/Spcl Rsrvs	2,953,883	2,370,837	583,046
2356_SEVR_RSRV_CLIAB - Severance Reserve	17,430,236	51,312,894	(33,882,658)
0242997 - NQ Pension Current SSERP	2,654,261	2,638,288	15,973
0242998 - OPEB Current Liab - Medical	403,296	397,686	5,610
0242999 - Misc Liab - FAS 112	1,748,018	1,758,803	(10,785)

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0242897 - NQ Pension Current ECBP	6,556,900	6,675,013	(118,113)
0242898 - OPEB Current Liab - Life	240,221	221,095	19,126
2366_OCL_PENSION - Other Current Liab-Pension	11,602,696	11,690,885	(88,189)
Other	373,212,590	314,844,525	58,368,065
Total Current Liabilities	*1,299,332,572*	*1,131,496,835*	*167,835,737*
0227103 - LT Cap Lease Oblig - Tax Oper	136,365,446	139,812,218	(3,446,772)
2508_LTD_CAP_LSE - Long-Term Debt - Cap Lse	136,365,446	139,812,218	(3,446,772)
0181888 - LOC FEE IND PCB 2009A4	-	-	-
1812_UNAMORT_DEBT - Unamortized Debt Expense	-	-	-
Long-Term Debt	*136,365,446*	*139,812,218*	*(3,446,772)*
Notes payable to affiliated companies	-	-	-
0190001 - Adit: Prepaid: Federal Taxes	(185,088,500)	(126,274,520)	(58,813,980)
0190002 - Adit: Prepaid: State Taxes	(24,937,864)	(17,019,429)	(7,918,435)
0282100 - Adit: PpandE: Federal Taxes	118,186,565	61,351,130	56,835,435
0282101 - Adit: PpandE: State Taxes	16,896,275	9,244,221	7,652,054
0283020 - Valuation Allowance	(980,963)	(980,963)	-
0283100 - Adit: Other: Federal Taxes	89,802,427	88,254,445	1,547,982
0283101 - Adit: Other: State Taxes	12,229,656	11,946,321	283,335
0190051 - Accum Deferred FIT-OCI	(4,205,895)	(4,205,895)	-
0190052 - Accum Deferred SIT-OCI	(566,265)	(566,265)	-
2671_ACC_DFIT - Accumulated Deferred Income Taxes	21,335,436	21,749,045	(413,609)
Deferred Income Taxes	21,335,436	21,749,045	(413,609)
0253690 - Pension Deferred Credits	-	-	-
0254689 - Reg Liability - OPEB Medical	27,252,133	27,271,750	(19,617)
0254690 - Reg Liability - OPEB Life	124,907	1,130,346	(1,005,439)
2647_REG_LIAB_PENSION - Reg Liability - Pension	27,377,040	28,402,096	(1,025,056)
0108620 - RWIP - Reg Liab	-	-	-
2652_REMCOST_REGLIAB - Removal Costs - Reg Liab	-	-	-
Regulatory Liabilities	27,377,040	28,402,096	(1,025,056)
0227175 - LT Operating Lease Obligation	195,121,808	-	195,121,808
0227185 - LT Oper Lse Obligation Red Hat	3,087,467	-	3,087,467
2513_LTD_OP_LSE - Operating Lease Liabilities	198,209,275	-	198,209,275
Operating Lease Liabilities	198,209,275	-	198,209,275
0228314 - OPEB NonCur Liab - Life	6,435,004	5,492,526	942,478
0228315 - OPEB NonCur Liab - Medical	61,240,074	69,889,100	(8,649,026)
0228324 - Schm Dpc Pos Emp FAS 112	0	0	-
0228325 - Schm Post Emp FAS 112	11,611,389	10,755,571	855,818
0253630 - Schm Exec Cash Bal Plan	128,614,008	120,572,766	8,041,242
0228348 - Pension Liab - FAS 87(Cinergy)	0	0	-
0228403 - Deferred Serp - Active Empl	2,324,918	2,009,099	315,819
0228405 - 2000 Class Deferred Compensat	7,851,686	7,887,602	(35,916)
0228340 -Nonqualified Plans Liability	25,342,825	25,310,214	32,611
2669_ODC_PENSION - Other Deferred Cr - Pension	243,419,905	241,916,879	1,503,026
Accrued Pension and Other Post-Retirement Benefit Costs	243,419,905	241,916,879	1,503,026
0228250 - Inactive - Schm Worker'S Comp - Other	103,297	101,391	1,906
0228280 - Schm Environmental	-	-	-
2650_ODC_INJ_DMG - Other Deferred Cr - Injury/Damage Reserv	103,297	101,391	1,906
0224696 - Other Longterm Liab	228,768	228,768	-
0242803 - Deferred Rent	(1,998,470)	21,500,216	(23,498,686)

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0253035 - Misc Def Cr - Genl Acctg	219,038	235,857	(16,819)
0253070 - Reserves - Mgp Sites FERC 228	-	-	-
0253043 - OPEB - FAS106 Grantor Trust	7,615,563	5,481,343	2,134,221
0228440 - Reserve - MGP Sites FERC 228	-	(238)	238
0228480 - Acc Prov Insurance-Environ	-	-	-
0253081 - DEF CR FASB 146 EXIT COST RES	-	12,912,471	(12,912,471)
0253082 - OTH DEFER CR MISCELLANEOUS	713,639	2,929,556	(2,215,917)
2651_OTHER_DEF_CR - Other Deferred Credits	6,778,538	43,287,973	(36,509,435)
0236942 - State Inc Tax Payable - Prior Yrs LT	77	77	-
2674_LT_LIAB_UTP - LT Liabilities UTP	77	77	-
Other	6,881,912	43,389,441	(36,507,529)
Total Other Noncurrent Liabilities	*497,223,567*	*335,457,460*	*161,766,107*
Preferred Stock Redeemable	-	-	-
0201000 - Common Stock Issued	4	4	-
3111_COMMON_STOCK - Common Stock	4	4	-
Common Stock	4	4	-
0208000 - Donations From Stockholder	47,200,000	47,200,000	-
0207008 - Additional Paid In Capital	(2,437,391)	(2,437,391)	-
0211003 - Misc Paid in Capital	214,839,126	214,839,126	-
0208010 - Donat Recvd From Stkhld Tax	(669,224)	(669,224)	-
0211004 - Misc Paid In Capital Purch Acctg	(180,602,490)	(180,602,490)	-
0211005 - Misc Paid In Capital Premerger Equity	(48,887,321)	(48,887,321)	-
3211_ADD_PAID_CAP - Additional Paid in Capital	29,442,700	29,442,700	-
Additional Paid in Capital	29,442,700	29,442,700	-
0216000 - Unapprop Retained Earnings	(44,321,728)	(44,321,728)	-
0216100 - Unappr Undistr Subsid Earnings	552,854,280	516,749,657	36,104,623
0439300 - ADJUST TO R/E	(2,803,928)	-	(2,803,928)
3311_RET_EARN - Retained Earnings	511,336,480	472,427,928	38,908,552
0439004 - Cumm Effect Acct Change Tax	-	-	-
3511_CEA - Cumulative Effect of Change in Acctg	-	-	-
Current Year Net Income	36,912,973	36,104,623	808,349
Retained Earnings	548,249,453	508,532,552	39,716,901
0219020 - FAS 106 actuarial gain or loss	-	-	-
0219101 - OCI - FAS 87 actuarial gain or loss	(20,374,787)	(20,374,787)	-
0219103 - OCI - NQ 87 actuarial gain or loss	(1,707,007)	(1,707,007)	-
0219106 - OCI - FAS 106 actuarial gain or loss	1,995,221	1,995,221	-
0219035 - OCI-Actuarial GL Qual	0	0	-
0219036 - OCI-Actuarial GL Qual Fed Tx	4,161,058	6,935,095	(2,774,037)
0219037 - OCI-Actuarial GL Qual St Tx	560,227	560,227	-
0219038 - OCI-Actuarial GL NQ	(507,764)	(507,764)	-
0219039 - OCI-Actuarial GL NQ Fed Tx	452,313	753,855	(301,542)
0219040 - OCI Actuarial GL NQ St Tx	60,899	60,899	-
0219041 - FAS 106 Actuarial GL Fed Tx	(407,476)	(679,126)	271,650
0219042 - FAS 106 Actuarial GL St Tx	(54,860)	(54,860)	-
ACCUM_OCI_OPEB - Accumulated OCI - Pension and OPEB	(15,822,174)	(13,018,246)	(2,803,928)
OCI Total excluding EPU	(15,822,174)	(13,018,246)	(2,803,928)
Total Other Comprehensive Income	(15,822,174)	(13,018,246)	(2,803,928)
3411_ACCUM_OCI - Accumulated Other Comprehensive Income	(15,822,174)	(13,018,246)	(2,803,928)
Accumulated Other Comprehensive Income	(15,822,174)	(13,018,246)	(2,803,928)

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Equity	561,869,982	524,957,010	36,912,973
Total Equity Including Noncontrolling Interest	*561,869,982*	*524,957,010*	*36,912,973*
Total Liabilities and Equity	***2,494,791,568***	***2,131,723,523***	***363,068,045***

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	December 2019 Actuals	December 2018 Actuals	Variance
0440000 - Residential	-	-	-
45XX_ELECTRICITY_REG - Electric Sales Regulated	-	-	-
0456949 - Other Revenue Affiliate	56,734,639	51,511,543	5,223,096
4106_IC_ELEC_REG - Interco Electric Rev - Reg	56,734,639	51,511,543	5,223,096
0417007 - Misc Revenue-Reg	(408)	933,891	(934,300)
0454400 - Other Electric Rents	20,250	73,772	(53,522)
0456100 - Profit Or Loss on Sale of M&S	(1,075)	(22,182)	21,107
0456102 - Distribution Charge - Network	-	(25)	25
4507_OTH_ELEC_REG - Other Electric Revenue Regulated	18,767	985,456	(966,689)
Regulated Electric	56,753,406	52,497,000	4,256,406
0489200 - Transportation Fees	-	(23)	23
42XX_TRNSPRT_GAS_REG - Transport Gas Regulated	-	(23)	23
Regulated Natural Gas	-	(23)	23
0417000 - Misc Revenue	3,606,984	2,460,842	1,146,142
46XX_OTH_ELEC_REV_NR - Other Electric Rev NonRegulated	3,606,984	2,460,842	1,146,142
0457103 - SC Dir Op Rev Ofst	(66,981,864)	(63,706,426)	(3,275,438)
0457203 - SC Indr Op Rev Offst	(3,626,826)	(3,441,371)	(185,456)
0417310 - Products and Svcs - NonReg	(66,981,864)	(63,706,426)	(3,275,438)
4607_OTH_MISC_REV_NR - Other Misc Rev NonReg	(3,626,826)	(3,441,371)	(185,456)
Non-Regulated Electric, Natural Gas and Other	(19,843)	(980,529)	960,687
Total Operating Revenues	56,733,564	51,516,447	5,217,116
0591100 - Coal Purchase (I)	-	589	(589)
59XX_PURC_COAL - Purchased Coal	-	589	(589)
Cost of Natural Gas and Coal Sold	-	589	(589)
0417320 - Exp - Unreg Products and Svcs	112,094	69,766	42,327
0426400 - Exp/Civic and Political Activity	6,775,019	7,442,810	(667,791)
0426510 - Other	165	-	165
0426540 - Employee Service Club Dues	553	1,379	(826)
0457700 - Allocated Employee Bnfts Offset	4,147	-	4,147
0500000 - Suprvsn and Engrg - Steam Oper	11,811,184	14,037,617	(2,226,433)
0501150 - Coal Handling	3,575	4,901	(1,326)
0502100 - Fossil Steam Exp - Other	1,410,936	2,031,636	(620,700)
0506000 - Misc Fossil Power Expenses	3,730,393	6,528,628	(2,798,235)
0510000 - Suprvsn and Engrng - Steam Maint	2,488,514	2,849,962	(361,448)
0511000 - Maint of Structures - Steam	511,114	62	511,052
0512100 - Maint of Boiler Plant - Other	8,925	3,182	5,744
0513100 - Maint of Electric Plant - Other	639,900	652,964	(13,064)
0514000 - Maintenance - Misc Steam Plant	-	3,575	(3,575)
0524000 - Misc Expenses - Nuc Oper	-	5,264	(5,264)
0528000 - Maint Suprvsn and Enginrng - Nuc	-	570	(570)
0539000 - Misc Hydraulic Expenses	-	295	(295)
0542000 - Maint of Structures - Hydro	-	236	(236)
0543000 - Maint - Reservoir Dam and Waterway	776	-	776
0546000 - Suprvsn and Enginring - Ct Oper	-	81	(81)
0548100 - Generation Expenses - Other Ct	78	-	78

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0549000 - Misc - Power Generation Expenses	97,706	54,752	42,954
0551000 - Suprvsn and Enginring - Ct Maint	-	3,895	(3,895)
0553000 - Maint - Gentg and Elect Equip - Ct	45,077	-	45,077
0554000 - Misc Power Generation Plant - Ct	7,951	547	7,404
0557000 - Other Expenses - Oper	238	49,486	(49,247)
0561100 - Load Dispatch - Reliability	11,817	12,230	(413)
0561200 - Load Dispatch - MnitorandOprtrnsys	16,928	2,922	14,005
0561300 - Load Dispatch - TranssvcandSch	731	296	435
0566000 - Misc Trans Exp - Other	21,705	20,376	1,329
0569100 - Maint of Computer Hardware	-	235	(235)
0569200 - Maint of Computer Software	13,642	4,532	9,111
0571000 - Maint of Overhead Lines - Trans	2,320	-	2,320
0580000 - Supervsn and Engring - Dist Oper	-	27	(27)
0586000 - Meter Expenses - Dist	1,974	3,603	(1,629)
0587000 - Cust Install Exp - Other Dist	600	823	(223)
0588100 - Misc Distribution Exp - Other	10,772,381	12,493,558	(1,721,177)
0590000 - Supervsn and Engrng - Dist Maint	169	213	(44)
0593000 - Maint Overhd Lines - Other - Dist	1,879,149	340,438	1,538,711
0596000 - Maint - Streetlightng/Signl - Dist	-	8,902	(8,902)
0597000 - Maintenance of Meters - Dist	-	11,416	(11,416)
0717000 - Liq Petro Gas Exp - Vapor Proc	-	-	-
0807000 - Gas Purchased Expenses	11,589	4,539	7,050
0823000 - Storage - Gas Losses	-	-	-
0852000 - Communication System Expenses	-	250	(250)
0870000 - Distribution Sys Ops - Supv/Eng	569	121	447
0901000 - Supervision - Cust Accts	-	1,442	(1,442)
0902000 - Meter Reading Expense	24,080	303,652	(279,573)
0903000 - Cust Records and Collection Exp	74,817,270	76,113,020	(1,295,750)
0903100 - Cust Contracts and Orders - Local	4,411	17,123	(12,712)
0903200 - Cust Billing and Acct	1,941,270	2,375,444	(434,174)
0903250 - Customer Billing - Common	-	-	-
0903300 - Cust Collecting - Local	4,865	6,682	(1,817)
0903400 - Cust Receiv and Collect Exp - Edp	17,761	36,895	(19,134)
0905000 - Misc Customer Accts Expenses	-	1,603	(1,603)
0908150 - Commer/Indust Assistance Exp	-	159	(159)
0909650 - Misc Advertising Expenses	3,009	-	3,009
0910000 - Misc Cust Serv/Inform Exp	200,285	381,502	(181,217)
0910100 - Exp - Rs Reg Prod/Svces - Cstaccts	1,693,638	2,395,523	(701,885)
0911000 - Supervision	5,734	259,999	(254,265)
0912000 - Demonstrating and Selling Exp	81,181	99,731	(18,549)
0913001 - Advertising Expense	80,993	151,789	(70,797)
0916000 - Miscellaneous Sales Expense	5,211,807	5,329,359	(117,552)
0926000 - Employee Benefits	227,051,333	216,003,638	11,047,695
0926420 - Employees' Tuition Refund	40	2,281	(2,241)
0926600 - Employee Benefits - Transferred	534,232,652	581,693,987	(47,461,335)
0581004 - Load Dispatch-Dist of Elec	1,005	5,638	(4,633)
0457102 - SC Direct O&M Offst	(720,998,639)	(758,484,884)	37,486,245

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0457202 - SC Indirect O&M Ofst	(218,330,949)	(220,406,005)	2,075,056
0556000 - System Cnts & Load Dispatching	-	2,549	(2,549)
0510100 - Suprvsn and Engrng-Steam Maint - Rec	271	-	271
0553100 - CT Maint of Gen and Plant-Recoverable	-	656	(656)
0908000 - Cust Asst Exp-Conservation Programs - Rec	4,799	3,050	1,748
0912100 - Demonstration & Sell-Proj Supt - NCRC Rec	-	14,103	(14,103)
0912200 - EV Employee Incentive	15,000	-	15,000
52XX_OPER_EX - Operating Expenses	(53,556,263)	(47,044,973)	(6,511,290)
0932000 - Maintenance of General Plant	(1,838)	93	(1,930)
53XX_REPAIR_MAINT - Repairs and Maintenance	(1,838)	93	(1,930)
0924050 - Intercompany Property Insurance Exp	290,091	273,600	16,491
0931008 - A and G Rents IC	35,291,402	33,596,589	1,694,813
6X05_CON_GEN_ADMIN - Intercompany Admin and General Expenses	35,581,493	33,870,189	1,711,304
0417107 - Administrative Expenses	-	28	(28)
0426100 - Donations	3,068,250	2,045,341	1,022,909
0904001 - Bad Debt Expense	-	5,916	(5,916)
0920000 - A and G Salaries	411,136,437	454,247,874	(43,111,437)
0921100 - Employee Expenses	16,867,396	21,771,951	(4,904,554)
0921200 - Office Expenses	58,936,071	54,680,594	4,255,477
0921300 - Telephone and Telegraph Exp	80,526	17,604	62,922
0921400 - Computer Services Expenses	39,287,279	41,319,310	(2,032,032)
0921540 - Computer Rent (Go Only)	57,371,143	45,304,721	12,066,422
0921600 - Other	52,635	73,453	(20,818)
0921980 - Office Supplies and Expenses	593,957,286	396,329,193	197,628,093
0922000 - Admin Exp Transfer	78,976	83,443	(4,468)
0923000 - Outside Services Employed	145,012,734	189,988,702	(44,975,969)
0923980 - Outside Services Employee and	2,817,223	3,422,594	(605,370)
0924000 - Property Insurance	180,872	143,101	37,772
0924100 - Admin - EH&S Expense	-	297	(297)
0924980 - Property Insurance For Corp.	13,373,205	15,050,383	(1,677,178)
0925000 - Injuries and Damages	11,838	300,702	(288,865)
0925200 - Injuries and Damages - Other	563,255	710,828	(147,573)
0925980 - Injuries and Damages For Corp.	1,387,903	1,243,000	144,903
0928030 - Prof Fees Consultant	(3,364)	-	(3,364)
0928032 - Prof Fees Outside Services	-	24,275	(24,275)
0928053 - Travel Expense (I)	-	4,219	(4,219)
0930150 - Miscellaneous Advertising Exp	1,133,760	1,874,417	(740,658)
0930200 - Misc General Expenses	(174,469,729)	(162,440,023)	(12,029,707)
0930210 - Industry Association Dues	3,229,131	3,165,248	63,883
0930220 - Exp of Servicing Securities	(39,623)	26,644	(66,267)
0930230 - Dues To Various Organizations	359,951	332,075	27,876
0930240 - Director'S Expenses	5,105,863	5,126,849	(20,986)
0930250 - Buy\Sell Transf Employee Homes	1,075,567	1,470,478	(394,912)
0930600 - Leased Circuit Charges - Other	57	-	57
0930700 - Research and Development	189,290	198,290	(9,001)
0930940 - General Expenses	233,694	245,452	(11,758)
0935100 - Maint General Plant-Elec	328,097	1,120,617	(792,520)

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0935200 - Cust Infor and Computer Control	67,310	771,905	(704,595)
0107888 - CWIP - BU Bal Sht - Svc Co Exp	1,281,370,361	1,044,943,816	236,426,545
0931001 - Rents - AandG	30,613,525	29,553,339	1,060,186
0108888 - RWIP - BU Bal Sht - Svc Co Exp	8,996,668	10,486,114	(1,489,446)
0163888 - Stores Expense - BU Bal Sht - SvcCo Exp	101,345,471	101,492,648	(147,177)
0182888 - Oth Reg Assets - BU Bal Sht - SvcCo Exp	7,694,100	6,762,163	931,938
0183888 - Prelim Srvy&Invest - BU Bal Sht - SvcCo Exp	1,080,512	3,356,334	(2,275,822)
0184888 - Clearing Acct - BU Bal Sht - SvcCo Exp	(4,230,738)	(273,213)	(3,957,525)
0186888 - Misc Def Dbt - BU Bal Sht - SvcCo Exp	90,778,755	102,972,516	(12,193,761)
0121888 - Non-Util Prpty BU B/S SC Exp	7,044,540	8,325,618	(1,281,078)
0185888 - Temp Facil - BU B/S-SvcCoExp	(823,072)	(401,364)	(421,708)
0921110 - Relocation Expenses	1,334	240	1,093
0457101 - SC Direct A&G Offst	(2,033,554,913)	(1,626,930,796)	(406,624,117)
0457201 - SC Indirect A&G Ofst	(839,695,450)	(907,107,657)	67,412,207
0920100 - Salaries & Wages - Proj Supt - NCRC Rec	67,797	-	67,797
0921101 - Employee Exp - NC	2,033	4,595	(2,562)
0426300 - Penalties	2,252	879	1,373
0931003 - Lease Amortization Expense	371,600	-	371,600
6XXX_GEN_ADMIN - Administrative and General Expenses	(167,542,193)	(148,155,284)	(19,386,909)
Operations, Maintenance and Other	(185,518,801)	(161,329,975)	(24,188,826)
0403500 - Depr of General Plant	174,028,592	146,958,029	27,070,564
540X_DDA_PPE - Depreciation and Depletion	174,028,592	146,958,029	27,070,564
Depreciation and Amortization	174,028,592	146,958,029	27,070,564
0408040 - NC Property Tx - Misc NonUtility	6,625,546	7,759,759	(1,134,213)
0408120 - Franchise Tax - Non Electric	968	-	968
0408150 - State Unemployment Tax	483,214	212,647	270,568
0408151 - Federal Unemployment Tax	404,874	442,225	(37,351)
0408152 - Employer FICA Tax	62,505,897	60,207,927	2,297,970
0408153 - Employer Local Tax	4,934	-	4,934
0408470 - Franchise Tax	2,239,051	1,599,781	639,270
0408800 - Federal Highway Use Tax - Elec	51,593	49,712	1,880
0408820 - Misc NonUtility Tax	111	291	(180)
0408851 - Sales and Use Tax Exp	(424,353)	(511,688)	87,334
0408960 - Allocated Payroll Taxes	(24,801,807)	(21,721,317)	(3,080,490)
0457200 - SC Indirect PT Offst	(32,061,619)	(32,798,684)	737,066
0408205 - Highway Use Tax	59,689	69,527	(9,838)
0457104 - SC Direct PT Offst	(15,088,744)	(15,354,902)	266,158
55XX_MISC_TAX - Miscellaneous Taxes	(645)	(44,722)	44,077
Property and Other Taxes	(645)	(44,722)	44,077
Total Operating Expenses	(11,490,853)	(14,416,079)	2,925,226
0421100 - Gain on Disposal of Property	29	1,390,084	(1,390,054)
0421200 - Loss on Disposal of Property	(1,285,701)	(3,021,857)	1,736,156
0421114 - Gain/Loss on Leases	(3,278)	-	(3,278)
7519_GAINLOSS_PPE - PpandE Gain (Loss)	(1,282,393)	(1,631,774)	349,380
Gain/(Loss) on Sales of Other Assets and Other, net	(1,282,393)	(1,631,774)	349,380
Other Operating Gains and Losses	(1,282,393)	(1,631,774)	349,380
Operating Income	66,942,024	64,300,753	2,641,271

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	December 2019 Actuals	December 2018 Actuals	Variance
0421940 - Misc Income	(16,265,802)	(17,380,472)	1,114,669
0426200 - Life Insurance Expense	(162,458)	(169,843)	7,385
0457988 - Allocated other income or exp offset	(7,675,513)	26,661,664	(34,337,177)
0926999 - Non Service Cost (ASU 2017-07)	(23,778,858)	9,455,328	(33,234,186)
71XX_OTHER_INCOME - Other Income	0	(4,293)	4,293
0419240 - Miscellaneous Interest	(2,055)	(388)	(1,666)
7310_INT_DIV - Interest and Dividends	(2,055)	(388)	(1,666)
0419429 - IC Moneypool - Interest Inc	-	-	-
7330_INTERCO_INT - Intercompany Interest Income	-	-	-
Other Income and Expenses	(2,054)	(4,681)	2,627
Earnings Before Interest Expense and Taxes	66,939,969	64,296,072	2,643,897
0431400 - Int/Other Notes and Acct Pay	324,085	385,124	(61,039)
8220_INT_OTHER_DEBT - Interest on Other Debt	324,085	385,124	(61,039)
0431000 - Int Exp - Taxes	1,126	9,202	(8,076)
0431002 - Int Exp - Other	6,081,706	10,423,913	(4,342,207)
0431130 - Interest Exp - Capital Lease	4,380,453	-	4,380,453
8410_MISC_INT_EXP - Miscellaneous Interest Expense	10,463,285	10,433,115	30,170
0430216 - IC Moneypool - Interest Exp	10,702,309	9,826,265	876,044
8430_INTERCO_INT - Intercompany Interest Expense	10,702,309	9,826,265	876,044
0432000 - AFUDC Debt Component	-	-	-
0457301 - SC Ind Intrst Offset	(11,031,169)	(10,172,770)	(858,398)
8510_INT_COST_CAP - Interest Costs on Capital Debt Expense	(11,031,169)	(10,172,770)	(858,398)
Interest Expense	10,458,509	10,471,734	(13,224)
Earnings From Continuing Operations Before Income Taxes	56,481,460	53,824,338	2,657,122
0409220 - Federal Income Tax - NonUtility CY	15,343,515	29,691,067	(14,347,552)
0409221 - Federal Income Tax - NonUtility PY	1,975,437	(181,833)	2,157,269
8611_CURR_FIT - Current Federal Income Taxes	17,318,951	29,509,234	(12,190,282)
0409202 - State Income Tax NonUtility	2,112,024	4,656,863	(2,544,839)
0409233 - Tax expense - state nonutility - PY	(5,367)	305,914	(311,281)
0409297- Current State Inc Tax-Non Util	-	-	-
8612_CURR_SIT - Current State Income Taxes	2,106,657	4,962,777	(2,856,120)
0410240 - Dfit: Non - Utility: Curr Year	111,185,935	53,057,343	58,128,592
0410241 - Dfit: Non - Utility: Prior Yr Cr	1,061,898	9,500,335	(8,438,437)
0411240 - Dfit: Non - Utility: Curr Yr Cr	(109,620,586)	(66,361,458)	(43,259,128)
0411241 - Other Deferred Taxes PY	(2,501,323)	(11,079,079)	8,577,756
8621_DEF_FIT - Deferred Federal Income Taxes	125,925	(14,882,859)	15,008,783
0410242 - Dsit: Non - Utility: Curr Year	14,969,547	7,143,389	7,826,158
0410243 - Dsit: Non - Utility: Prior Year	142,969	1,279,080	(1,136,111)
0411242 - Dsit: Non - Utility: Curr Yr Cr	(14,758,796)	(8,934,592)	(5,824,204)
0411243 - Dsit: Non - Utility: Prior Yr Cr	(336,766)	(1,357,314)	1,020,548
8622_DEF_SIT - Deferred State Income Taxes	16,954	(1,869,437)	1,886,391
Income Tax Expense (Benefit) From Continuing Operations	19,568,487	17,719,715	1,848,772
Income From Continuing Operations Attributable to Duke Energy Corp	36,912,973	36,104,623	808,349
Income (Loss) From Continuing Operations	36,912,973	36,104,623	808,349
4181107 - Earnings of Sub	-	-	-
7210_EQ_SUBS - Earnings of Subsidiaries	-	-	-
Earnings (Loss) of Subsidiaries	-	-	-

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	December 2019 Actuals	December 2018 Actuals	Variance
Net Inc Bfr Ext and Chg in Acct. Prin.	36,912,973	36,104,623	808,349
Consolidated Net Income	36,912,973	36,104,623	808,349
Net Income Attributable to Company	36,912,973	36,104,623	808,349
Net Income Attributable to Controlling Interest	**36,912,973**	**36,104,623**	**808,349**

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	December 2020 Actuals	December 2019 Actuals	Variance
0131100 - Cash - Various Banks	25,460,014	21,137,700	4,322,315
0131710 - Cash - FUNB Payroll Apd	2,376,904	1,628,111	748,793
0131711 - Cash - BoA Payroll Checks (I)	-	(11,303)	11,303
0131714 - Cash - DEBS General	(6,694,232)	(10,489,700)	3,795,468
0131780 - Peoplesoft Payables	(18,063,830)	(10,400,682)	(7,663,148)
0131141 - Cash PNC 3752	(458,846)	(89,819)	(369,027)
0131235 - Cash Wells 7780 PE-SVC Co	7,871	6,580	1,290
0131034 - Cash BOA 0484 DEBS	(243,106)	(146,195)	(96,910)
1111_CASH - Third Party Cash	2,384,775	1,634,691	750,084
Cash and Cash Equivalents	2,384,775	1,634,691	750,084
0142010 - Accounts Receivable	-	-	-
0142011 - Accounts Receivable Other	-	-	-
0143011 - A/R - Other - Gen Acctg	10,692,211	10,414,042	278,169
0143068 - Parking Funding Receivable	-	-	-
0143110 - Misc A/R - Clearing	2,152,275	2,152,275	-
0143150 - Emp Receivable Stock Option Tax	0	0	-
0143180 - Ret Med Life Den/Prem Withheld	(38,849)	(28,479)	(10,369)
0143320 - Mar Billed - Edp	(20,936)	(5,574)	(15,362)
0142801 - A/R-Passport Interface	1	0	1
0142830 - A/R-Merch/Jobb/Contract Work	6,926	6,926	-
0143151 - Other A/R-Misc Non-Utility	-	-	-
0143271 - Misc Accts Rec Fuel	-	-	-
0143155 - Other A/R - Miscelleneous	91,007	5,854,069	(5,763,062)
0184023 - Clearing Payroll Fixed Distr	(13,946)	22,732	(36,678)
0142802 - A/R - Gas	-	-	-
1210_ACCT_REC_TRADE - A/R - Trade	12,868,690	18,415,991	(5,547,302)
0144700 - Prov for MARBS Uncollectibles	(500)	(500)	-
1215_ACCT_REC_AFDA - Allowance For Doubtful Accounts A/R	(500)	(500)	-
0143927 - Employee Receivables	(28,462)	(25,704)	(2,759)
0146777 - AR Intercompany Crossbill (I)	-	-	-
0146999 - Inter - Unit Unconsolidated BU	1,568,601	1,325,181	243,421
0143640 - RCBP Admin A/R	59,078	-	59,078
0143119 - Off - System Storms Receivables	12,266	8,747	3,519
1231_ACCT_REC_OTHER - A/R - Other	1,611,483	1,308,224	303,259
Receivables	14,479,672	19,723,715	(5,244,043)
0146000 - AR Intercompany Crossbill	100,356,313	65,308,538	35,047,776
0146974 - A/R - Affiliates	1,832,446	550,464	1,281,982
0146009 - I/C AR Rollup	557,044,042	583,758,665	(26,714,623)
1233_ACCT_REC_CONS - Intercompany Accounts Receivable	659,232,801	649,617,667	9,615,134
Receivables from affiliated companies	659,232,801	649,617,667	9,615,134
0151126- Fuel Stock - Propane	-	-	-
1311_OIL_GAS_FUEL - Oil Gas and Other Fuel	-	-	-
0151150 - Jet Fuel	41,078	104,023	(62,945)
0154100 - Inventory	25,845,693	24,506,050	1,339,643
0154140 - Misc Inventory	-	-	-
0163110 - Stores Expense	94	176,314	(176,220)
0163180 - Freight and Express	-	-	-
1321_OTHER_MATERIAL - Other Materials	25,886,865	24,786,387	1,100,478

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	December 2020 Actuals	December 2019 Actuals	Variance
Inventory	25,886,865	24,786,387	1,100,478
0182340 - Sch M: Vac Accrual Reg Asset	65,053,004	64,346,918	706,086
1491_REG_ASSET_OCA - Other Current Assets-Reg	65,053,004	64,346,918	706,086
Regulatory Assets	65,053,004	64,346,918	706,086
0165011 - Ppd - Software - Purchase	53,162,194	67,975,568	(14,813,373)
0165100 - Unexpired Insurance	1	1	0
0165400 - Misc Prepaid Expenses	593,435	1,391,918	(798,483)
0165513 - Prepaid Expense - Misc.	(766,971)	(457,777)	(309,194)
0165514 - Prepaid Rent/Deposit	3,074,821	3,074,821	-
1410_1470_PPAY_OTHER - Other Pre - Paid Assets	56,063,480	71,984,530	(15,921,050)
0165000 - Other Current Assets	-	-	-
0172004 - Rents Rec-Real Estate	63,507	87,406	(23,900)
0186039 - East Bend CO2 Capture System	-	6,473	(6,473)
1490_OTH_CUR_ASSETS - Other Current Assets	63,507	93,879	(30,373)
0165075 - Interco Prepaid Insu SchM	-	0	0
1498_CON_OT_CT_ASSET - Intercompany Other Current Assets	-	0	0
Other	56,126,986	72,078,409	(15,951,422)
Total Current Assets	*823,164,105*	*832,187,788*	*(9,023,683)*
0107000 - SCHM Cwip	38,985,645	123,990,703	(85,005,058)
0107004 - SCHM CWIP (SOFTWARE)	119,906,475	132,418,792	(12,512,317)
0121500 - NonUtility - Construction Wip	-	-	-
1717_PPE_CIP - Construction in Progress	158,892,120	256,409,496	(97,517,375)
0101000 - Property Plant and Equipment	2,023,015,240	1,891,508,223	131,507,018
0108552 - Non-Reg Plant in Svc Res Adj	(44,887,436)	(44,887,436)	-
0118200 - Other Utility Plant	-	-	-
0101103 - Cap Lease Rate Base	81,476,969	81,476,969	-
1718_PPE_OTHER - Other	2,059,604,773	1,928,097,756	131,507,018
0106000 - Comp Const Unclassified	106,188,629	52,239,895	53,948,734
1719_PPE_REG_PLT_ELE - Reg Plant- Elec gen, dist and trans	106,188,629	52,239,895	53,948,734
Cost	2,324,685,523	2,236,747,146	87,938,377
0108000 - Accumulated DDandA - Ppande	-	-	-
0108150 - Rsrv For Deprec - General P (I)	-	-	-
0108600 - SCHM Retirement Wip	54,803	54,803	0
0108203 - Acc DD&A-Cap Rate Base	(22,722,111)	(20,341,136)	(2,380,975)
1734_ACC_DDA_REG - Accumulated Depr Reg	(22,667,307)	(20,286,333)	(2,380,975)
0122000 - DDandA - NonUtil Prop - Gen	(1,338,969,409)	(1,293,175,351)	(45,794,058)
1735_ACC_DDA_NR - Accumulated Depr NonReg	(1,338,969,409)	(1,293,175,351)	(45,794,058)
Less Accumulated Depreciation and Amortization	(1,361,636,717)	(1,313,461,684)	(48,175,032)
Net Property Plant and Equipment	*963,048,807*	*923,285,462*	*39,763,344*
0182359 - REPS Incremental Costs	1,072	60,384	(59,312)
0186295 - Deferred Storm Expenses	-	-	-
0186111 - Cust Connect Def O&M	-	-	-
0186028 - 2018 DEK Gas Rate Case Def	-	4,001	(4,001)
0182539 - RIDGEGEN PPA BUYOUT REG ASSET	-	-	-
0186113 - DEK 2019 Rate Case - Electric	-	-	-
0182572 - SC H3659 Implementation	-	-	-
1861_ODA_REG_ASSET - Other Deferred Debits - Regulatory Asset	1,072	64,385	(63,313)
0182318 - Other Reg Assets - Gen Acct	465,681,048	454,060,041	11,621,007
0182801 - Pension Post Retire P Acctg - FAS87 NQ	44,829,273	39,485,627	5,343,646

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	December 2020 Actuals	December 2019 Actuals	Variance
0186802 - Accr Pen FAS158 - Qual	11,659,624	24,856,038	(13,196,414)
0186171 -Reg Asset FAS 158 OCI NQ	10,919,711	10,340,995	578,716
1870_REG_ASSET_PEN - Regulatory Asset - Pension	533,089,655	528,742,700	4,346,955
Regulatory Assets	533,090,728	528,807,086	4,283,642
0101102 - Oper Lease Right of Use Asset	345,364,337	310,881,352	34,482,984
0101110 - Oper Lse Right of Use Asset RH	44,907,465	44,907,465	-
0108202 - Accumulated DD&A - ROU Asset	(107,876,364)	(57,430,834)	(50,445,530)
0108210 - Depr Lse Right of use Asset RH	(5,131,085)	(2,448,141)	(2,682,944)
1739_OP_LEASE_A - Oper Lease Right of Use Assets	277,264,352	295,909,842	(18,645,489)
Operating Lease Right-of-Use assets	277,264,352	295,909,842	(18,645,489)
1231015 - Current Year Earnings of Sub - Loaded	(79)	-	(79)
1501_INV_CON_CO_CUR - Investment in Consolidated Companies	(79)	-	(79)
Investment in Consolidated Subsidiaries	(79)	-	(79)
0186984 - Other Long-Term Assets	4,665,000	4,665,000	-
0184670 - Aerial Patrol Expense	-	2,598	(2,598)
0186029 - Misc Def Debit MISO Activity	0	0	-
0186889- Asset Recovery Deferred	1,646,134	964,426	681,708
0186201- Def Project/Acq Exp	1,657,916	-	1,657,916
0186882 - Straight Line Lease Defer DR	215,063	89,268	125,795
1508_OTHER_ASSETS - Other Assets - Long-Term	8,184,113	5,721,291	2,462,822
0124400 - Cash Surrender Value - Life	8,568,993	8,417,950	151,043
1518_NCA_EXEC_INS - Non Current Assets - Executive Insurance	8,568,993	8,417,950	151,043
0128716 - Prefunded Pension (major)	0	(202,188,343)	202,188,343
0128717 -Prefunded Pension	135,629,976	99,772,222	35,857,754
1894_PRE_PENSION - Pre - Funded Pension Costs	135,629,976	(102,416,121)	238,046,097
0183000 - Prelim Survey and Investigation	(73)	785	(859)
0184460 - Captive Insurance Receivable	-	-	-
0186110 - Miscellaneous Work in Process	103,073	101,555	1,519
0186120 - Misc. Wip - Fp Dist. Wids	(225)	2,911	(3,136)
0186290 - Oth Deferred Charges - Operation	0	0	-
0186450 - Error Suspense - Other Product	(4,565,705)	(2,054,512)	(2,511,193)
0186460 - Error Suspense - Mapps(Invoice)	92,758	51,363	41,395
0186470 - Error Suspense - Corp Payroll	-	155	(155)
0186480 - Misc Debits To Be Cleared	279,162	182,252	96,910
0803150 - Med/Heavy Trucks Gvwr > 26K	4,651,704	4,151,318	500,386
0803290 - Miscellaneous Expense	1,756,468,386	1,559,473,688	196,994,699
0803400 - Auto and Truck Exp Distributed	(1,761,121,441)	(1,563,625,907)	(197,495,535)
0830200 - Trenchers and Cable Plows	299	299	-
0830360 - Mobile Equipment	1,052	602	450
0186104 - Deferred Asset-Exit Costs	1,654,366	3,724,281	(2,069,916)
0165022 - Non-Current Prepaid Expenses	-	-	-
0165518 - MW - Prepaid Expenses - LT	-	-	-
1862_OTHER_DEF_DR - Other Deferred Debits	(2,436,644)	2,008,791	(4,445,434)
0804110 - Unproductive Time Distributed	-	11,536	(11,536)
0804210 - Vacations	-	-	-
0804220 - Holidays	-	-	-
0804280 - Scheduled Time Earned Unworked	-	-	-
0804290 - Other Excused Absences	-	-	-
0804330 - Sick	-	-	-

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	December 2020 Actuals	December 2019 Actuals	Variance
1867_ODA_CLR_LBR - Other Deferred Debits - Labor Clearing	-	11,536	(11,536)
0143223 - LT Tax Reclass State Dr	-	857,944	(857,944)
1524_LT_TAX_RCVABLE - Long Term Tax Receivable	-	857,944	(857,944)
0106014 - Intangibles General	-	-	-
1522_INTANG_OTHER - Intangibles, net	-	-	-
Other	149,946,438	(85,398,609)	235,345,047
Total Other Noncurrent Assets	*960,301,439*	*739,318,318*	*220,983,121*
Balance_Account	-	0	0
Total Assets	**2,746,514,350**	**2,494,791,568**	**251,722,782**

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	December 2020 Actuals	December 2019 Actuals	Variance
0232000 - A/P Vendors Payable	-	-	-
0232002 - A/P - Misc - Gen - Acctg	24,893,639	31,156,575	(6,262,936)
0232009 - Purchasing Card Accrual	18,278,636	11,484,491	6,794,146
0232016 - AP PS8.9 Vendors Payable	117,958,870	126,298,968	(8,340,098)
0232018- EAM Payables	170,067,518	229,405,427	(59,337,909)
0232110 - Vouchers Payable - Automated	10,967,973	13,457,468	(2,489,495)
0232120 - Vouchers Payable - Special	28,281,870	20,802,277	7,479,593
0232135 - Employee Expense Payable	0	0	0
0232181 - Natural Gas Payable	-	-	-
0232221 - Employee Relocation - Nei	(101,390)	(165,841)	64,451
0232996 - Capital - Accruals	29,081,680	22,942,473	6,139,207
0242110 - Contract Retentions	946,594	1,923,525	(976,931)
2102_ACCT_PAY_TRADE - Accounts Payable Trade	400,375,392	457,305,364	(56,929,971)
0232061 - Checks not presented - reclass	25,460,014	21,137,700	4,322,315
2104_AP_BANKS - Accounts Payable Banks	25,460,014	21,137,700	4,322,315
Accounts Payable	425,835,407	478,443,063	(52,607,657)
0232232 - A/P Affiliates	10,692,211	10,805,211	(113,000)
2107_AP_CONS_CO - Intercompany Accounts Payable	10,692,211	10,805,211	(113,000)
Accounts payable to affiliated companies	10,692,211	10,805,211	(113,000)
0233150 - IC Moneypool - ST Notes Pay	492,084,000	408,828,000	83,256,000
2204_NOTE_PAY_CONS - Intercompany Notes Payable	492,084,000	408,828,000	83,256,000
Notes payable to affiliated companies	492,084,000	408,828,000	83,256,000
0236981 - Fed Inc Tax Payable - Prev Yr	27,873	-	27,873
0236990 - Fed Inc Tax Payable - Current	278,679	15,343,515	(15,064,836)
2411_ACC_FIT - Accrued Federal Income Taxes	306,551	15,343,515	(15,036,964)
0236001 - State It Payable Other	(114,064)	2,112,024	(2,226,088)
0236965 - Accrued SIT - Prior Year	0	(138,045)	138,045
2412_ACC_SIT - Accrued State Income Taxes	(114,065)	1,973,979	(2,088,043)
0236470 - Franchise Tax Accrual	0	(9)	9
0236840 - Ohio Commercial Activity Tax	(416)	(416)	-
2421_OTHER_ACC_TAX - Other Accrued Taxes	(416)	(425)	9
0236906 - Use Tax Payable	195,135	(57,906)	253,041
2423_ACC_TAX_SLS_USE - Accrued Sales Tax Use	195,135	(57,906)	253,041
0236918 - Accr Ad Valorem Tax 2006	-	-	-
2424_ACC_TAX_PROP - Accrued Property Tax	-	-	-
0236150 - St/Local Unemployment Tax Liab	10,461	23,109	(12,648)
0236700 - Employer FICA Tax Liab	20,800,805	10,271,437	10,529,369
0236750 - Federal Unemployment Tax Liab	2,366	8,435	(6,068)
0241110 - State Income Tax Wh - Employee	1,127,113	245,030	882,083
0241150 - Federal Income Tax Wh - Employee	(11,542)	(107,620)	96,078
0241160 - FICA Withheld - Employee	(2,182)	(16,630)	14,448
0241335 - Local Taxes Withheld	236,398	211,175	25,223
2428_ACC_TAX_PAYROLL - Accrued Payroll Tax	22,163,419	10,634,935	11,528,484
Taxes Accrued	22,550,624	27,894,098	(5,343,474)
0237200 - Curr Interest Accrued	-	-	-
2302_ACC_INT - Interest Accrued - Third Party	-	-	-
0234000 - IC Moneypool - ST Interest Pay	3,548	21,384	(17,835)

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2303_ACC_INT_CONS - Intercompany Interest Accrued	3,548	21,384	(17,835)
Interest Accrued	3,548	21,384	(17,835)
0243103 - Current Cap Lease Oblig - Tax	304,881	128,226	176,655
2156_CLTD_CAP_LEASE - Current Ltd_Cap_Lease	304,881	128,226	176,655
Current Maturities of Long-Term Debt	304,881	128,226	176,655
0232004 - Vision Deduction	(27,581)	(25,841)	(1,740)
0232005 - Long Term Disability Deduction	115,429	113,792	1,637
0232045 - Supplemental Life Deductions	295,449	291,139	4,309
0232048 - Supplemental AD&D Deduction	40,445	39,946	499
0232049 - Medical & HSA Deductions	(291)	135	(426)
0232052 - Medical Spending Acct Deduct	(1)	(1)	-
0232053 - Dependent Spending Acct Deduct	23,434	-	23,434
0232067 - Dental Deductions	(269)	-	(269)
0242381 - Retirement Bank Accrual	4,495,656	5,102,089	(606,433)
0232126 - Accrued Audit Fees	3,742,001	1,679,001	2,063,000
0232230 - Accrued Liabilities	-	-	-
2101_ACCRUED_LIABS - Accrued Liabilities	8,684,272	7,200,262	1,484,011
0242420- Collect For Usa Union	-	-	-
2348_CL_OTH_CUST - Other Current Liabilities - Cust	-	-	-
0242220 - Legal Employee Deductions	7,560	11,402	(3,842)
0242400 - Collections for United Way	330,543	324,521	6,022
0242440 - Cash Coll and Contrib To Trustee	7,243,014	(150,490)	7,393,503
0242450 - Collections From Payroll - Misc	7,984	8,634	(650)
0242460 - Prov For Incentive Ben Prog	81,467,297	149,941,453	(68,474,156)
0242461 - Prior Year Incentive Accrual	(148,614)	-	(148,614)
0242490 - Vacation Carryover	106,675,613	101,576,457	5,099,156
0242660 - Collection - Contr Stk Pur 401 - K	4,112,947	8,859,720	(4,746,773)
0242690 - Executive Incentive Accrual	2,000,000	-	2,000,000
0232039 - Payable 401K Incentive Match	4,666,907	7,689,406	(3,022,499)
0242451- COLLECTIONS-LAUNDRY/UNIFORMS	-	-	-
0242033 - Wages Payable - Accrual	1,823,815	7,593,813	(5,769,998)
2349_CL_OTH_COMP - Other Current Liabilities - Comp	208,187,067	275,854,916	(67,667,849)
0232260 - Deposit Account	918,359	550,464	367,895
0242035 - Unearned Premiums (I)	-	-	-
0242650 - Accrued Payable - Other	-	90	(90)
0242396 - CURR&ACCR LIAB-WORKERS COMP	11,863	11,653	211
0242398 - CURR&ACCR LIAB MISC	16,819	16,819	-
0242175 - Curr Operating Lease Oblig	58,265,045	60,545,455	(2,280,411)
0242185 - ST Oper Lse Obligation Red Hat	0	-	0
2350_OTHER_CURR_LIAB - Other Current Liabities	59,212,086	61,124,481	(1,912,395)
0242215 - Payroll Severance Reserves	3,815,489	14,476,353	(10,660,864)
0242216 - Payrll ST Retention/Spcl Rsrvs	2,589,087	2,953,883	(364,796)
2356_SEVR_RSRV_CLIAB - Severance Reserve	6,404,576	17,430,236	(11,025,660)
0242997 - NQ Pension Current SSERP	2,623,084	2,654,261	(31,177)
0242998 - OPEB Current Liab - Medical	-	403,296	(403,296)
0242999 - Misc Liab - FAS 112	2,038,200	1,748,018	290,182
0242897 - NQ Pension Current ECBP	8,784,125	6,556,900	2,227,225
0242898 - OPEB Current Liab - Life	731,102	240,221	490,881
0242797 - NQ Pension Current FPC SERP/ND	34,090	-	34,090

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2366_OCL_PENSION - Other Current Liab-Pension	14,210,601	11,602,696	2,607,905
Other	296,698,602	373,212,590	(76,513,988)
Total Current Liabilities	*1,248,169,273*	*1,299,332,572*	*(51,163,299)*
0227103 - LT Cap Lease Oblig - Tax Oper	136,060,565	136,365,446	(304,881)
2508_LTD_CAP_LSE - Long-Term Debt - Cap Lse	136,060,565	136,365,446	(304,881)
0181888 - LOC FEE IND PCB 2009A4	-	-	-
1812_UNAMORT_DEBT - Unamortized Debt Expense	-	-	-
Long-Term Debt	*136,060,565*	*136,365,446*	*(304,881)*
Notes payable to affiliated companies	-	-	-
0190001 - Adit: Prepaid: Federal Taxes	(229,369,779)	(185,088,500)	(44,281,279)
0190002 - Adit: Prepaid: State Taxes	(30,067,424)	(24,937,864)	(5,129,560)
0282100 - Adit: PpandE: Federal Taxes	120,602,667	118,186,565	2,416,103
0282101 - Adit: PpandE: State Taxes	16,237,373	16,896,275	(658,902)
0283020 - Valuation Allowance	-	(980,963)	980,963
0283100 - Adit: Other: Federal Taxes	145,954,323	89,802,427	56,151,896
0283101 - Adit: Other: State Taxes	19,650,598	12,229,656	7,420,943
0190051 - Accum Deferred FIT-OCI	(4,205,895)	(4,205,895)	0
0190052 - Accum Deferred SIT-OCI	(566,261)	(566,265)	4
2671_ACC_DFIT - Accumulated Deferred Income Taxes	38,235,603	21,335,436	16,900,167
Deferred Income Taxes	38,235,603	21,335,436	16,900,167
0253690 - Pension Deferred Credits	-	-	-
0254689 - Reg Liability - OPEB Medical	27,830,318	27,252,133	578,185
0254690 - Reg Liability - OPEB Life	(3,258,006)	124,907	(3,382,913)
2647_REG_LIAB_PENSION - Reg Liability - Pension	24,572,312	27,377,040	(2,804,728)
Regulatory Liabilities	24,572,312	27,377,040	(2,804,728)
0227175 - LT Operating Lease Obligation	182,237,950	195,121,808	(12,883,859)
0227185 - LT Oper Lse Obligation Red Hat	-	3,087,467	(3,087,467)
2513_LTD_OP_LSE - Operating Lease Liabilities	182,237,950	198,209,275	(15,971,325)
Operating Lease Liabilities	182,237,950	198,209,275	(15,971,325)
0228314 - OPEB NonCur Liab - Life	18,213,252	6,435,004	11,778,247
0228315 - OPEB NonCur Liab - Medical	44,200,181	61,240,074	(17,039,894)
0228324 - Schm Dpc Pos Emp FAS 112	0	0	-
0228325 - Schm Post Emp FAS 112	14,493,636	11,611,389	2,882,247
0253630 - Schm Exec Cash Bal Plan	130,664,745	128,614,008	2,050,737
0228346 - Pension Liability - FAS 87	251,118,054	-	251,118,054
0228348 - Pension Liab - FAS 87(Cinergy)	0	0	-
0228403 - Deferred Serp - Active Empl	2,565,527	2,324,918	240,609
0228405 - 2000 Class Deferred Compensat	5,729,820	7,851,686	(2,121,866)
0228340 -Nonqualified Plans Liability	24,461,578	25,342,825	(881,247)
2669_ODC_PENSION - Other Deferred Cr - Pension	491,446,792	243,419,905	248,026,888
Accrued Pension and Other Post-Retirement Benefit Costs	491,446,792	243,419,905	248,026,888
0228250 - Inactive - Schm Worker'S Comp - Other	109,236	103,297	5,939
0228280 - Schm Environmental	-	-	-
2650_ODC_INJ_DMG - Other Deferred Cr - Injury/Damage Reserv	109,236	103,297	5,939
0224696 - Other Longterm Liab	228,768	228,768	-
0242803 - Deferred Rent	(2,210,095)	(1,998,470)	(211,624)
0253035 - Misc Def Cr - Genl Acctg	202,219	219,038	(16,819)
0253070 - Reserves - Mgp Sites FERC 228	-	-	-
0253043 - OPEB - FAS106 Grantor Trust	9,724,707	7,615,563	2,109,144

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0228440 - Reserve - MGP Sites FERC 228	-	-	-
0253082 - OTH DEFER CR MISCELLANEOUS	675,655	713,639	(37,984)
0236701 - Employer FICA Tax Liab LT	14,728,217	-	14,728,217
2651_OTHER_DEF_CR - Other Deferred Credits	23,349,472	6,778,538	16,570,934
0236942 - State Inc Tax Payable - Prior Yrs LT	77	77	-
2674_LT_LIAB_UTP - LT Liabilities UTP	77	77	-
Other	23,458,786	6,881,912	16,576,873
Total Other Noncurrent Liabilities	*759,951,442*	*497,223,567*	*262,727,875*
Preferred Stock Redeemable	-	-	-
0201000 - Common Stock Issued	4	4	-
3111_COMMON_STOCK - Common Stock	4	4	-
Common Stock	4	4	-
0208000 - Donations From Stockholder	47,200,000	47,200,000	-
0207008 - Additional Paid In Capital	(2,437,391)	(2,437,391)	-
0211003 - Misc Paid in Capital	214,839,126	214,839,126	-
0208010 - Donat Recvd From Stkhld Tax	(669,224)	(669,224)	-
0211004 - Misc Paid In Capital Purch Acctg	(180,602,490)	(180,602,490)	-
0211005 - Misc Paid In Capital Premerger Equity	(48,887,321)	(48,887,321)	-
3211_ADD_PAID_CAP - Additional Paid in Capital	29,442,700	29,442,700	-
Additional Paid in Capital	29,442,700	29,442,700	-
0216000 - Unapprop Retained Earnings	(44,321,728)	(44,321,728)	-
0216100 - Unappr Undistr Subsid Earnings	592,571,181	552,854,280	39,716,901
0439300 - ADJUST TO R/E	-	(2,803,928)	2,803,928
3311_RET_EARN - Retained Earnings	548,249,453	511,336,480	36,912,973
0439004 - Cumm Effect Acct Change Tax	-	-	-
3511_CEA - Cumulative Effect of Change in Acctg	-	-	-
Current Year Net Income	40,463,088	36,912,973	3,550,115
Retained Earnings	588,712,540	548,249,453	40,463,088
0219020 - FAS 106 actuarial gain or loss	-	-	-
0219101 - OCI - FAS 87 actuarial gain or loss	(20,374,787)	(20,374,787)	-
0219103 - OCI - NQ 87 actuarial gain or loss	(1,707,007)	(1,707,007)	-
0219106 - OCI - FAS 106 actuarial gain or loss	1,995,221	1,995,221	-
0219035 - OCI-Actuarial GL Qual	0	0	-
0219036 - OCI-Actuarial GL Qual Fed Tx	4,161,058	4,161,058	-
0219037 - OCI-Actuarial GL Qual St Tx	560,227	560,227	-
0219038 - OCI-Actuarial GL NQ	(507,764)	(507,764)	-
0219039 - OCI-Actuarial GL NQ Fed Tx	452,313	452,313	-
0219040 - OCI Actuarial GL NQ St Tx	60,899	60,899	-
0219041 - FAS 106 Actuarial GL Fed Tx	(407,476)	(407,476)	-
0219042 - FAS 106 Actuarial GL St Tx	(54,860)	(54,860)	-
ACCUM_OCI_OPEB - Accumulated OCI - Pension and OPEB	(15,822,174)	(15,822,174)	-
OCI Total excluding EPU	(15,822,174)	(15,822,174)	-
Total Other Comprehensive Income	(15,822,174)	(15,822,174)	-
3411_ACCUM_OCI - Accumulated Other Comprehensive Income	(15,822,174)	(15,822,174)	-
Accumulated Other Comprehensive Income	(15,822,174)	(15,822,174)	-
Equity	602,333,070	561,869,982	40,463,088
Total Equity Including Noncontrolling Interest	*602,333,070*	*561,869,982*	*40,463,088*
Total Liabilities and Equity	***2,746,514,350***	***2,494,791,568***	***251,722,782***

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	December 2020 Actuals	December 2019 Actuals	Variance
0456949 - Other Revenue Affiliate	60,897,810	56,734,639	4,163,171
4106_IC_ELEC_REG - Interco Electric Rev - Reg	60,897,810	56,734,639	4,163,171
0417007 - Misc Revenue-Reg	8	(408)	416
0454400 - Other Electric Rents	20,100	20,250	(150)
0456100 - Profit Or Loss on Sale of M&S	-	(1,075)	1,075
4507_OTH_ELEC_REG - Other Electric Revenue Regulated	20,108	18,767	1,341
Regulated Electric	60,917,918	56,753,406	4,164,512
0417000 - Misc Revenue	2,830,997	3,606,984	(775,986)
46XX_OTH_ELEC_REV_NR - Other Electric Rev NonRegulated	2,830,997	3,606,984	(775,986)
0457103 - SC Dir Op Rev Ofst	(58,565,786)	(66,981,864)	8,416,077
0457203 - SC Indr Op Rev Offst	(2,851,105)	(3,626,826)	775,721
0417310 - Products and Svcs - NonReg	(58,658,485)	(66,981,864)	8,323,379
4607_OTH_MISC_REV_NR - Other Misc Rev NonReg	(2,758,407)	(3,626,826)	868,420
Non-Regulated Electric, Natural Gas and Other	72,591	(19,843)	92,433
Total Operating Revenues	60,990,509	56,733,564	4,256,945
0501996 - Fuel Expense	708	-	708
5154_COS_FUEL_COAL - Fuel Cost - Coal	708	-	708
Fuel used in Electric Generation and Purchased Power	708	-	708
0417320 - Exp - Unreg Products and Svcs	326,089	112,094	213,996
0426400 - Exp/Civic and Political Activity	7,079,245	6,775,019	304,226
0426510 - Other	-	165	(165)
0426540 - Employee Service Club Dues	998	553	444
0457700 - Allocated Employee Bnfts Offset	-	4,147	(4,147)
0500000 - Suprvsn and Engrg - Steam Oper	10,569,391	11,811,184	(1,241,794)
0501150 - Coal Handling	1,389	3,575	(2,186)
0502100 - Fossil Steam Exp - Other	805,723	1,410,936	(605,212)
0506000 - Misc Fossil Power Expenses	2,565,609	3,730,393	(1,164,784)
0510000 - Suprvsn and Engrng - Steam Maint	2,018,166	2,488,514	(470,348)
0511000 - Maint of Structures - Steam	378,816	511,114	(132,298)
0512100 - Maint of Boiler Plant - Other	-	8,925	(8,925)
0513100 - Maint of Electric Plant - Other	737,673	639,900	97,773
0528000 - Maint Suprvsn and Enginrng - Nuc	13,420	-	13,420
0535000 - Supervsn and Engrng - Hydro Oper	-	-	-
0543000 - Maint - Reservoir Dam and Waterway	-	776	(776)
0548100 - Generation Expenses - Other Ct	-	78	(78)
0549000 - Misc - Power Generation Expenses	(62,582)	97,706	(160,288)
0553000 - Maint - Gentg and Elect Equip - Ct	6,534	45,077	(38,543)
0554000 - Misc Power Generation Plant - Ct	138	7,951	(7,813)
0557000 - Other Expenses - Oper	366	238	128
0561100 - Load Dispatch - Reliability	14,685	11,817	2,867
0561200 - Load Dispatch - MnitorandOprtrnsys	19,629	16,928	2,701
0561300 - Load Dispatch - TranssvcandSch	2,318	731	1,587
0566000 - Misc Trans Exp - Other	19,249	21,705	(2,456)
0569200 - Maint of Computer Software	20,270	13,642	6,628
0571000 - Maint of Overhead Lines - Trans	-	2,320	(2,320)

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0586000 - Meter Expenses - Dist	193	1,974	(1,781)
0587000 - Cust Install Exp - Other Dist	150	600	(450)
0588100 - Misc Distribution Exp - Other	6,886,693	10,772,381	(3,885,688)
0590000 - Supervsn and Engrng - Dist Maint	-	169	(169)
0593000 - Maint Overhd Lines - Other - Dist	2,925,609	1,879,149	1,046,460
0717000 - Liq Petro Gas Exp - Vapor Proc	-	-	-
0807000 - Gas Purchased Expenses	2,916	11,589	(8,673)
0870000 - Distribution Sys Ops - Supv/Eng	-	569	(569)
0902000 - Meter Reading Expense	2,049	24,080	(22,031)
0903000 - Cust Records and Collection Exp	72,001,761	74,817,270	(2,815,509)
0903100 - Cust Contracts and Orders - Local	634	4,411	(3,777)
0903200 - Cust Billing and Acct	1,651,955	1,941,270	(289,315)
0903250 - Customer Billing - Common	-	-	-
0903300 - Cust Collecting - Local	4,555	4,865	(310)
0903400 - Cust Receiv and Collect Exp - Edp	-	17,761	(17,761)
0905000 - Misc Customer Accts Expenses	-	-	-
0909650 - Misc Advertising Expenses	4,629	3,009	1,620
0910000 - Misc Cust Serv/Inform Exp	57,194	200,285	(143,091)
0910100 - Exp - Rs Reg Prod/Svces - Cstaccts	1,700,308	1,693,638	6,671
0911000 - Supervision	-	5,734	(5,734)
0912000 - Demonstrating and Selling Exp	14,089	81,181	(67,092)
0913001 - Advertising Expense	7,996	80,993	(72,997)
0916000 - Miscellaneous Sales Expense	5,969,971	5,211,807	758,164
0926000 - Employee Benefits	227,525,122	227,051,333	473,789
0926420 - Employees' Tuition Refund	777	40	737
0926600 - Employee Benefits - Transferred	469,380,303	534,232,652	(64,852,350)
0581004 - Load Dispatch-Dist of Elec	1,132	1,005	127
0457102 - SC Direct O&M Offst	(661,700,218)	(720,998,639)	59,298,421
0457202 - SC Indirect O&M Ofst	(206,972,166)	(218,330,949)	11,358,783
0510100 - Suprvsn and Engrng-Steam Maint - Rec	-	271	(271)
0908000 - Cust Asst Exp-Conservation Programs - Rec	720	4,799	(4,078)
0912200 - EV Employee Incentive	(12,000)	15,000	(27,000)
52XX_OPER_EX - Operating Expenses	(56,028,499)	(53,556,263)	(2,472,236)
0932000 - Maintenance of General Plant	-	(1,838)	1,838
53XX_REPAIR_MAINT - Repairs and Maintenance	-	(1,838)	1,838
0924050 - Intercompany Property Insurance Exp	346,960	290,091	56,869
0931008 - A and G Rents IC	34,767,405	35,291,402	(523,996)
6X05_CON_GEN_ADMIN - Intercompany Admin and General Expenses	35,114,365	35,581,493	(467,128)
0426100 - Donations	3,331,161	3,068,250	262,912
0920000 - A and G Salaries	407,781,437	411,136,437	(3,354,999)
0921100 - Employee Expenses	4,399,467	16,867,396	(12,467,929)
0921200 - Office Expenses	46,053,795	58,936,071	(12,882,276)
0921300 - Telephone and Telegraph Exp	22,657	80,526	(57,869)
0921400 - Computer Services Expenses	32,820,518	39,287,279	(6,466,761)
0921540 - Computer Rent (Go Only)	60,482,968	57,371,143	3,111,824
0921600 - Other	21,302	52,635	(31,332)
0921980 - Office Supplies and Expenses	463,085,717	593,957,286	(130,871,570)

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0922000 - Admin Exp Transfer	(270)	78,976	(79,246)
0923000 - Outside Services Employed	142,267,658	145,012,734	(2,745,076)
0923980 - Outside Services Employee and	3,551,650	2,817,223	734,427
0924000 - Property Insurance	200,606	180,872	19,734
0924980 - Property Insurance For Corp.	13,333,003	13,373,205	(40,202)
0925000 - Injuries and Damages	10,615	11,838	(1,223)
0925200 - Injuries and Damages - Other	536,356	563,255	(26,898)
0925980 - Injuries and Damages For Corp.	1,432,919	1,387,903	45,016
0928000 - Regulatory Expenses (Go)	12,000	-	12,000
0928030 - Prof Fees Consultant	-	(3,364)	3,364
0930150 - Miscellaneous Advertising Exp	2,095,155	1,133,760	961,395
0930200 - Misc General Expenses	(181,045,894)	(174,469,729)	(6,576,164)
0930210 - Industry Association Dues	-	3,229,131	(3,229,131)
0930220 - Exp of Servicing Securities	(427,729)	(39,623)	(388,106)
0930230 - Dues To Various Organizations	642,976	359,951	283,025
0930240 - Director'S Expenses	4,588,042	5,105,863	(517,821)
0930250 - Buy\Sell Transf Employee Homes	905,184	1,075,567	(170,383)
0930600 - Leased Circuit Charges - Other	-	57	(57)
0930700 - Research and Development	39,095	189,290	(150,194)
0930940 - General Expenses	198,563	233,694	(35,131)
0935100 - Maint General Plant-Elec	382,636	328,097	54,538
0935200 - Cust Infor and Computer Control	195,544	67,310	128,234
0107888 - CWIP - BU Bal Sht - Svc Co Exp	1,383,033,297	1,281,370,361	101,662,936
0931001 - Rents - AandG	32,444,180	30,613,525	1,830,655
0108888 - RWIP - BU Bal Sht - Svc Co Exp	8,268,597	8,996,668	(728,071)
0163888 - Stores Expense - BU Bal Sht - SvcCo Exp	112,209,766	101,345,471	10,864,295
0182888 - Oth Reg Assets - BU Bal Sht - SvcCo Exp	10,248,216	7,694,100	2,554,116
0183888 - Prelim Srvy&Invest - BU Bal Sht - SvcCo Exp	1,213,525	1,080,512	133,013
0184888 - Clearing Acct - BU Bal Sht - SvcCo Exp	42,797	(4,230,738)	4,273,536
0186888 - Misc Def Dbt - BU Bal Sht - SvcCo Exp	77,394,630	90,778,755	(13,384,125)
0121888 - Non-Util Prpty BU B/S SC Exp	(966,086)	7,044,540	(8,010,626)
0185888 - Temp Facil - BU B/S-SvcCoExp	(67,783)	(823,072)	755,288
0921110 - Relocation Expenses	14,127	1,334	12,794
0457101 - SC Direct A&G Offst	(1,998,347,794)	(2,033,554,913)	35,207,119
0457201 - SC Indirect A&G Ofst	(825,355,750)	(839,695,450)	14,339,700
0920100 - Salaries & Wages - Proj Supt - NCRC Rec	2,180	67,797	(65,617)
0923100 - Outside Svcs Cont -Proj Supt - NCRC Rec	7,304	-	7,304
0921101 - Employee Exp - NC	1,083	2,033	(950)
0426300 - Penalties	-	2,252	(2,252)
0931003 - Lease Amortization Expense	(26,417)	371,600	(398,017)
0920001 - SC O&M Labor Deferral	64,134	-	64,134
6XXX_GEN_ADMIN - Administrative and General Expenses	(192,902,862)	(167,542,193)	(25,360,670)
Operations, Maintenance and Other	(213,816,997)	(185,518,801)	(28,298,196)
0403500 - Depr of General Plant	203,654,794	174,028,592	29,626,202
0403360 - Lease-Depr In rate base Plt IC	-	-	-
540X_DDA_PPE - Depreciation and Depletion	203,654,794	174,028,592	29,626,202
Depreciation and Amortization	203,654,794	174,028,592	29,626,202

Duke Energy Business Services

Working Trial Balance
December 2020
Year-to-Date

	December 2020 Actuals	December 2019 Actuals	Variance
0408040 - NC Property Tx - Misc NonUtility	6,851,447	6,625,546	225,900
0408120 - Franchise Tax - Non Electric	-	968	(968)
0408150 - State Unemployment Tax	464,434	483,214	(18,781)
0408151 - Federal Unemployment Tax	(114,428)	404,874	(519,303)
0408152 - Employer FICA Tax	56,930,521	62,505,897	(5,575,377)
0408153 - Employer Local Tax	-	4,934	(4,934)
0408470 - Franchise Tax	1,765,253	2,239,051	(473,798)
0408800 - Federal Highway Use Tax - Elec	1,100	51,593	(50,493)
0408820 - Misc NonUtility Tax	-	111	(111)
0408851 - Sales and Use Tax Exp	(5,446,639)	(424,353)	(5,022,285)
0408960 - Allocated Payroll Taxes	(23,047,176)	(24,801,807)	1,754,630
0457200 - SC Indirect PT Offst	(25,378,429)	(32,061,619)	6,683,189
0408205 - Highway Use Tax	58,393	59,689	(1,296)
0457104 - SC Direct PT Offst	(13,073,536)	(15,088,744)	2,015,208
55XX_MISC_TAX - Miscellaneous Taxes	(989,062)	(645)	(988,417)
Property and Other Taxes	(989,062)	(645)	(988,417)
Total Operating Expenses	(11,150,556)	(11,490,853)	340,297
0421100 - Gain on Disposal of Property	-	29	(29)
0421200 - Loss on Disposal of Property	-	(1,285,701)	1,285,701
0421114 - Gain/Loss on Leases	-	(3,278)	3,278
7519_GAINLOSS_PPE - PpandE Gain (Loss)	-	(1,282,393)	1,282,393
Gain/(Loss) on Sales of Other Assets and Other, net	-	(1,282,393)	1,282,393
Other Operating Gains and Losses	-	(1,282,393)	1,282,393
Operating Income	72,141,065	66,942,024	5,199,041
0421940 - Misc Income	(21,030,228)	(16,265,802)	(4,764,425)
0426200 - Life Insurance Expense	(151,043)	(162,458)	11,415
0457988 - Allocated other income or exp offset	(6,905,626)	(7,675,513)	769,888
0926999 - Non Service Cost (ASU 2017-07)	(27,784,810)	(23,778,858)	(4,005,952)
71XX_OTHER_INCOME - Other Income	0	0	0
0419240 - Miscellaneous Interest	653,488	(2,055)	655,542
7310_INT_DIV - Interest and Dividends	653,488	(2,055)	655,542
0419429 - IC Moneypool - Interest Inc	-	-	-
7330_INTERCO_INT - Intercompany Interest Income	-	-	-
Other Income and Expenses	653,487	(2,054)	655,542
Earnings Before Interest Expense and Taxes	72,794,552	66,939,969	5,854,583
0431400 - Int/Other Notes and Acct Pay	233,733	324,085	(90,352)
8220_INT_OTHER_DEBT - Interest on Other Debt	233,733	324,085	(90,352)
0431000 - Int Exp - Taxes	(159,417)	1,126	(160,543)
0431002 - Int Exp - Other	-	6,081,706	(6,081,706)
0431130 - Interest Exp - Capital Lease	10,506,153	4,380,453	6,125,700
8410_MISC_INT_EXP - Miscellaneous Interest Expense	10,346,736	10,463,285	(116,549)
0430216 - IC Moneypool - Interest Exp	4,121,443	10,702,309	(6,580,866)
8430_INTERCO_INT - Intercompany Interest Expense	4,121,443	10,702,309	(6,580,866)
0457301 - SC Ind Intrst Offset	(3,704,934)	(11,031,169)	7,326,235
8510_INT_COST_CAP - Interest Costs on Capital Debt Expense	(3,704,934)	(11,031,169)	7,326,235
Interest Expense	10,996,977	10,458,509	538,468
Earnings From Continuing Operations Before Income Taxes	61,797,575	56,481,460	5,316,115

Duke Energy Business Services

Working Trial Balance
December 2020
Year-to-Date

	December 2020 Actuals	December 2019 Actuals	Variance
0409220 - Federal Income Tax - NonUtility CY	278,679	15,343,515	(15,064,836)
0409221 - Federal Income Tax - NonUtility PY	3,168,374	1,975,437	1,192,937
8611_CURR_FIT - Current Federal Income Taxes	3,447,052	17,318,951	(13,871,899)
0409202 - State Income Tax NonUtility	37,924	2,112,024	(2,074,100)
0409233 - Tax expense - state nonutility - PY	297,747	(5,367)	303,114
0409297- Current State Inc Tax-Non Util	-	-	-
8612_CURR_SIT - Current State Income Taxes	335,671	2,106,657	(1,770,987)
0410240 - Dfit: Non - Utility: Curr Year	124,134,378	111,185,935	12,948,443
0410241 - Dfit: Non - Utility: Prior Yr Cr	5,978,485	1,061,898	4,916,586
0411240 - Dfit: Non - Utility: Curr Yr Cr	(104,943,491)	(109,620,586)	4,677,096
0411241 - Other Deferred Taxes PY	(9,069,713)	(2,501,323)	(6,568,390)
8621_DEF_FIT - Deferred Federal Income Taxes	16,099,659	125,925	15,973,734
0410242 - Dsit: Non - Utility: Curr Year	16,868,998	14,969,547	1,899,450
0410243 - Dsit: Non - Utility: Prior Year	804,915	142,969	661,946
0411242 - Dsit: Non - Utility: Curr Yr Cr	(15,081,048)	(14,758,796)	(322,252)
0411243 - Dsit: Non - Utility: Prior Yr Cr	(1,140,838)	(336,766)	(804,072)
8622_DEF_SIT - Deferred State Income Taxes	1,452,026	16,954	1,435,072
Income Tax Expense (Benefit) From Continuing Operations	21,334,408	19,568,487	1,765,921
Income From Continuing Operations Attributable to Duke Energy Corp	40,463,167	36,912,973	3,550,194
Income (Loss) From Continuing Operations	40,463,167	36,912,973	3,550,194
4181107 - Earnings of Sub	(79)	-	(79)
7210_EQ_SUBS - Earnings of Subsidiaries	(79)	-	(79)
Earnings (Loss) of Subsidiaries	(79)	-	(79)
Net Inc Bfr Ext and Chg in Acct. Prin.	40,463,088	36,912,973	3,550,115
Consolidated Net Income	40,463,088	36,912,973	3,550,115
Net Income Attributable to Company	40,463,088	36,912,973	3,550,115
Net Income Attributable to Controlling Interest	**40,463,088**	**36,912,973**	**3,550,115**

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-026

REQUEST:

Provide the Company's average daily short-term investment balances and the average interest rates on those balances in the Money Pool each month from January 2018 through December 2022 in an Excel spreadsheet in live format and with all formulas intact.

RESPONSE:

Please see AG-DR-02-026 Attachment for the requested Duke Energy Money Pool information. Note that the forecast is developed on a monthly basis. Therefore, the forecasted information is monthly only.

PERSON RESPONSIBLE: Chris R. Bauer

Money Pool Borrowings - Including $25 million long-term balance

Historical Information:

	Daily Average Borrowings	Rate
Jan-18	$ 26,088,967.74	1.745%
Feb-18	$ 28,214,964.29	1.789%
Mar-18	$ 30,558,806.45	2.020%
Apr-18	$ 59,500,333.33	2.282%
May-18	$ 87,583,677.42	2.207%
Jun-18	$ 107,135,933.33	2.230%
Jul-18	$ 106,836,870.97	2.228%
Aug-18	$ 111,937,870.97	2.148%
Sep-18	$ 100,815,233.33	2.141%
Oct-18	$ 81,857,677.42	2.355%
Nov-18	$ 72,058,566.67	2.424%
Dec-18	$ 71,300,774.19	2.656%
Jan-19	$ 55,218,451.61	2.729%
Feb-19	$ 64,345,892.86	2.721%
Mar-19	$ 65,006,677.42	2.692%
Apr-19	$ 74,713,900.00	2.685%
May-19	$ 79,345,225.81	2.678%
Jun-19	$ 86,648,266.67	2.635%
Jul-19	$ 102,508,516.13	2.563%
Aug-19	$ 78,744,516.13	2.345%
Sep-19	$ 85,334,833.33	2.233%
Oct-19	$ 42,708,806.45	2.095%
Nov-19	$ 62,909,766.67	1.833%
Dec-19	$ 95,159,612.90	1.830%
Jan-20	$ 104,274,935.48	1.766%
Feb-20	$ 100,528,892.86	1.716%
Mar-20	$ 101,341,903.23	1.742%
Apr-20	$ 109,197,300.00	1.317%
May-20	$ 105,227,612.90	0.729%
Jun-20	$ 106,890,366.67	0.292%
Jul-20	$ 106,720,258.06	0.239%
Aug-20	$ 120,197,387.10	0.212%
Sep-20	$ 92,832,233.33	0.180%
Oct-20	$ 61,363,451.61	0.213%
Nov-20	$ 75,670,600.00	0.219%
Dec-20	$ 92,094,032.26	0.248%
Jan-21	$ 88,858,677.42	0.242%
Feb-21	$ 99,610,607.14	0.202%
Mar-21	$ 100,863,741.94	0.195%
Apr-21	$ 94,409,366.67	0.157%
May-21	$ 88,752,870.97	0.163%
Jun-21	$ 70,261,966.67	0.165%

Forecasted information:

	Daily Average and End of Month Borrowings	Rate
Jul-21	115,587,004	0.1668%
Aug-21	114,577,642	0.1792%
Sep-21	25,000,000	0.1915%
Oct-21	25,000,000	0.1915%
Nov-21	25,000,000	0.2224%
Dec-21	25,000,000	0.2513%
Jan-22	25,000,000	0.2513%
Feb-22	25,000,000	0.2336%
Mar-22	25,000,000	0.2146%
Apr-22	25,000,000	0.2146%
May-22	25,000,000	0.2367%
Jun-22	25,898,283	0.2587%
Jul-22	33,334,072	0.2587%
Aug-22	36,234,630	0.2980%
Sep-22	25,000,000	0.3899%
Oct-22	25,000,000	0.3899%
Nov-22	25,000,000	0.3899%
Dec-22	25,000,000	0.3899%

Issuer	Borrower	Settlement	Maturity	Maturity Month	Maturity Year	Combined	Term in Period	Rate	Rate in %	Principal	Interest in Period	Weighted ParValue
						1 2018 Total			1.78%			$808,758,000.00
						2 2018 Total			1.82%			$790,019,000.00
						3 2018 Total			2.31%			$947,323,000.00
						4 2018 Total			2.31%			$1,785,010,000.00
						5 2018 Total			2.21%			$2,715,094,000.00
						6 2018 Total			1.91%			$3,214,078,000.00
						7 2018 Total			1.94%			$3,311,943,000.00
						8 2018 Total			2.19%			$3,470,074,000.00
						9 2018 Total			2.12%			$3,024,457,000.00
						10 2018 Total			2.42%			$2,537,588,000.00
						11 2018 Total			2.56%			$2,161,757,000.00
						12 2018 Total			2.79%			$2,210,324,000.00
						1 2019 Total			2.76%			$1,711,772,000.00
						2 2019 Total			2.77%			$1,801,685,000.00
						3 2019 Total			2.70%			$2,015,207,000.00
						4 2019 Total			2.68%			$2,241,417,000.00
						5 2019 Total			2.67%			$2,459,702,000.00
						6 2019 Total			2.32%			$2,599,448,000.00
						7 2019 Total			2.53%			$3,177,764,000.00
						8 2019 Total			2.30%			$2,441,080,000.00
						9 2019 Total			2.19%			$2,560,045,000.00
						10 2019 Total			2.03%			$1,323,973,000.00
						11 2019 Total			1.84%			$1,887,293,000.00
						12 2019 Total			1.91%			$2,949,948,000.00
						1 2020 Total			1.78%			$3,232,523,000.00
						2 2020 Total			1.77%			$2,814,809,000.00
						3 2020 Total			2.25%			$3,141,599,000.00
						4 2020 Total			1.47%			$3,275,919,000.00
						5 2020 Total			0.52%			$3,262,056,000.00
						6 2020 Total			0.27%			$3,206,711,000.00
						7 2020 Total			0.26%			$3,308,328,000.00
						8 2020 Total			0.24%			$3,726,119,000.00
						9 2020 Total			0.23%			$2,784,967,000.00
						10 2020 Total			0.22%			$1,902,267,000.00
						11 2020 Total			0.23%			$2,270,118,000.00
						12 2020 Total			0.26%			$2,854,915,000.00
						1 2021 Total			0.22%			$2,754,619,000.00
						2 2021 Total			0.20%			$2,789,097,000.00
						3 2021 Total			0.04%			$3,126,776,000.00
						4 2021 Total			0.03%			$2,832,281,000.00
						5 2021 Total			0.01%			$2,751,339,000.00
						6 2021 Total			0.17%			$2,107,859,000.00
						Grand Total						$79,311,636,000.00

Days in Month	Daily Average	Month End	Weight	Daily Wtd Avg
31	26,088,967.74	$35,898,000.00	100.00%	1.75%
28	28,214,964.29	$36,129,000.00	100.00%	1.79%
31	30,558,806.45	$57,252,000.00	100.00%	2.02%
30	59,500,333.33	$202,825,000.00	100.00%	2.28%
31	87,583,677.42	$117,951,000.00	100.00%	2.21%
30	107,135,933.33	$100,430,000.00	100.00%	2.23%
31	106,836,870.97	$120,744,000.00	100.00%	2.23%
31	111,937,870.97	$114,939,000.00	100.00%	2.15%
30	100,815,233.33	$127,181,000.00	100.00%	2.14%
31	81,857,677.42	$79,316,000.00	100.00%	2.35%
30	72,058,566.67	$93,030,000.00	100.00%	2.42%
31	71,300,774.19	$131,797,000.00	100.00%	2.66%
31	55,218,451.61	$75,233,000.00	100.00%	2.73%
28	64,345,892.86	$72,972,000.00	100.00%	2.72%
31	65,006,677.42	$74,603,000.00	100.00%	2.69%
30	74,713,900.00	$82,874,000.00	100.00%	2.68%
31	79,345,225.81	$93,586,000.00	100.00%	2.68%
30	86,648,266.67	$112,621,000.00	100.00%	2.64%
31	102,508,516.13	$88,558,000.00	100.00%	2.56%
31	78,744,516.13	$96,225,000.00	100.00%	2.34%
30	85,334,833.33	$75,000,000.00	100.00%	2.23%
31	42,708,806.45	$64,554,000.00	100.00%	2.09%
30	62,909,766.67	$169,506,000.00	100.00%	1.83%
31	95,159,612.90	$109,862,000.00	100.00%	1.83%
31	104,274,935.48	$110,524,000.00	100.00%	1.77%
28	100,528,892.86	$102,386,000.00	100.00%	1.72%
31	101,341,903.23	$116,581,000.00	100.00%	1.74%
30	109,197,300.00	$118,498,000.00	100.00%	1.32%
31	105,227,612.90	$120,979,000.00	100.00%	0.73%
30	106,890,366.67	$102,394,000.00	100.00%	0.29%
31	106,720,258.06	$127,207,000.00	100.00%	0.24%
31	120,197,387.10	$392,439,000.00	100.00%	0.21%
30	92,832,233.33	$64,831,000.00	100.00%	0.18%
31	61,363,451.61	$75,016,000.00	100.00%	0.21%
30	75,670,600.00	$270,924,000.00	100.00%	0.22%
31	92,094,032.26	$101,783,000.00	100.00%	0.25%
31	88,858,677.42	$104,174,000.00	100.00%	0.24%
28	99,610,607.14	$105,157,000.00	100.00%	0.20%
31	100,863,741.94	$106,804,000.00	100.00%	0.20%
30	94,409,366.67	$106,432,000.00	100.00%	0.16%
31	88,752,870.97	$108,363,000.00	100.00%	0.16%
30	70,261,966.67	$53,848,000.00	100.00%	0.17%

$000s

	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Moneypool Payable	90,587	89,578	0	0	0	0	0	0	0	0	0	898	8,334	11,235	0	0	0	0
CP LT Debt	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
	115,587,004	114,577,642	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,898,283	33,334,072	36,234,630	25,000,000	25,000,000	25,000,000	25,000,000

Rate — Forward 1 month LIBOR pulled from Bloomberg. See AG-DR-01-043 Attachments 4 and 5 for the Bloomberg screenshots

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-027

REQUEST:

Provide separately the Company's regulatory assets and liabilities related to pension and OPEB by month from January 2018 through the end of the test year by FERC account/subaccount in total and allocated to gas and the gas share of common. Provide a detailed description of each regulatory asset and liability and how it is calculated. Indicate whether the Company financed or avoided financing as a result of the regulatory asset or liability and, if so, provide all support for your position. In addition, provide all reasons why the Company did not include the net liability as a subtraction from rate base and removed all related ADIT balances from rate base.

RESPONSE:

Please see AG-DR-02-027 Attachment. The net balance of pension and OPEB is a net asset of $3,626,331 as of December 31, 2022 ($3,649,323 13-month average). The Company has not historically included the pension and OPEB regulatory assets as part of rate base, but if it did so, it would be an increase to rate base, not a subtraction from rate base as the question suggest. Regulatory assets and liabilities, which simply represent deferred gains/losses, are not considered when making financing decisions. Financing decisions are made when assessing a plan's Funded Status in accordance with funding rules.

PERSON RESPONSIBLE: Jay P. Brown

DUKE ENERGY KENTUCKY

Pension	FERC 128 Total	FERC 128 Gas	FERC 182.3 Total	FERC 182.3 Gas	FERC 186 Total	FERC 186 Gas	FERC 228.3 Total	FERC 228.3 Gas
Jan 2018	1,256,346	345,998	32,090,706	8,837,781	-	-	-	-
Feb 2018	7,653,020	2,107,642	31,989,601	8,809,936	-	-	(18,259,243)	(5,028,596)
Mar 2018	7,723,986	2,127,186	31,834,834	8,767,313	-	-	(18,259,243)	(5,028,596)
Apr 2018	7,794,952	2,146,730	31,680,067	8,724,691	-	-	(18,259,243)	(5,028,596)
May 2018	7,865,918	2,166,274	31,525,300	8,682,068	-	-	(18,259,243)	(5,028,596)
Jun 2018	8,556,406	2,356,434	31,370,533	8,639,445	-	-	(18,878,765)	(5,199,212)
Jul 2018	8,007,850	2,205,362	31,215,766	8,596,822	-	-	(18,259,243)	(5,028,596)
Aug 2018	8,078,816	2,224,906	31,060,999	8,554,199	-	-	(18,259,243)	(5,028,596)
Sep 2018	9,115,105	2,510,300	30,906,232	8,511,576	-	-	(19,224,566)	(5,294,445)
Oct 2018	8,220,748	2,263,994	30,751,465	8,468,954	-	-	(18,259,243)	(5,028,596)
Nov 2018	8,291,714	2,283,538	30,596,698	8,426,331	-	-	(18,259,243)	(5,028,596)
Dec 2018	7,330,598	2,018,847	29,647,881	8,165,027	-	-	(16,433,111)	(4,525,679)
Jan 2019	6,010,124	1,450,243	29,647,881	7,154,034	-	-	(15,121,987)	(3,648,935)
Feb 2019	6,218,072	1,500,421	29,474,155	7,112,114	-	-	(15,121,987)	(3,648,935)
Mar 2019	7,894,787	1,905,012	29,387,292	7,091,154	-	-	(16,699,403)	(4,029,566)
Apr 2019	6,594,198	1,591,180	29,300,429	7,070,194	-	-	(15,299,515)	(3,691,773)
May 2019	6,782,261	1,636,560	29,213,566	7,049,234	-	-	(15,388,279)	(3,713,192)
Jun 2019	8,458,976	2,041,151	33,732,306	8,139,605	243,841	58,839	(21,609,612)	(5,214,399)
Jul 2019	7,158,387	1,727,319	33,606,342	8,109,210	241,757	58,336	(20,219,701)	(4,879,014)
Aug 2019	7,346,450	1,772,698	33,480,378	8,078,815	239,673	57,833	(20,318,442)	(4,902,840)
Sep 2019	9,023,165	2,177,290	36,422,208	8,788,679	315,677	76,173	(24,492,922)	(5,910,142)
Oct 2019	8,203,465	1,979,496	36,278,079	8,753,900	312,925	75,509	(23,579,887)	(5,689,827)
Nov 2019	8,391,528	2,024,876	36,133,950	8,719,122	310,174	74,845	(23,674,615)	(5,712,685)
Dec 2019	9,774,894	2,358,682	34,157,339	8,242,166	350,062	84,470	(23,593,846)	(5,693,195)
Jan 2020	9,715,563	2,580,454	34,157,339	9,072,189	350,062	92,977	(23,593,846)	(6,266,526)
Feb 2020	10,221,864	2,714,927	33,826,775	8,984,391	343,830	91,321	(23,774,372)	(6,314,473)
Mar 2020	10,445,349	2,774,285	33,661,493	8,940,493	-	-	(23,864,635)	(6,338,447)
Apr 2020	10,668,834	2,833,642	33,496,211	8,896,594	-	-	(23,954,898)	(6,362,421)
May 2020	10,892,319	2,893,000	33,330,929	8,852,695	-	-	(24,045,161)	(6,386,395)
Jun 2020	11,115,804	2,952,358	33,223,925	8,824,274	-	-	(24,135,424)	(6,410,369)
Jul 2020	11,339,289	3,011,715	33,068,356	8,782,955	-	-	(24,225,687)	(6,434,343)
Aug 2020	11,562,774	3,071,073	32,912,787	8,741,636	-	-	(24,315,950)	(6,458,316)
Sep 2020	11,786,259	3,130,430	32,757,218	8,700,317	-	-	(24,406,213)	(6,482,290)
Oct 2020	12,009,744	3,189,788	32,601,649	8,658,998	-	-	(24,496,476)	(6,506,264)
Nov 2020	12,233,229	3,249,146	32,446,080	8,617,679	-	-	(24,586,739)	(6,530,238)
Dec 2020	12,851,866	3,413,456	34,029,604	9,038,263	-	-	(26,811,247)	(7,121,067)
Jan 2021	12,829,565	3,635,899	34,029,604	9,643,990	-	-	(26,811,247)	(7,598,307)

DUKE ENERGY KENTUCKY

Pension	FERC 128 Total	FERC 128 Gas	FERC 182.3 Total	FERC 182.3 Gas	FERC 186 Total	FERC 186 Gas	FERC 228.3 Total	FERC 228.3 Gas
Feb 2021	13,347,730	3,782,747	33,692,432	9,548,435	-	-	(26,979,805)	(7,646,077)
Mar 2021	13,595,662	3,853,011	33,523,846	9,500,658	-	-	(27,064,084)	(7,669,961)
Apr 2021	13,843,594	3,923,275	33,355,260	9,452,881	-	-	(27,148,363)	(7,693,846)
May 2021	14,091,526	3,993,538	33,186,674	9,405,103	-	-	(27,232,642)	(7,717,731)
Jun 2021	14,339,458	4,063,802	33,018,088	9,357,326	-	-	(27,316,921)	(7,741,615)
Jul 2021	14,587,390	4,134,066	32,849,502	9,309,549	-	-	(27,401,200)	(7,765,500)
Aug 2021	14,835,322	4,204,330	32,680,916	9,261,772	-	-	(27,485,479)	(7,789,385)
Sep 2021 (estimated)	15,083,254	4,274,594	32,512,330	9,213,994	-	-	(27,569,758)	(7,813,269)
Oct 2021 (estimated)	15,331,186	4,344,858	32,343,744	9,166,217	-	-	(27,654,037)	(7,837,154)
Nov 2021 (estimated)	15,579,118	4,415,122	32,175,158	9,118,440	-	-	(27,738,316)	(7,861,039)
Dec 2021 (estimated)	15,827,050	4,485,386	32,006,572	9,070,663	-	-	(27,822,595)	(7,884,923)
Jan 2022 (estimated)	16,162,628	4,580,489	31,763,325	9,001,726	-	-	(27,897,783)	(7,906,232)
Feb 2022 (estimated)	16,162,628	4,580,489	31,763,325	9,001,726	-	-	(27,897,783)	(7,906,232)
Mar 2022 (estimated)	16,075,479	4,555,791	31,763,325	9,001,726	-	-	(27,897,783)	(7,906,232)
Apr 2022 (estimated)	16,075,479	4,555,791	31,763,325	9,001,726	-	-	(27,897,783)	(7,906,232)
May 2022 (estimated)	16,075,479	4,555,791	32,098,903	9,096,829	-	-	(28,053,881)	(7,950,470)
Jun 2022 (estimated)	16,075,479	4,555,791	32,098,903	9,096,829	-	-	(28,053,881)	(7,950,470)
Jul 2022 (estimated)	16,075,479	4,555,791	32,011,754	9,072,131	-	-	(28,053,881)	(7,950,470)
Aug 2022 (estimated)	16,075,479	4,555,791	32,011,754	9,072,131	-	-	(28,053,881)	(7,950,470)
Sep 2022 (estimated)	16,075,479	4,555,791	32,011,754	9,072,131	-	-	(27,718,303)	(7,855,367)
Oct 2022 (estimated)	16,075,479	4,555,791	32,011,754	9,072,131	-	-	(27,718,303)	(7,855,367)
Nov 2022 (estimated)	16,075,479	4,555,791	32,011,754	9,072,131	-	-	(27,805,452)	(7,880,065)
Dec 2022 (estimated)	16,075,479	4,555,791	32,011,754	9,072,131	-	-	(27,805,452)	(7,880,065)

OPEB	FERC 182.3 Total	FERC 182.3 Gas	FERC 228.3 Total	FERC 228.3 Gas	FERC 254 Total	FERC 254 Gas
Jan 2018	-	-	(4,486,623)	(1,235,616)	(4,832,653)	(1,330,913)
Feb 2018	(42,570)	(11,724)	(4,467,984)	(1,230,483)	(4,798,435)	(1,321,489)
Mar 2018	(63,855)	(17,586)	(4,467,008)	(1,230,214)	(4,781,326)	(1,316,777)
Apr 2018	(85,140)	(23,448)	(4,467,840)	(1,230,443)	(4,764,217)	(1,312,065)
May 2018	(106,425)	(29,309)	(4,462,328)	(1,228,925)	(4,747,108)	(1,307,353)
Jun 2018	(127,710)	(35,171)	(4,469,319)	(1,230,851)	(4,729,999)	(1,302,642)
Jul 2018	(148,995)	(41,033)	(4,473,720)	(1,232,062)	(4,712,890)	(1,297,930)
Aug 2018	(170,280)	(46,895)	(4,471,488)	(1,231,448)	(4,695,781)	(1,293,218)
Sep 2018	(191,565)	(52,757)	(4,489,203)	(1,236,327)	(4,678,672)	(1,288,506)
Oct 2018	(212,850)	(58,619)	(4,496,234)	(1,238,263)	(4,661,563)	(1,283,794)

DUKE ENERGY KENTUCKY

Pension	FERC 128 Total	FERC 128 Gas	FERC 182.3 Total	FERC 182.3 Gas	FERC 186 Total	FERC 186 Gas	FERC 228.3 Total	FERC 228.3 Gas
Nov 2018	(234,135)	(64,481)	(4,834,190)	(1,331,336)	(4,644,454)	(1,279,083)		
Dec 2018	(255,420)	(70,343)	(4,042,983)	(1,113,437)	(5,205,637)	(1,433,632)		
Jan 2019	(255,420)	(61,633)	(4,028,937)	(972,182)	(5,205,637)	(1,256,120)		
Feb 2019	(294,044)	(70,953)	(4,023,711)	(970,921)	(5,168,779)	(1,247,226)		
Mar 2019	2,016,838	486,663	(4,035,536)	(973,775)	(5,150,350)	(1,242,779)		
Apr 2019	1,997,526	482,003	(4,019,189)	(969,830)	(5,131,921)	(1,238,332)		
May 2019	1,978,214	477,343	(4,022,031)	(970,516)	(5,113,492)	(1,233,886)		
Jun 2019	1,958,902	472,683	(4,032,776)	(973,109)	(5,095,063)	(1,229,439)		
Jul 2019	1,939,590	468,023	(4,026,198)	(971,522)	(5,076,634)	(1,224,992)		
Aug 2019	1,920,278	463,363	(4,034,264)	(973,468)	(5,058,205)	(1,220,545)		
Sep 2019	1,900,966	458,703	(4,054,017)	(978,234)	(5,039,776)	(1,216,098)		
Oct 2019	1,881,654	454,043	(4,029,965)	(972,430)	(5,021,347)	(1,211,651)		
Nov 2019	1,862,342	449,383	(4,385,294)	(1,058,172)	(5,002,918)	(1,207,204)		
Dec 2019	1,843,030	444,723	(3,870,613)	(933,979)	(5,328,516)	(1,285,771)		
Jan 2020	1,843,030	489,509	(3,852,330)	(1,023,179)	(5,328,516)	(1,415,254)		
Feb 2020	1,808,262	480,274	(3,845,187)	(1,021,282)	(5,292,954)	(1,405,809)		
Mar 2020	1,790,878	475,657	(3,834,243)	(1,018,375)	(5,275,173)	(1,401,086)		
Apr 2020	1,773,494	471,040	(3,803,974)	(1,010,336)	(5,257,392)	(1,396,363)		
May 2020	1,756,110	466,423	(3,782,751)	(1,004,699)	(5,239,611)	(1,391,641)		
Jun 2020	1,738,726	461,806	(3,776,376)	(1,003,005)	(5,221,830)	(1,386,918)		
Jul 2020	1,721,342	457,188	(3,767,964)	(1,000,771)	(5,204,049)	(1,382,195)		
Aug 2020	1,703,958	452,571	(3,736,509)	(992,417)	(5,186,268)	(1,377,473)		
Sep 2020	1,686,574	447,954	(3,710,813)	(985,592)	(5,168,487)	(1,372,750)		
Oct 2020	1,669,190	443,337	(3,662,653)	(972,801)	(5,150,706)	(1,368,027)		
Nov 2020	1,651,806	438,720	(3,804,349)	(1,010,435)	(5,132,925)	(1,363,305)		
Dec 2020	1,634,422	434,102	(2,713,204)	(720,627)	(6,041,411)	(1,604,599)		
Jan 2021	1,634,422	463,195	(2,706,639)	(767,061)	(6,041,411)	(1,712,136)		
Feb 2021	1,603,166	454,337	(2,657,706)	(753,194)	(6,009,239)	(1,703,018)		
Mar 2021	1,587,538	449,908	(2,651,557)	(751,451)	(5,993,153)	(1,698,459)		
Apr 2021	1,571,910	445,479	(2,617,325)	(741,750)	(5,977,067)	(1,693,901)		
May 2021	1,556,282	441,050	(2,586,708)	(733,073)	(5,960,981)	(1,689,342)		
Jun 2021	1,540,654	436,621	(2,582,568)	(731,900)	(5,944,895)	(1,684,783)		
Jul 2021	1,525,026	432,192	(2,577,317)	(730,412)	(5,928,809)	(1,680,224)		
Aug 2021	1,509,398	427,763	(2,581,541)	(731,609)	(5,912,723)	(1,675,666)		
Sep 2021 (estimated)	1,493,770	423,334	(2,585,764)	(732,806)	(5,896,637)	(1,671,107)		
Oct 2021 (estimated)	1,478,142	418,905	(2,589,988)	(734,003)	(5,880,551)	(1,666,548)		
Nov 2021 (estimated)	1,462,514	414,476	(2,594,212)	(735,200)	(5,864,465)	(1,661,989)		

DUKE ENERGY KENTUCKY

Pension	FERC 128 Total	FERC 128 Gas	FERC 182.3 Total	FERC 182.3 Gas	FERC 186 Total	FERC 186 Gas	FERC 228.3 Total	FERC 228.3 Gas
Dec 2021 (estimated)	1,446,886	410,047	(2,598,436)	(736,397)	(5,848,379)	(1,657,431)		
Jan 2022 (estimated)	1,432,901	406,084	(2,598,304)	(736,359)	(5,875,030)	(1,664,984)		
Feb 2022 (estimated)	1,418,916	402,121	(2,598,172)	(736,322)	(5,901,681)	(1,672,536)		
Mar 2022 (estimated)	1,404,931	398,157	(2,598,040)	(736,285)	(5,928,332)	(1,680,089)		
Apr 2022 (estimated)	1,390,946	394,194	(2,597,908)	(736,247)	(5,954,983)	(1,687,642)		
May 2022 (estimated)	1,376,961	390,231	(2,597,776)	(736,210)	(5,981,634)	(1,695,195)		
Jun 2022 (estimated)	1,362,976	386,267	(2,597,644)	(736,172)	(6,008,285)	(1,702,748)		
Jul 2022 (estimated)	1,348,991	382,304	(2,597,512)	(736,135)	(6,034,936)	(1,710,301)		
Aug 2022 (estimated)	1,335,006	378,341	(2,597,380)	(736,097)	(6,061,587)	(1,717,854)		
Sep 2022 (estimated)	1,321,021	374,377	(2,597,248)	(736,060)	(6,088,238)	(1,725,407)		
Oct 2022 (estimated)	1,307,036	370,414	(2,597,116)	(736,023)	(6,114,889)	(1,732,960)		
Nov 2022 (estimated)	1,293,051	366,451	(2,596,984)	(735,985)	(6,141,540)	(1,740,512)		
Dec 2022 (estimated)	1,279,066	362,487	(2,596,852)	(735,948)	(6,168,191)	(1,748,065)		

Duke Energy Kentucky
Case No. 2021-00190
Attorney General's Second Set Data Requests
Date Received: August 4, 2021

AG-DR-02-028

REQUEST:

Refer to the response to AG 1-15 (k) Attachment related to the $13.792 million investment in account 27800 for the "STA 872 – Oakland Valve House" project.

a. Provide the capital investment amount added to rate base in this case related to the STA 872 – Oakland Valve House. Provide plant additions by FERC and Company plant account number and in total and by month.

b. Provide a calculation of the revenue requirement included in the test year for the STA 872 – Oakland Valve House, providing all components of the return on and of investment costs. Provide in electronic format with all formulas intact.

c. Provide the depreciation rate(s) applied in the test year for the STA 872 – Oakland Valve House and provide the source of those rates.

d. Provide the probable retirement date for this project and all supporting documentation.

e. Provide a detailed explanation of the STA 872 – Oakland Valve House, including what it is, where it is, who it serves, and how it is recorded in the Company's fixed asset accounting records, including whether it is recorded as a separate asset in one or more subaccounts.

RESPONSE:

a. Please see AG-DR-02-028(a) Attachment.

b. The Company does not calculate a revenue requirement separately for each project. However, please see AG-DR-02-028(b) Attachment for an estimated revenue requirement.

c. The assets are in 2780 – System Meas & Reg Station and the rate for that asset group is 2.04%. This rate is from the depreciation study approved in 2019 as part of Case No. 2018-00261 and is the same rate proposed in this case.

d. The Company has not established a specific probable retirement date. A good estimation of the expected life would be the average service life which is established in a depreciation study. The average service life for assets classified as "2780 – System Meas & Reg Station" is 52 years.

e. This project constructed a major regulator facility for a distribution system in the Covington Kentucky area. The equipment serves the entire distribution system and was not installed for one specific customer. The construction consisted of replacing antiquated underground system regulator station equipment with above ground equipment on skids. Locating the equipment above ground rather than underground prevents corrosion of the equipment. It is recorded to account 278 – Meas & Reg Station, as a single asset.

PERSON RESPONSIBLE: David G. Raiford – a., c., d., and e.
Jay P. Brown – b.

a. Provide the capital investment amount added to rate base in this case related to STA 872 - Oakland Valve House. Provide plant additions by FERC and Company plant account number and in total and by month.

Project Number: MX2335804

Utility Account	Month	STA 872 - OAKLAND VALVE HOUSE
27800 - System Meas & Reg Station	Jul-19	9,869,433.30
27800 - System Meas & Reg Station	Aug-19	3,016,187.13
27800 - System Meas & Reg Station	Sep-19	(301,564.16)
27800 - System Meas & Reg Station	Oct-19	618,297.04
27800 - System Meas & Reg Station	Nov-19	47,816.68
27800 - System Meas & Reg Station	Dec-19	3,132.71
27800 - System Meas & Reg Station	Jan-20	527,689.61
27800 - System Meas & Reg Station	Feb-20	9,691.77
27800 - System Meas & Reg Station	Mar-20	88.36
27800 - System Meas & Reg Station	May-20	824.68
27800 - System Meas & Reg Station Total		**13,791,597.12**

Duke Energy Kentucky
Estimated Revenue Requirement
STA 872 - OAKLAND VALVE HOUSE

Line	Description	Test Period
1	Gross Plant[(a)]	$13,791,597
2	Accumulated Depreciation	($692,391)
3	Net Plant in Service	$13,099,206
4	Accum Def Income Taxes on Plant [(b)]	($358,120)
5	Rate Base	**$12,741,086**
6	Return on Rate Base (Pre-Tax %) [(c)]	8.81%
7	Return on Rate Base (Pre-Tax)	$1,122,490
8	Depreciation Expense	281,349
9	Annualized Property Tax Expense [(d)]	99,554
10	Estimated Revenue Requirement (Lines 7 - 9)	$1,503,393

Assumptions:

[(a)] 13 month average of cumulative gross plant

[(b)] Assumes 49.02 year book life; 20 year MACRS

[(c)] Weighted-Average Cost of Capital from Schedule A in Case No. 2021-00190, with ROE at 10.3%, grossed up for 21% FIT rate.

[(d)] Assumes 0.76% of net plant; derived from test year property taxes divided by test year net plant.

Duke Energy Kentucky
Estimated Revenue Requirement
STA 872 - OAKLAND VALVE HOUSE

Line	Description	Test Period												
		Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
1	Balance of Gross Plant by Account													
	27800 - System Meas & Reg Station	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597
2	Cumulative Gross Plant[(a)]	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597
3	13 Month Average (Average of Ln 2):	$13,791,597												

[(a)] Project was placed in service in 2019.

Duke Energy Kentucky
Estimated Revenue Requirement
STA 872 - OAKLAND VALVE HOUSE

	Property, Plant and Equipment (Capital)									
Project	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
STA 872 - OAKLAND VALVE HOUSE	$13,253,303	$ 538,294	$0	$0	$0	$0	$0	$0	$0	$0
Cumulative Gross Plant[a]	13,253,303	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597	13,791,597
Depreciation Expense	135,184	275,858	281,349	281,349	281,349	281,349	281,349	281,349	281,349	281,349
Accumulated Depreciation	($135,184)	($411,042)	($692,391)	($973,740)	($1,255,089)	($1,536,438)	($1,817,787)	($2,099,136)	($2,380,485)	($2,661,834)
Accumulated Deferred Income Tax	($75,981)	($223,209)	($358,120)	($478,502)	($585,405)	($679,872)	($762,805)	($835,103)	905,318	975,437

Book Life	Tax Life
49.02	20.00

			Tax Deprecation on										
	20 Yr MACRS	**Cap Additions**	**2019 Spend**	**2020 Spend**	**2021 Spend**	**2022 Spend**	**2023 Spend**	**Total Tax Depr**	**Book Depreciation**	**Gross Plant**	**Accumulated Depreciation**	**Deferred Tax**	**ADIT**
2019	3.75%	$13,253,303	$496,999					$496,999	$135,184	$13,253,303	$135,184	$75,981	$75,981
2020	7.22%	538,294	956,756	$ 20,186.04				976,942	275,858	13,791,597	411,042	147,228	223,209
2021	6.68%	-	884,923	38,859	$0			923,782	281,349	13,791,597	692,391	134,911	358,120
2022	6.18%	-	818,657	35,942	-	$0		854,598	281,349	13,791,597	973,740	120,382	478,502
2023	5.71%	-	757,161	33,250	-	-	$0	790,412	281,349	13,791,597	1,255,089	106,903	585,405
2024	5.29%	-	700,437	30,753	-	-	-	731,190	281,349	13,791,597	1,536,438	94,467	679,872
2025	4.89%	-	647,821	28,449	-	-	-	676,270	281,349	13,791,597	1,817,787	82,933	762,805
2026	4.52%	-	599,314	26,312	-	-	-	625,626	281,349	13,791,597	2,099,136	72,298	835,103
2027	4.46%	-	591,362	24,342	-	-	-	615,704	281,349	13,791,597	2,380,485	70,215	905,318
2028	4.46%	-	591,230	24,019	-	-	-	615,249	281,349	13,791,597	2,661,834	70,119	975,437
2029	4.46%		591,362	24,013	-	-	-	615,376	281,349	13,791,597	2,943,183	70,146	1,045,583
2030	4.46%		591,230	24,019	-	-	-	615,249	281,349	13,791,597	3,224,532	70,119	1,115,702
2031	4.46%		591,362	24,013	-	-	-	615,376	281,349	13,791,597	3,505,881	70,146	1,185,848
2032	4.46%		591,230	24,019	-	-	-	615,249	281,349	13,791,597	3,787,230	70,119	1,255,967
2033	4.46%		591,362	24,013	-	-	-	615,376	281,349	13,791,597	4,068,579	70,146	1,326,113
2034	4.46%		591,230	24,019	-	-	-	615,249	281,349	13,791,597	4,349,928	70,119	1,396,232
2035	4.46%		591,362	24,013	-	-	-	615,376	281,349	13,791,597	4,631,277	70,146	1,466,378
2036	4.46%		591,230	24,019	-	-	-	615,249	281,349	13,791,597	4,912,626	70,119	1,536,497
2037	4.46%		591,362	24,013	-	-	-	615,376	281,349	13,791,597	5,193,975	70,146	1,606,643
2038	4.46%		591,230	24,019	-	-	-	615,249	281,349	13,791,597	5,475,324	70,119	1,676,762
2039	2.23%		295,681	24,013	-	-	-	319,694	281,349	13,791,597	5,756,673	8,053	1,684,815
2040			-	12,009	-	-	-	12,009	281,349	13,791,597	6,038,022	(56,561)	1,628,254
2041			-	-	-	-	-	-	281,349	13,791,597	6,319,371	(59,083)	1,569,171
2042									281,349	13,791,597	6,600,720	(59,083)	1,510,088
2043									281,349	13,791,597	6,882,069	(59,083)	1,451,005
2044									281,349	13,791,597	7,163,418	(59,083)	1,391,922
2045									281,349	13,791,597	7,444,767	(59,083)	1,332,839
2046									281,349	13,791,597	7,726,116	(59,083)	1,273,756
2047									281,349	13,791,597	8,007,465	(59,083)	1,214,673
2048									281,349	13,791,597	8,288,814	(59,083)	1,155,590
2049									281,349	13,791,597	8,570,163	(59,083)	1,096,507
2050									281,349	13,791,597	8,851,512	(59,083)	1,037,424
2051									281,349	13,791,597	9,132,861	(59,083)	978,341
2052									281,349	13,791,597	9,414,210	(59,083)	919,258
2053									281,349	13,791,597	9,695,559	(59,083)	860,175
2054									281,349	13,791,597	9,976,908	(59,083)	801,092
2055									281,349	13,791,597	10,258,257	(59,083)	742,009
2056									281,349	13,791,597	10,539,606	(59,083)	682,926
2057									281,349	13,791,597	10,820,955	(59,083)	623,843
2058									281,349	13,791,597	11,102,304	(59,083)	564,760
2059									281,349	13,791,597	11,383,653	(59,083)	505,677
2060									281,349	13,791,597	11,665,002	(59,083)	446,594
2061									281,349	13,791,597	11,946,351	(59,083)	387,511
2062									281,349	13,791,597	12,227,700	(59,083)	328,428
2063									281,349	13,791,597	12,509,049	(59,094)	269,334
2064									281,349	13,791,597	12,790,398	(59,083)	210,251
2065									281,349	13,791,597	13,071,747	(59,083)	151,168
2066									281,349	13,791,597	13,353,096	(59,083)	92,085
2067									281,349	13,791,597	13,634,445	(59,083)	33,002
2068									157,152	13,791,597	13,791,597	(33,002)	-
	100.00%	$13,791,597	$13,253,303	$538,294	$0	$0	$0	$13,791,597	$13,791,597			-	

AG-DR-02-029

REQUEST:

Refer to STAFF-DR-02-024(a) Attachment 3, page 94 of 145, and the following excerpt from the Order in Florida Public Service Commission Docket No. 20200139-WS:

> The only cost of equity model analysis that supports a 10.75 percent ROE is UIF witness D'Ascendis' Predictive Risk Premium Model (PRPM) with an average result of 11.66 percent. However, the record showed that the PRPM is based on the GARCH model, which used Eviews statistical software to derive a predictive equity risk premium, which is added to a projected risk-free rate. This method is akin to a black box calculation where the inputs were entered and a result was produced using statistical software. Witness D'Ascendis and his colleagues developed the PRPM method and admitted that it is used primarily by himself and other colleagues familiar with the methodology. The record failed to support that witness D'Ascendis' PRPM methodology is widely accepted by other jurisdictions as a method to estimate the equity risk premium. Therefore, we find that the cost of equity models using the PRPM shall be discounted in this case.

Provide responses to the following:

a. Does Mr. D'Ascendis still admit that the PRPM method "is used primarily by himself and other colleagues familiar with the methodology." If not, explain why not.

b. Aside from Mr. D'Ascendis, provide names of the other colleagues who have presented the PRPM in proceedings to estimate the risk premium rate of return for regulated utilities. Include in the response the case number, regulatory jurisdiction, and year.

c. Provide any other proceedings (other than Duke Kentucky affiliate state commissions) of which Mr. D'Ascendis is aware in which regulatory commissions have accepted or rejected the PRPM. Include in the response the case number, year and a copy of the Commission's Order.

d. Provide evidence that the PRPM method is widely used and accepted by investors to estimate their required return on equity for regulated utilities.

RESPONSE:

a. Mr. D'Ascendis does not recall "admitting" that the PRPM is primarily used by himself and other colleagues familiar with the model. As discussed in Mr. D'Ascendis' Direct Testimony,[1] the PRPM is based on the research of Dr. Robert F. Engle, dating back to the early 1980s. Dr. Engle discovered that the volatility of market prices, returns, and risk premiums clusters over time, making prices, returns, and risk premiums highly predictable. In 2003, he shared the Nobel Prize in Economics for this work, characterized as "methods of analyzing economic time series with time-varying volatility ("ARCH").[2] Dr. Engle[3] noted that relative to volatility, "the standard tools have become the ARCH/GARCH[4] models." (Please see AG-DR-02-029(a) Attachment 1.) Hence, the methodology is not exclusively used by Mr. D'Ascendis.

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[1] D'Ascendis Direct Testimony, at 20-21.
[2] www.nobelprize.org.
[3] Robert Engle, *GARCH 101: The Use of ARCH/GARCH Models in Applied Econometrics*, Journal of Economic Perspectives, Volume 15, No. 4, Fall 2001, at 157-168.
[4] Autoregressive Conditional Heteroskedasticity/Generalized Autoregressive Conditional Heteroskedasticity.

In addition, the GARCH methodology has been well tested by academia since Engle's, *et al*. research was originally published in 1982, 39 years ago. Mr. D'Ascendis uses the well-established GARCH methodology to estimate the PRPM model using a standard commercial and relatively inexpensive statistical package, Eviews,©[5] to develop a means by which to estimate a predicted ERP which, when added to a bond yield, results in a cost of common equity.

Also, the PRPM is in the public domain, having been published six times in academically peer-reviewed journals: Journal of Economics and Business (June 2011 and April 2015)(Please see AG-DR-02-029(a) Attachments 2 and 3),[6] *The* Journal of Regulatory Economics (December 2011)(Please see AG-DR-02-029(a) Attachment 4),[7] The Electricity Journal (May 2013 and March 2020)(Please see AG-DR-02-029(a) Attachments 5 and 6,[8] and Energy Policy (April 2019)(Please see AG-DR-02-029(a) Attachment 7).[9] Notably, none of these articles have been rebutted in the academic literature.

b. While Mr. D'Ascendis has not performed an exhaustive review of all past regulatory proposals of the PRPM, he understands that Pauline M. Ahern, Frank J.

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[5] In addition to Eviews,® the GARCH methodology can be applied and the PRPM derived using other standard statistical software packages such as SAS, RATS, S-Plus and JMulti, which are not cost-prohibitive. The software that I used in this proceeding, Eviews,® currently costs $600 - $700 for a single user commercial license. In addition, JMulti is a free downloadable software with GARCH estimation applications.

[6] Eugene A. Pilotte and Richard A. Michelfelder, *Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing*, Journal of Economics and Business, June 2011, 582-604. and Richard A. Michelfelder, *Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital*, Journal of Economics and Business, April 2015, 37-50.

[7] Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, *New Approach to Estimating the Equity Risk Premium for Public Utilities*, The Journal of Regulatory Economics, December 2011, at 40:261-278.

[8] Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, *Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity*, The Electricity Journal, April 2013, at 84-89; and Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, *Decoupling, Risk Impacts and the Cost of Capital*, The Electricity Journal, January 2020.

[9] Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, *Decoupling Impact and Public Utility Conservation Investment*, Energy Policy, April 2019, 311-319.

Hanley, Robert B. Hevert, and John Perkins have similarly included PRPM analyses in cases for which they provided testimony.

c. To Mr. D'Ascendis' knowledge, the only commissions to address the PRPM are the ones provided in response to STAFF-DR-02-024.

d. Please refer to Mr. D'Ascendis' response to part (a), above. Additionally, the PRPM was presented to a number of utility industry/regulatory/academic groups including the following: The Edison Electric Institute Cost of Capital Working Group; The NARUC Staff Subcommittee on Accounting and Finance; The National Association of Electric Companies Finance/Accounting/Taxation and Rates and Regulations Committees; the NARUC Electric Committee; The Wall Street Utility Group; the Indiana Utility Regulatory Commission Cost of Capital Task Force; the Financial Research Institute of the University of Missouri Hot Topic Hotline Webinar; and the Center for Research and Regulated Industries Annual Eastern Conference on two occasions.

PERSON RESPONSIBLE: Dylan W. D'Ascendis

Journal of Economic Perspectives—Volume 15, Number 4—Fall 2001—Pages 157–168

GARCH 101: The Use of ARCH/GARCH Models in Applied Econometrics

Robert Engle

The great workhorse of applied econometrics is the least squares model. This is a natural choice, because applied econometricians are typically called upon to determine how much one variable will change in response to a change in some other variable. Increasingly however, econometricians are being asked to forecast and analyze the size of the errors of the model. In this case, the questions are about volatility, and the standard tools have become the ARCH/GARCH models.

The basic version of the least squares model assumes that the expected value of all error terms, when squared, is the same at any given point. This assumption is called homoskedasticity, and it is this assumption that is the focus of ARCH/GARCH models. Data in which the variances of the error terms are not equal, in which the error terms may reasonably be expected to be larger for some points or ranges of the data than for others, are said to suffer from heteroskedasticity. The standard warning is that in the presence of heteroskedasticity, the regression coefficients for an ordinary least squares regression are still unbiased, but the standard errors and confidence intervals estimated by conventional procedures will be too narrow, giving a false sense of precision. Instead of considering this as a problem to be corrected, ARCH and GARCH models treat heteroskedasticity as a variance to be modeled. As a result, not only are the deficiencies of least squares corrected, but a prediction is computed for the variance of each error term. This prediction turns out often to be of interest, particularly in applications in finance.

The warnings about heteroskedasticity have usually been applied only to cross-section models, not to time series models. For example, if one looked at the

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cross-section relationship between income and consumption in household data, one might expect to find that the consumption of low-income households is more closely tied to income than that of high-income households, because the dollars of savings or deficit by poor households are likely to be much smaller in absolute value than high income households. In a cross-section regression of household consumption on income, the error terms seem likely to be systematically larger in absolute value for high-income than for low-income households, and the assumption of homoskedasticity seems implausible. In contrast, if one looked at an aggregate time series consumption function, comparing national income to consumption, it seems more plausible to assume that the variance of the error terms doesn't change much over time.

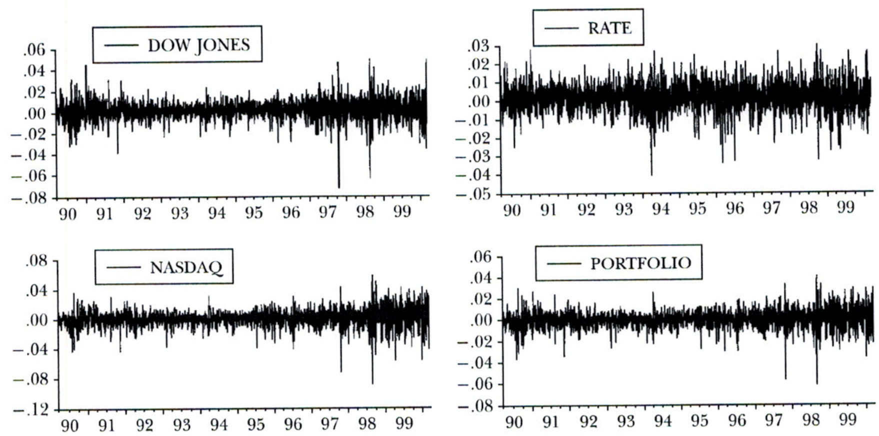
A recent development in estimation of standard errors, known as "robust standard errors," has also reduced the concern over heteroskedasticity. If the sample size is large, then robust standard errors give quite a good estimate of standard errors even with heteroskedasticity. If the sample is small, the need for a heteroskedasticity correction that does not affect the coefficients, and only asymptotically corrects the standard errors, can be debated.

However, sometimes the natural question facing the applied econometrician is the accuracy of the predictions of the model. In this case, the key issue is the variance of the error terms and what makes them large. This question often arises in financial applications where the dependent variable is the return on an asset or portfolio and the variance of the return represents the risk level of those returns. These are time series applications, but it is nonetheless likely that heteroskedasticity is an issue. Even a cursory look at financial data suggests that some time periods are riskier than others; that is, the expected value of the magnitude of error terms at some times is greater than at others. Moreover, these risky times are not scattered randomly across quarterly or annual data. Instead, there is a degree of autocorrelation in the riskiness of financial returns. Financial analysts, looking at plots of daily returns such as in Figure 1, notice that the amplitude of the returns varies over time and describe this as "volatility clustering." The ARCH and GARCH models, which stand for autoregressive conditional heteroskedasticity and *generalized* autoregressive conditional heteroskedasticity, are designed to deal with just this set of issues. They have become widespread tools for dealing with time series heteroskedastic models. The goal of such models is to provide a volatility measure—like a standard deviation—that can be used in financial decisions concerning risk analysis, portfolio selection and derivative pricing.

ARCH/GARCH Models

Because this paper will focus on financial applications, we will use financial notation. Let the dependent variable be labeled r_t, which could be the return on an asset or portfolio. The mean value m and the variance h will be defined relative to a past information set. Then, the return r in the present will be equal to the mean

Figure 1
Nasdaq, Dow Jones and Bond Returns



value of r (that is, the expected value of r based on past information) plus the standard deviation of r (that is, the square root of the variance) times the error term for the present period.

The econometric challenge is to specify how the information is used to forecast the mean and variance of the return, conditional on the past information. While many specifications have been considered for the mean return and have been used in efforts to forecast future returns, virtually no methods were available for the variance before the introduction of ARCH models. The primary descriptive tool was the rolling standard deviation. This is the standard deviation calculated using a fixed number of the most recent observations. For example, this could be calculated every day using the most recent month (22 business days) of data. It is convenient to think of this formulation as the first ARCH model; it assumes that the variance of tomorrow's return is an equally weighted average of the squared residuals from the last 22 days. The assumption of equal weights seems unattractive, as one would think that the more recent events would be more relevant and therefore should have higher weights. Furthermore the assumption of zero weights for observations more than one month old is also unattractive. The ARCH model proposed by Engle (1982) let these weights be parameters to be estimated. Thus, the model allowed the data to determine the best weights to use in forecasting the variance.

A useful generalization of this model is the GARCH parameterization introduced by Bollerslev (1986). This model is also a weighted average of past squared residuals, but it has declining weights that never go completely to zero. It gives parsimonious models that are easy to estimate and, even in its simplest form, has proven surprisingly successful in predicting conditional variances. The most widely used GARCH specification asserts that the best predictor of the variance in the next period is a weighted average of the long-run average variance, the variance predicted for this period, and the new information in this period that is captured by the most recent squared residual. Such an updating rule is a simple description of adaptive or learning behavior and can be thought of as Bayesian updating.

Consider the trader who knows that the long-run average daily standard deviation of the Standard and Poor's 500 is 1 percent, that the forecast he made yesterday was 2 percent and the unexpected return observed today is 3 percent. Obviously, this is a high volatility period, and today is especially volatile, which suggests that the forecast for tomorrow could be even higher. However, the fact that the long-term average is only 1 percent might lead the forecaster to lower the forecast. The best strategy depends upon the dependence between days. If these three numbers are each squared and weighted equally, then the new forecast would be $2.16 = \sqrt{(1 + 4 + 9)/3}$. However, rather than weighting these equally, it is generally found for daily data that weights such as those in the empirical example of (.02, .9, .08) are much more accurate. Hence the forecast is $2.08 = \sqrt{.02*1 + .9*4 + .08*9}$.

To be precise, we can use h_t to define the variance of the residuals of a regression $r_t = m_t + \sqrt{h_t}\varepsilon_t$. In this definition, the variance of ε is one. The GARCH model for variance looks like this:

$$h_{t+1} = \omega + \alpha(r_t - m_t)^2 + \beta h_t = \omega + \alpha h_t \varepsilon_t^2 + \beta h_t.$$

The econometrician must estimate the constants ω, α, β; updating simply requires knowing the previous forecast h and residual. The weights are $(1 - \alpha - \beta, \beta, \alpha)$, and the long-run average variance is $\sqrt{\omega/(1 - \alpha - \beta)}$. It should be noted that this only works if $\alpha + \beta < 1$, and it only really makes sense if the weights are positive, requiring $\alpha > 0$, $\beta > 0$, $\omega > 0$.

The GARCH model that has been described is typically called the GARCH(1,1) model. The (1,1) in parentheses is a standard notation in which the first number refers to how many autoregressive lags, or ARCH terms, appear in the equation, while the second number refers to how many moving average lags are specified, which here is often called the number of GARCH terms. Sometimes models with more than one lag are needed to find good variance forecasts.

Although this model is directly set up to forecast for just one period, it turns out that based on the one-period forecast, a two-period forecast can be made. Ultimately, by repeating this step, long-horizon forecasts can be constructed. For the GARCH(1,1), the two-step forecast is a little closer to the long-run average variance than is the one-step forecast, and, ultimately, the distant-horizon forecast is the same for all time periods as long as $\alpha + \beta < 1$. This is just the unconditional variance. Thus, the GARCH models are mean reverting and conditionally heteroskedastic, but have a constant unconditional variance.

I turn now to the question of how the econometrician can possibly estimate an equation like the GARCH(1,1) when the only variable on which there are data is r_t. The simple answer is to use maximum likelihood by substituting h_t for σ^2 in the normal likelihood and then maximizing with respect to the parameters. An even simpler answer is to use software such as EViews, SAS, GAUSS, TSP, Matlab, RATS and many others where there exist already packaged programs to do this.

But the process is not really mysterious. For any set of parameters ω, α, β and a starting estimate for the variance of the first observation, which is often taken to be the observed variance of the residuals, it is easy to calculate the variance forecast for the second observation. The GARCH updating formula takes the weighted average of the unconditional variance, the squared residual for the first observation and the starting variance and estimates the variance of the second observation. This is input into the forecast of the third variance, and so forth. Eventually, an entire time series of variance forecasts is constructed. Ideally, this series is large when the residuals are large and small when they are small. The likelihood function provides a systematic way to adjust the parameters ω, α, β to give the best fit.

Of course, it is entirely possible that the true variance process is different from the one specified by the econometrician. In order to detect this, a variety of diagnostic tests are available. The simplest is to construct the series of $\{\varepsilon_t\}$, which are supposed to have constant mean and variance if the model is correctly specified. Various tests such as tests for autocorrelation in the squares are able to detect model failures. Often a "Ljung box test" with 15 lagged autocorrelations is used.

A Value-at-Risk Example

Applications of the ARCH/GARCH approach are widespread in situations where the volatility of returns is a central issue. Many banks and other financial institutions use the concept of "value at risk" as a way to measure the risks faced by their portfolios. The 1 percent value at risk is defined as the number of dollars that one can be 99 percent certain exceeds any losses for the next day. Statisticians call this a 1 percent quantile, because 1 percent of the outcomes are worse and 99 percent are better. Let's use the GARCH(1,1) tools to estimate the 1 percent value at risk of a $1,000,000 portfolio on March 23, 2000. This portfolio consists of 50 percent Nasdaq, 30 percent Dow Jones and 20 percent long bonds. The long bond is a ten-year constant maturity Treasury bond.[1] This date is chosen to be just before the big market slide at the end of March and April. It is a time of high volatility and great anxiety.

First, we construct the hypothetical historical portfolio. (All calculations in this example were done with the EViews software program.) Figure 1 shows the pattern of returns of the Nasdaq, Dow Jones, bonds and the composite portfolio leading up to the terminal date. Each of these series appears to show the signs of ARCH effects in that the amplitude of the returns varies over time. In the case of the equities, it is clear that this has increased substantially in the latter part of the sample period. Visually, Nasdaq is even more extreme. In Table 1, we present some illustrative

[1] The portfolio has constant proportions of wealth in each asset that would entail some rebalancing over time.

Table 1
Portfolio Data

	NASDAQ	*Dow Jones*	*Rate*	*Portfolio*
Mean	0.0009	0.0005	0.0001	0.0007
Std. Dev.	0.0115	0.0090	0.0073	0.0083
Skewness	−0.5310	−0.3593	−0.2031	−0.4738
Kurtosis	7.4936	8.3288	4.9579	7.0026

Sample: March 23, 1990 to March 23, 2000.

statistics for each of these three investments separately and for the portfolio as a whole in the final column. From the daily standard deviation, we see that the Nasdaq is the most volatile and interest rates the least volatile of the assets. The portfolio is less volatile than either of the equity series even though it is 80 percent equity—yet another illustration of the benefits of diversification. All the assets show evidence of fat tails, since the kurtosis exceeds 3, which is the normal value, and evidence of negative skewness, which means that the left tail is particularly extreme.

The portfolio shows substantial evidence of ARCH effects as judged by the autocorrelations of the squared residuals in Table 2. The first order autocorrelation is .210, and they gradually decline to .083 after 15 lags. These autocorrelations are not large, but they are very significant. They are also all positive, which is uncommon in most economic time series and yet is an implication of the GARCH(1,1) model. Standard software allows a test of the hypothesis that there is no autocorrelation (and hence no ARCH). The test *p*-values shown in the last column are all zero to four places, resoundingly rejecting the "no ARCH" hypothesis.

Then we forecast the standard deviation of the portfolio and its 1 percent quantile. We carry out this calculation over several different time frames: the entire ten years of the sample up to March 23, 2000; the year before March 23, 2000; and from January 1, 2000, to March 23, 2000.

Consider first the quantiles of the historical portfolio at these three different time horizons. To do this calculation, one simply sorts the returns and finds the 1 percent worst case. Over the full ten-year sample, the 1 percent quantile times $1,000,000 produces a value at risk of $22,477. Over the last year, the calculation produces a value at risk of $24,653—somewhat higher, but not enormously so. However, if the 1 percent quantile is calculated based on the data from January 1, 2000, to March 23, 2000, the value at risk is $35,159. Thus, the level of risk apparently has increased dramatically over the last quarter of the sample. Each of these numbers is the appropriate value at risk if the next day is equally likely to be the same as the days in the given sample period. This assumption is more likely to be true for the shorter period than for the long one.

The basic GARCH(1,1) results are given in Table 3. Under this table it lists the dependent variable, PORT, and the sample period, indicates that it took the algorithm 16 iterations to maximize the likelihood function and computed stan-

Table 2
Autocorrelations of Squared Portfolio Returns

	AC	*Q-Stat*	*Prob*
1	0.210	115.07	0.000
2	0.183	202.64	0.000
3	0.116	237.59	0.000
4	0.082	255.13	0.000
5	0.122	294.11	0.000
6	0.163	363.85	0.000
7	0.090	384.95	0.000
8	0.099	410.77	0.000
9	0.081	427.88	0.000
10	0.081	445.03	0.000
11	0.069	457.68	0.000
12	0.080	474.29	0.000
13	0.076	489.42	0.000
14	0.074	503.99	0.000
15	0.083	521.98	0.000

Sample: March 23, 1990 to March 23, 2000.

Table 3
GARCH(1,1)

	Variance Equation			
Variable	*Coef*	*St. Err*	*Z-Stat*	*P-Value*
C	1.40E-06	4.48E-07	3.1210	0.0018
ARCH(1)	0.0772	0.0179	4.3046	0.0000
GARCH(1)	0.9046	0.0196	46.1474	0.0000

Notes: Dependent Variable: PORT.
Sample (adjusted): March 23, 1990 to March 23, 2000.
Convergence achieved after 16 iterations.
Bollerslev-Woodridge robust standard errors and covariance.

dard errors using the robust method of Bollerslev-Wooldridge. The three coefficients in the variance equation are listed as C, the intercept; ARCH(1), the first lag of the squared return; and GARCH(1), the first lag of the conditional variance. Notice that the coefficients sum up to a number less than one, which is required to have a mean reverting variance process. Since the sum is very close to one, this process only mean reverts slowly. Standard errors, *Z*-statistics (which are the ratio of coefficients and standard errors) and *p*-values complete the table.

The standardized residuals are examined for autocorrelation in Table 4. Clearly, the autocorrelation is dramatically reduced from that observed in the portfolio returns themselves. Applying the same test for autocorrelation, we now

Table 4
Autocorrelations of Squared Standardized Residuals

	AC	*Q-Stat*	*Prob*
1	0.005	0.0589	0.808
2	0.039	4.0240	0.134
3	−0.011	4.3367	0.227
4	−0.017	5.0981	0.277
5	0.002	5.1046	0.403
6	0.009	5.3228	0.503
7	−0.015	5.8836	0.553
8	−0.013	6.3272	0.611
9	−0.024	7.8169	0.553
10	−0.006	7.9043	0.638
11	−0.023	9.3163	0.593
12	−0.013	9.7897	0.634
13	−0.003	9.8110	0.709
14	0.009	10.038	0.759
15	−0.012	10.444	0.791

find the *p*-values are about 0.5 or more, indicating that we can accept the hypothesis of "no residual ARCH."

The forecast standard deviation for the next day is 0.0146, which is almost double the average standard deviation of 0.0083 presented in the last column of Table 1. If the residuals were normally distributed, then this would be multiplied by 2.327, because 1 percent of a normal random variable lies 2.327 standard deviations below the mean. The estimated normal value at risk = $33,977. As it turns out, the standardized residuals, which are the estimated values of $\{\varepsilon_t\}$, are not very close to a normal distribution. They have a 1 percent quantile of 2.844, which reflects the fat tails of the asset price distribution. Based on the actual distribution, the estimated 1 percent value at risk is $39,996. Notice how much this value at risk has risen to reflect the increased risk in 2000.

Finally, the value at risk can be computed based solely on estimation of the quantile of the forecast distribution. This has recently been proposed by Engle and Manganelli (2001), adapting the quantile regression methods of Koenker and Basset (1978) and Koenker and Hallock in this symposium. Application of their method to this data set delivers a value at risk = $38,228.

What actually did happen on March 24, 2000, and subsequently? The portfolio lost more than $1000 on March 24 and more than $3000 on March 27. The biggest hit was $67,000 on April 14. We all know that Nasdaq declined substantially over the next year. The Dow Jones average was much less affected, and bond prices increased as the Federal Reserve lowered interest rates. Figure 2 plots the value at risk estimated each day using this methodology within the sample period and the losses that occurred the next day. There are about 1 percent of times the value at risk is exceeded, as is expected, since this is in-sample. Figure 3 plots the same graph for the next year and a quarter, during

Figure 2
Value at Risk and Portfolio Losses In-Sample

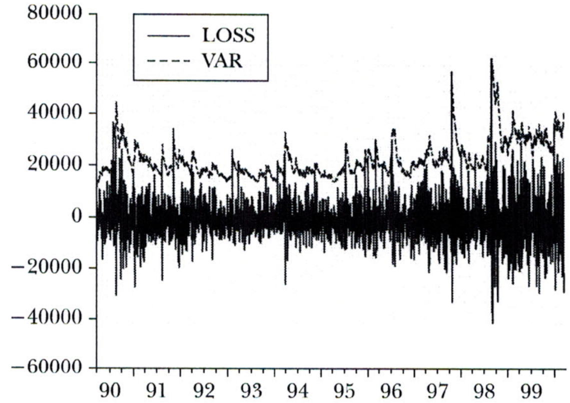
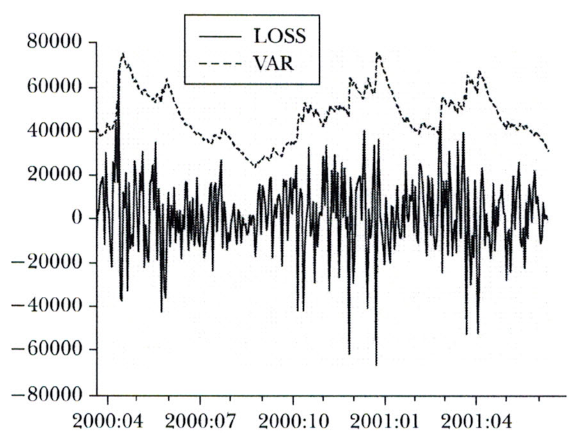


Figure 3
Value at Risk and Portfolio Losses Out of Sample



which the equity market tanks and the bond yields fall. The parameters are not reestimated, but the formula is simply updated each day. The computed value at risk rises substantially from the $40,000 initial figure as the volatility rises in April 2000. Then the losses decline, so that the value at risk is well above the realized losses. Toward the end of the period, the losses approach the value at risk again, but at a lower level. In this year and a quarter, the value at risk is exceeded only once; thus, this is actually a slightly conservative estimate of the risk. It is not easy to determine whether a particular value-at-risk number is correct, although statistical tests can be formulated for this in the same way they are formulated for volatilities. For example, Engle and Manganelli (2001) present a "dynamic quantile test."

Extensions and Modifications of GARCH

The GARCH(1,1) is the simplest and most robust of the family of volatility models. However, the model can be extended and modified in many ways. I will briefly mention three modifications, although the number of volatility models that can be found in the literature is now quite extraordinary.

The GARCH(1,1) model can be generalized to a GARCH(p,q) model—that is, a model with additional lag terms. Such higher-order models are often useful when a long span of data is used, like several decades of daily data or a year of hourly data. With additional lags, such models allow both fast and slow decay of information. A particular specification of the GARCH(2,2) by Engle and Lee (1999), sometimes called the "component model," is a useful starting point to this approach.

ARCH/GARCH models thus far have ignored information on the direction of returns; only the magnitude matters. However, there is very convincing evidence that the direction does affect volatility. Particularly for broad-based equity indices and bond market indices, it appears that market declines forecast higher volatility than comparable market increases do. There is now a variety of asymmetric GARCH models, including the EGARCH model of Nelson (1991), the TARCH model—threshold ARCH—attributed to Rabemananjara and Zakoian (1993) and Glosten, Jaganathan and Runkle (1993), and a collection and comparison by Engle and Ng (1993).

The goal of volatility analysis must ultimately be to explain the causes of volatility. While time series structure is valuable for forecasting, it does not satisfy our need to explain volatility. The estimation strategy introduced for ARCH/GARCH models can be directly applied if there are predetermined or exogenous variables. Thus, we can think of the estimation problem for the variance just as we do for the mean. We can carry out specification searches and hypothesis tests to find the best formulation. Thus far, attempts to find the ultimate cause of volatility are not very satisfactory. Obviously, volatility is a response to news, which must be a surprise. However, the timing of the news may not be a surprise and gives rise to predictable components of volatility, such as economic announcements. It is also possible to see how the amplitude of news events is influenced by other news events. For example, the amplitude of return movements on the United States stock market may respond to the volatility observed earlier in the day in Asian markets as well as to the volatility observed in the United States on the previous day. Engle, Ito and Lin (1990) call these "heat wave" and "meteor shower" effects.

A similar issue arises when examining several assets in the same market. Does the volatility of one influence the volatility of another? In particular, the volatility of an individual stock is clearly influenced by the volatility of the market as a whole. This is a natural implication of the capital asset pricing model. It also appears that there is time variation in idiosyncratic volatility (for example, Engle, Ng and Rothschild, 1992).

This discussion opens the door to multivariate modeling where not only the volatilities but also the correlations are to be investigated. There are now a large number of multivariate ARCH models to choose from. These turn out often to be difficult to estimate and to have large numbers of parameters. Research is continuing to examine new classes of multivariate models that are more convenient for fitting large covariance matrices. This is relevant for systems of equations such as vector autoregressions and for portfolio problems where possibly thousands of assets are to be analyzed.

Conclusion

ARCH and GARCH models have been applied to a wide range of time series analyses, but applications in finance have been particularly successful and have been the focus of this introduction. Financial decisions are generally based upon the tradeoff between risk and return; the econometric analysis of risk is therefore an integral part of asset pricing, portfolio optimization, option pricing and risk management. This paper has presented an example of risk measurement that could be the input to a variety of economic decisions. The analysis of ARCH and GARCH models and their many extensions provides a statistical stage on which many theories of asset pricing and portfolio analysis can be exhibited and tested.

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Treasury Bond risk and return, the implications for the hedging of consumption and lessons for asset pricing

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ABSTRACT

All consumption-based models of asset pricing imply that the relation between the conditional mean and conditional volatility of *any* asset reflects the effectiveness of holding that asset as a hedge against intertemporal variation in the marginal utility of consumption. For Treasury Bonds of various maturities, we find significant positive relations. Our empirical findings support the conclusion that investors must sell bonds short to hedge shocks to marginal utility, because realized bond returns tend to be high (low) when investors least (most) desire an additional dollar of consumption. Implications for special cases of the general consumption-based model are also discussed.

1. Introduction

All consumption-based models of asset pricing imply that the relation between the conditional mean and conditional volatility of *any* asset reflects the effectiveness of the asset as a hedge against intertemporal variation in the marginal utility of consumption. The relation is negative if a long position in an asset hedges shocks to the marginal utility of consumption. The relation is positive if a long position adds to consumption risk. We estimate the relation between the conditional mean and conditional volatility of excess returns on U.S. Treasury securities and find evidence of significant positive relations for all maturities. Our full sample results indicate that long positions in Treasury Bonds do not hedge shocks to the marginal utility of consumption. To hedge effectively against such shocks an investor must sell short or sell futures on bonds. In terms of statistical significance and robustness

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to changes in methodology, the positive relation is especially reliable for bond maturities of 5 years or less, so short positions on shorter-maturity bonds are the most statistically reliable means for an investor to hedge the marginal utility of consumption.

The general consumption-based model upon which we base our tests requires only minimal assumptions. Models such as the capital asset pricing model (CAPM), intertemporal capital asset pricing model (ICAPM) of Merton (1973), the intertemporal asset pricing model of Campbell (1993), and the habit-persistence model of Campbell and Cochrane (1999) are special cases.[1] Specializations of the general model add additional structure, but do not change the implications that are the focus of our empirical tests. The intuition of the general model is straightforward. A pure hedging asset has realized returns that are perfectly positively correlated with the marginal utility of wealth.[2] It provides high payoffs during "bad times" when the marginal utility of consuming an additional dollar of wealth is high and low payoffs during "good times" when the marginal utility of consuming an additional dollar of wealth is low. The volatility of the asset's return is desirable and investors are willing to pay more for the asset, because holding the asset decreases intertemporal variation in the holder's marginal utility. Thus, the key characteristics of a hedging asset are a negative risk premium and a perfect negative correlation between the conditionally expected excess return and conditional volatility of the asset. On the other hand, an asset that has returns that are perfectly negatively correlated with the marginal utility of wealth provides high payoffs when times are good and low payoffs when times are bad. The volatility of the asset's return is undesirable because it increases intertemporal variation in the holder's marginal utility. The expected risk premium on such an asset is positive and perfectly positively correlated with its conditional volatility. A short, rather than long, position in the asset is required to hedge consumption risk. Our empirical results for bonds are consistent with the latter case, indicating that realized returns on bonds tend to be high in good times when the marginal utility of receiving an additional dollar of wealth is low.

The beauty of the general consumption-based model is that it provides a simple and straightforward test of the hedging effectiveness of any asset that requires only modeling the first two moments of the asset's return. The test does not require consumption data, nor does it require that the researcher choose a specific model of investor preferences. The model's predictions regarding the first two moments of returns hold for any asset, for any two periods of a multi-period model, and require no assumptions regarding complete markets, return distributions, time- or state-separable utility, or the existence of labor income or human capital.

In addition to evidence of hedging effectiveness, our results provide evidence regarding which special cases of the consumption-based model capture key aspects of asset returns. Our full sample results are consistent with the conclusion that realized returns on Treasury Bonds are high when investors least value, and low when investors most value, the benefits of an additional dollar of consumption. Thus, for a special case of the consumption-based model to accurately reflect investor preferences, it must explain why investors associate bad times of high marginal utility with periods of low realized and high expected bond returns. Special cases that assume that the marginal utility of consumption is a function of at most wealth and investment opportunities, such as the ICAPM specializations of Merton (1973) and Campbell (1993), do not do so. Unless one assumes that the coefficient of relative risk aversion is very low (less than one), these specialized models associate bad times with low expected returns. Explaining why investors associate bad times with high expected returns requires a model that captures the fact that investors are concerned not only with the wealth effects of holding assets, but with the fact that assets do poorly at particular times or in particular states of nature (recessions). For example, Campbell and Cochrane (1999) do so by adding an argument to the utility function, habit that enters nonseparably over time

Turning to empirical results, we find that neither the sign nor the significance of the estimated relation between bond risk and return is sensitive to changes in methodology known to influence inferences in the literature on stock risk and return. Specifically, the results are similar whether

[1] For detailed discussion of the relation of these and other asset pricing models to the general model see Cochrane (2006, 2007).
[2] Once the consumer/investor has optimized, the marginal utility of an additional dollar of wealth is the same for all uses.

the conditional variance is modeled using only financial conditioning variables, a simple generalized autoregressive conditional heteroskedasticity in mean (GARCH-M) model, a GARCH-M model that incorporates financial conditioning variables in the estimation of the conditional variance, or GARCH-M models that allow for asymmetries in the conditional variance equation. While all of our empirical models provide evidence consistent with a positive risk–return relation for Treasury Bonds, the strongest results are for the model that incorporates both financial conditioning information and GARCH effects in estimating the conditional variance. Thus, combining alternative methods of estimating the conditional variance reinforces inferences regarding the sign of the risk–return relation.

The general consumption-based model permits the reward to bond volatility to vary over time, so we examine the linearity and stability of the relation between conditional mean and conditional variance. For each model of conditional variance and each bond maturity, regression analysis indicates that financial conditioning information explains variation in bond excess returns that is not related to changes in the conditional variance. The fact that a time invariant linear model of the bond risk–return relation is rejected suggests that the reward to bond volatility does change over time.

To provide evidence on the impact of changing reward to volatility on the stability of the risk–return relation, we examine rolling correlations between "best estimates" of the conditional mean excess return and conditional variance. The rolling correlations show substantial variation over time in the short-term relation between bond risk and return. The rolling correlations for all maturities tend to move together, but the range of variation increases with bond maturity. For each maturity there are periods during which the rolling correlations are negative, which suggests that the hedging effectiveness of bonds may have varied during our sample period.

The remainder of this paper is organized as follows. Section 2 reviews related literature. Section 3 provides theoretical context. Section 4 describes the data. Section 5 presents our empirical model of conditional mean excess returns and diagnostic tests of the stability of the model. Section 6 presents our empirical results. Section 7 evaluates the linearity and stability of the relation between the conditional mean and conditional variance. Section 8 concludes.

2. Related literature

Two studies report direct evidence regarding the intertemporal relation between the conditional mean and conditional volatility of monthly bond returns. Engle, Lilein, and Robins (1987) use an ARCH-M framework to estimate the relation between the conditional mean and conditional standard deviation of monthly excess holding period returns on two-month Treasury bills and twenty-year AAA rated corporate bonds. They find positive coefficient estimates on volatility in the expected return regressions for both return series. The coefficient for the two-month bill is significant at the 0.01 level, while that for corporate bonds is significant at the 0.10 level. Campbell (1987) estimates the conditional mean and conditional variance of monthly excess returns on two-month Treasury bills, six-month Treasury bills, and a portfolio of five-to-ten-year Treasury Bonds, where both moments are modeled as functions of financial conditioning variables. Campbell (1987) reports correlations between the fitted moments of 0.625 for the two-month bill, 0.835 for the six-month bill, and 0.029 for the long-term bond portfolio. While the evidence reported in these studies is limited in terms of the bond maturities examined, the two studies are consistent in reporting a strong positive relation between risk and return for short-term bills and a weak positive relation for long-term bonds.[3] No study presents a direct test of the stability of the relation between conditional expected excess returns and volatilities for bonds.

Contrary to the case of bonds, there are many studies that report estimates of the relation between the conditional mean and conditional volatility of monthly stock market returns. Results are very sensitive to changes in the methodology used to estimate the conditional volatility. Since studies by

[3] In related work, Fama (1976) and Klemkosky and Pilotte (1992) document positive relations between excess returns and the volatility of the one-month bill rate for a variety of bill and bond maturities. Such results imply a positive relation between a bond's excess return and own volatility when the term structure is determined by a single state variable. However, Litterman and Scheinkman (1991) find that at least three state variables are required to adequately model the term structure.

Campbell (1987), Campbell and Ammer (1993), and Fama and French (1993) find that bond and stock excess returns are related to common predictor variables, robustness may be an issue for bonds as well as stocks. On the other hand Reilly, Wright, and Chan (2000) and Jones and Wilson (2004) document differences in the time series properties of stock and bond returns, so robustness may not be an issue. As a precaution, we explore changes in methodology know to influence results in the stock literature.[4]

A review of studies of monthly stock returns such as French, Schwert, and Stambaugh (1987), Glosten, Jaganathan, and Runkle (1993), Campbell (1987), Whitelaw (1994) and Harvey (2001) indicates that results are sensitive to whether the conditional variance is modeled using only financial conditioning variables, a simple GARCH-M model, a GARCH-M model that incorporates financial conditioning variables in the estimation of the conditional variance, or GARCH-M models that allow positive and negative shocks to returns to have different impacts on the conditional variance. We also use monthly data, so we examine the robustness of our results to the aforementioned changes in methodology.[5]

3. Theoretical context

Consider the intertemporal choice problem of a representative investor who maximizes the conditional expectation of the utility of current and future consumption. In that case, assets can be priced as the conditional expected value of the product of their payoff and a stochastic discount factor,

$$P_{i,t} = E_t[M_{t+1}(P_{i,t+1} + I_{i,t+1})], \tag{1}$$

where $P_{i,t}$ is the price of asset i at time t, $I_{i,t+1}$ is the asset's income at $t+1$, and M_{t+1} is the stochastic discount factor.[6] The discount factor is the marginal rate of substitution, defined as $M_{t+1} \equiv \beta U_C(C_{t+1}, \boldsymbol{x}_{t+1})/U_C(C_t, \boldsymbol{x}_t)$, where β is the time preference parameter and $U(C_t, \boldsymbol{x}_t)$ defines utility as a function of time t consumption, C_t, and a vector, $\boldsymbol{x}_t$, of other variables that enter into the utility function. Utility is assumed to be an increasing and concave function of consumption. The additional arguments, $\boldsymbol{x}_t$, admit the possibility that utility may be a function of other variables such as state variables and may be nonseparable over time, goods, or states of nature. The C subscript denotes the first derivative of utility with respect to consumption. Eq. (1) and the equations that follow hold for both real and nominal values as long as all values, including M_{t+1}, are expressed consistently in either real terms or nominal terms. They hold for any asset for any two periods of a multi-period model and require no assumptions regarding complete markets, return distributions, time- or state-separable utility, or the existence of labor income or human capital. Making such assumptions adds additional structure to the model, but does not change any of the implications discussed here.

Defining the gross return (one plus the net return) as $R_{i,t+1} = (P_{i,t+1} + I_{i,t+1})/P_{i,t}$, Eq. (1) can be rewritten in terms of asset returns as

$$1 = E_t[M_{t+1}R_{i,t+1}], \tag{2}$$

or, equivalently, by applying the definition of covariance, as[7]

$$1 = E_t[M_{t+1}] \cdot E_t[R_{t+1}] + Cov_t[M_{t+1}, R_{t+1}] \tag{2'}$$

4 For the 1950–1999 period Reilly et al. (2000) find that return volatility is more stable for stocks than for bonds, the ratio of stock market to bond market volatility is not stable, and the correlation between bond and stock returns varies widely. Jones and Wilson (2004) find similar results for the period 1871–2000.

5 We limit our study to parametric methods and monthly returns to keep the scope of the analysis manageable and provide a reasonably rich baseline for future study, while supplying results comparable to key findings in the stock literature. The mixed results of studies based on monthly stock return data motivated the exploration of a variety of alternative methodologies to estimate the stock risk-return relation, including the use of daily returns to estimate monthly volatility (see Ghysels, Santa-Clara, & Valkanov, 2005), the use of regime-switching models (see Whitelaw, 2000), and the use of measures of expected rather than realized return (see Jiang & Lee, 2009; Pastor, Sinha, & Swaminathan, 2008).

6 Eq. (1) can also be derived from the absence of arbitrage. See chapters 2 and 4 of Cochrane (2001) for a detailed discussion of the minimum requirements for Eq. (1) to hold.

7 By definition, $Cov_t[M_{t+1}, R_{t+1}] = E_t[M_{t+1}R_{t+1}] - E_t[M_{t+1}] \cdot E_t[R_{t+1}]$.

Eq. (2) says that expected *discounted* gross returns always equal one. The expanded expression (2′) introduces the key role that the covariance between an asset's return and the discount factor plays in the risk adjustment of expected return. For a given value of $E_t[M_{t+1}]$, expected gross returns must be inversely related to covariances in any cross-section of assets.

Before discussing the hedging implications of the model in detail, it is useful to examine implications specific to the pricing of default-free bonds. We begin with the gross return to a default-free bond that has a one-period maturity. This risk-free gross return, $R_{f,t}$, is known at time t, so Eq. (2) implies that

$$R_{f,t} = E_t[M_{t+1}]^{-1}. \tag{3}$$

Substituting for future prices in Eq. (1) and using the law of iterated expectations, the price of a τ-period-to-maturity risk-free discount (zero-coupon) bond that pays \$1 at maturity is

$$P_{\tau,t} = E_t[M_{t+1,t+\tau}], \tag{4}$$

where $E_t[M_{t+1,t+\tau}] = E_t[M_{t+1}M_{t+2}\ldots M_{t+\tau}]$, and the one-period return to holding the τ-period-to-maturity discount bond is:

$$R_{\tau,t+1} = \frac{P_{\tau,t+1}}{P_{\tau,t}} = \frac{E_{t+1}[M_{t+2,t+\tau}]}{E_t[M_{t+1,t+\tau}]} \tag{5}$$

Eq. (5) shows that the holding period return on a bond is a function of changes in expectations of future values of the stochastic discount factor over the bond's life. Any news or events that cause investors to adjust their expectations of future realizations of the marginal utility of consumption during the bond's life are reflected in bond returns and their volatilities. Since the price of any coupon bond can be expressed as the sum of prices of a series of discount bonds, the intuition behind Eq. (5) holds for coupon bonds as well.

To examine interemporal hedging issues, it is useful to multiply both sides of Eq. (2′) by $E_t[M_{t+1}]^{-1}$, substitute from Eq. (3), and rearrange terms to show that the one-period risk premium to holding *any* asset i is

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{1}{E_t[M_{t+1}]} Cov_t[M_{t+1}, R_{i,t+1}], \tag{6}$$

where Cov_t is the conditional covariance at time t. According to Eq. (6), an asset will earn a positive risk premium if its realized return is inversely related to M_{t+1}, that is, if the return is high when the marginal utility of consumption is low and low when marginal utility is high. However, a negative risk premium is indicated for hedging assets, that is, assets that have high payoffs when the marginal utility of consumption is high and low payoffs when marginal utility is low. Investors pay more for hedging assets, because hedging assets provide higher payoffs when additional consumption is most desired.

As a point of clarification, it is worth noting that the above definition of a hedging asset differs from that of a "hedge portfolio" as that term is often used in extensions and empirical tests of Merton's ICAPM. In those contexts a hedge portfolio is one that hedges against deteriorations in investment opportunities (decreases in expected future returns) by providing realized returns that are inversely related to expected returns. In the ICAPM, a long position in a hedge portfolio hedges the marginal utility of wealth only if the coefficient of relative risk aversion is greater than one.[8] If risk aversion is less than one, a portfolio that has realized returns that are positively related to shifts in investment opportunities is required to hedge the marginal utility of wealth. The ICAPM specializes the general

[8] The coefficient of relative risk aversion determines whether investors will increase or decrease consumption in response to changes in expected future returns. When risk aversion is greater than one, investors are not aggressive in seeking growth in planned consumption. They increase (decrease) both current and planned future consumption in response to an increase (decrease) in investment opportunities. In the contrary case, when risk aversion is less than one, investors are aggressive in seeking growth in planned consumption. In response to an increase in expected returns, they decrease current consumption to invest more in risky assets. Only in the high risk aversion case does an ICAPM hedging asset (one that provides high realized returns when investment opportunities are poor) do so during periods when the marginal utility of consumption is high.

consumption-based model. The ICAPM is derived with the assumption that the marginal utility of consumption is described by wealth and investment opportunities alone.

Substituting Eq. (5) into Eq. (6) produces the following expression for the excess return to the τ-period discount bond:

$$E_t[R_{\tau,t+1}] - R_{f,t} = -\frac{1}{E[M_{t+1}]} Cov_t \left[M_{t+1}, \frac{E_{t+1}[M_{t+2,t+\tau}]}{E_t[M_{t+1,t+\tau}]} \right]. \tag{7}$$

Eq. (7) demonstrates that the ex ante risk premium on a bond reflects the expected time series properties of M_{t+1} during the bond's maturity. Thus, bonds of adjacent maturities are likely to have similar return characteristics. Characteristics of short and long maturity bonds could be very different.

We follow the convention of using yield spreads as a conditioning variable in our empirical tests. Eq. (4) implies that the gross yield on a τ-period discount bond is

$$Y_{\tau,t} = \left(\frac{1}{P_{\tau,t}} \right)^{1/\tau} = E_t[M_{t+1,t+\tau}]^{-1/\tau}. \tag{8}$$

A comparison of Eq. (7) to Eqs. (3) and (8) shows why a bond's own yield spread contains information that is a useful for predicting bond excess returns.

Using the relationship between correlation and covariance to expand Eq. (6) provides the relation of the ex ante risk premium on *any* asset to that asset's own volatility[9]

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{vol_t[M_{t+1}]}{E_t\,[M_{t+1}]} vol_t[R_{i,t+1}] corr_t[M_{t+1}, R_{i,t+1}], \tag{9}$$

where vol_t is the conditional standard deviation, the ratio $vol_t[M_{t+1}]/E_t[M_{t+1}]$ is the slope of the mean-variance frontier, and $corr_t$ is the conditional correlation. The correlation summarizes the hedging properties of an asset and determines the sign of the relation between the first and second conditional moments of the asset's excess return. Variation over time in the slope or the correlation will cause the risk–return relation to vary as well.

Summarizing, three main conclusions can be drawn from the general model of asset pricing. First, the sign of the relation between a bond's excess return and conditional volatility depends on the extent to which a long position in the bond serves as an intertemporal hedge against shocks to the marginal utility of consumption. Second, risk–return relations differ across bond maturities. The difference is likely small for adjacent maturity bonds and potentially large for short versus long-term bonds, because the holding period return for each bond depends on changes during the holding period in expected values of the stochastic discount factor over the remaining life of the bond. Third, the relation between bond risk and return may vary over time due to changes in the slope of the mean-variance frontier or changes in the correlation between the asset's return and the stochastic discount factor. In the empirical section of this paper, we focus on documenting the sign of the bond risk–return relation for the full sample period, the consistency of the relation across bond maturities, and the short-term stability of the relation.

4. Data and descriptive statistics

Data are from the *Center for Research in Security Prices* (*CRSP*). Returns are one-month holding period returns. Returns and yields on one-month and three-month to maturity Treasury bills are from the Fama Treasury Bill Term Structure Files. Returns on five Treasury Bond portfolios are from the Fama Maturity Portfolios Returns File with bonds grouped by maturities in one year intervals. Thus, the bond portfolios consist of bonds with maturities of less than 1, 1–2, 2–3, 3–4, and 4–5 years. Only non-callable, non-flower bonds and notes are included in the portfolios. Yields that correspond to the portfolio returns are from the Fama-Bliss Discount Bonds File. Each yield is for the discount bond at the upper bound of maturity allowed in a portfolio. We use returns and yields on the ten-year

[9] By definition, $corr_t[M_{t+1}, R_{i,t+1}] = cov_t[M_{t+1}, R_{i,t+1}]/(vol_t[M_{t+1}]vol_t[R_{i,t+1}])$.

Table 1
Descriptive statistics for Treasury Bond excess returns.

Panel A: Monthly Excess Return ($R_{\tau,t+1} - R_{f,t}$)

Maturity (months)	Mean (×100)	Std. Dev. (×100)	Skewness	Kurtosis	JB	Q(12)	ρ_1	ρ_2	ρ_3	ρ_{12}
$\tau \approx 3$	0.0521	0.0909	2.47	15.39	4357.3***	151.5***	0.32	0.10	0.06	0.02
$0 < \tau \leq 12$	0.0658	0.2591	1.49	17.91	5665.1***	79.0***	0.19	−0.04	−0.01	−0.08
$12 < \tau \leq 24$	0.1049	0.6489	0.84	15.88	4135.9***	59.4***	0.19	−0.07	−0.05	−0.01
$24 < \tau \leq 36$	0.1316	0.9890	0.63	13.47	2726.0***	41.6***	0.14	−0.06	−0.05	0.01
$36 < \tau \leq 48$	0.1476	1.2386	0.17	7.87	582.6***	31.7***	0.13	−0.05	−0.05	0.04
$48 < \tau \leq 60$	0.1432	1.4523	0.18	6.78	352.6***	30.9***	0.13	−0.07	−0.05	0.04
$\tau \approx 120$	0.1588	2.2266	0.29	4.44	58.8***	15.3	0.06	−0.06	−0.02	0.02
$\tau \approx 240$	0.1814	2.9069	0.38	5.62	182.8***	19.3*	0.04	−0.09	−0.05	−0.01

Panel B: Squared Excess Returns ($R_{\tau,t+1} - R_{f,t})^2$

Maturity (months)	Mean (×100)	Std. Dev. (×100)	Q(12)	ρ_1	ρ_2	ρ_3	ρ_6	ρ_{12}
$\tau \approx 3$	0.0001	0.0004	304.5***	0.52	0.15	0.07	0.10	0.08
$0 < \tau \leq 12$	0.0007	0.0029	219.4***	0.36	0.20	0.12	0.18	0.14
$12 < \tau \leq 24$	0.0043	0.0166	171.9***	0.19	0.31	0.11	0.23	0.12
$24 < \tau \leq 36$	0.0099	0.0351	151.7***	0.14	0.33	0.08	0.22	0.11
$36 < \tau \leq 48$	0.0155	0.0406	202.2***	0.17	0.32	0.14	0.26	0.14
$48 < \tau \leq 60$	0.0213	0.0511	187.7***	0.13	0.28	0.11	0.28	0.15
$\tau \approx 120$	0.0497	0.0932	160.0***	0.18	0.26	0.14	0.08	0.17
$\tau \approx 240$	0.0847	0.1837	113.2***	0.24	0.21	0.19	0.10	0.10

The time series is from January 1961 to December 2009 with 588 observations. The Jarque–Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of a data series from normality, based on the levels of skewness and excess kurtosis. The JB statistic is χ^2 distributed with 2 degrees of freedom. The Q(12) statistic tests for autocorrelation in the first 12 lags. It is χ^2 distributed with 12 degrees of freedom based on the number of lags tested. The autocorrelation coefficient is denoted by ρ_t, where t is the lag, in months. ***, **, * denote significance for the JB or Q(12) test at the 0.01, 0.05, and 0.10 levels, respectively for a one-tailed test.

and twenty-year constant maturity bonds from the *CRSP* Fixed Term Indices Files to represent longer maturity bonds.[10] Where possible, *CRSP* uses a non-callable, non-flower bond in constructing the Fixed Term Indices Files. The sample period is January 1961 to December 2009. We start with January 1961, because there are often substantial gaps in prior months between the desired and available maturities for the ten- and twenty-year constant maturity bonds. Eight excess return series are calculated by subtracting the return to the one-month bill from the holding period returns on the three-month bill, each of the five bond portfolios, and the ten- and twenty-year constant maturity bonds.

We report descriptive statistics for the excess return series in Panel A of Table 1. Both the mean and standard deviation of monthly excess returns tend to increase with maturity, standard deviations rise more sharply. These results are consistent with Pilotte and Sterbenz (2006), who find that bond Sharpe ratios decline with maturity.

The Jarque–Bera (JB) statistics, a goodness-of-fit test of the departure of the distribution of a data series from the normal, reject normality at the 0.01 level for each excess return series. An examination of the skewness and kurtosis of the excess return series indicates that the rejection of normality is due predominately to excess kurtosis relative to the normal distribution. The Q(12) statistics reject the null hypothesis of no autocorrelation in the first 12 lags at the 0.01 level for six of the eight series and at the 0.10 level for one series. Reported autocorrelations indicate that these rejections are due mostly to positive first order autocorrelation in the excess returns. Higher order correlations are close to zero and the pattern of autocorrelations is consistent with stationarity of all of the excess return series.

[10] We use the twenty-year and not the thirty-year bond from the Fixed Term Indices File because there are several years where both series are based on the same bond and the gap between actual and desired maturity is generally smaller for the twenty-year bond. The disadvantage of using constant maturity bonds rather than portfolios is that the realized return is more sensitive to idiosyncratic variation in the price of a single bond.

To examine aspects of the volatility of excess returns, we report descriptive statistics for squared excess returns in Panel B of Table 1. Panel B shows that both the mean and standard deviation of squared excess returns increase with maturity. The $Q(12)$ statistics and autocorrelations reported in Panel B indicate substantial positive autocorrelation in squared excess returns that is more persistent than the positive autocorrelation in excess returns. These statistics suggest the existence of autoregressive conditional heteroskedasticity in each excess return series.

5. Excess return model and model evaluation

In this section we present our empirical model of conditional mean excess returns and carry out diagnostic tests to evaluate the stability of the model. The residuals of this model are used in a later section of this paper to model conditional volatility using predetermined financial conditioning information as instrumental variables.

5.1. Estimating conditional mean excess returns

In order to estimate the conditional volatility of a bond's excess returns, it is useful to isolate the predictable and the unpredictable components of those returns. To do so, we model the conditional mean excess return by regressing excess returns on predetermined conditioning variables. An obvious choice for a conditioning variable is a bond's own yield spread, defined as the beginning of period difference between the bond's yield to maturity and the one-month T-bill rate. The yield spread has been shown to have predictive power for bond excess returns in prior studies by Campbell (1987), Fama (1990), and Pilotte and Sterbenz (2006).[11] Based on the positive first order autocorrelations in excess returns reported in Table 1, we also include the one-month lag of each bond's excess return as a conditioning variable. Thus, our model of excess returns is:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}(Y_{\tau,t} - R_{f,t}) + \alpha_{\tau,2}(R_{\tau,t} - R_{f,t-1}) + \varepsilon_{\tau,t+1} \tag{10}$$

where t subscripts denote when a variable is observed, $R_{\tau,t+1}$ is the uncertain return from holding from time t to t+1 a bond of maturity τ, $R_{f,t}$ is the risk-free return known at time t and earned by holding a one-month bill from t to t+1, $Y_{\tau,t}$ is the yield-to-maturity observed at time t on a bond of maturity τ, and $\varepsilon_{\tau,t+1}$ is the error term.

Stambaugh (1999) shows that the conventional t-test of return predictability is biased when a regressor is highly persistent and its changes are highly correlated with subsequent returns. Since yield spreads are both highly persistent and their innovations are likely correlated with subsequent returns, we implement the pretest procedure developed by Campbell and Yogo (2005) and Campbell and Yogo (2006) to check on the validity of the t-statistics associated with the yield spreads in our regressions. Results of these pretests (not shown) indicate that the conventional t-test leads to valid inference in all of our regressions of bond excess returns on yield spreads. Because our excess return series are clearly stationary, as indicated by the autocorrelations reported in Table 1, conventional t-tests are valid for the lagged excess returns as well.

The results of ordinary least squares (OLS) estimation of regression Eq. (10) are reported in Table 2. The standard errors are adjusted for autocorrelation and heteroskedasticity. The yield spread is significant at the 0.01 level for three, at the 0.05 level for four, and at the 0.10 level for one of the eight bond maturities. The lagged excess return is significant at the 0.01 level for six bond maturities and the 0.10 level for one maturity. The regression R-square ranges from a low of 0.02 for the twenty-year bond to a high of 0.11 for the three-month bill. These results document predictable variation in bond excess returns for all maturities.

Table 2 also contains test statistics that examine aspects of the regression errors. The JB statistics reject normality of the residuals at the 0.01 level for every regression. The White statistics reject the

[11] Fama (1990) shows that the yield spread contains the market's estimate of the ex ante risk premium and should reflect variation in that premium. The idea that a bond's own term spread contains information that is useful for predicting bond excess returns also is supported by a comparison of our Eq. (7), to Eqs. (3) and (8).

Table 2
Ordinary least squares regressions of excess returns on conditioning variables.

Maturity	Constant	$Y_{\tau,t} - R_{f,t}$	$R_{\tau} - R_{f,t-1}$	R^2	JB	White-Hetero.	LM-Serial Corr.	LM-ARCH
$\tau \approx 3$	0.000**	0.278***	0.270***	0.11	4300.5***	97.1***	35.6***	112.6***
	(0.000)	(0.210)	(0.090)					
$0 < \tau \leq 12$	0.000	0.5759*	0.245***	0.05	8047.5***	49.4***	64.3***	94.2***
	(0.000)	(0.299)	(0.059)					
$12 < \tau \leq 24$	−0.000	1.178**	0.229***	0.05	5454.4***	10.1**	41.7***	88.4***
	(0.000)	(0.527)	(0.047)					
$24 < \tau \leq 36$	−0.000	1.476**	0.174***	0.04	3572.7***	9.2*	30.0***	85.4***
	(0.001)	(0.728)	(0.043)					
$36 < \tau \leq 48$	−0.001	1.852**	0.158***	0.04	661.2***	22.6***	20.1*	101.2***
	(0.001)	(0.827)	(0.045)					
$48 < \tau \leq 60$	−0.001	1.946***	0.149***	0.03	435.9***	14.3***	19.9*	90.6***
	(0.001)	(0.862)	(0.041)					
$\tau \approx 120$	−0.002	2.617**	0.074*	0.02	48.2***	33.4***	16.1	85.5***
	(0.002)	(1.057)	(0.041)					
$\tau \approx 240$	−0.003*	3.111***	0.038	0.02	215.9***	35.4***	21.9**	58.3***
	(0.002)	(1.115)	(0.045)					

The time series is from January 1961 to December 2009. Regressions of the monthly excess return ($R_{\tau,t+1} - R_{f,t}$) on the beginning-of-period yield spread ($Y_{\tau,t} - R_{f,t}$), and, the one-month lag of the excess return ($R_{\tau,t} - R_{f,t-1}$). The Jarque–Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of the regression residuals from normality. The JB statistic is χ^2 distributed with 2 degrees of freedom. The White statistic is a test for heteroskedasticity that is χ^2 distributed with 6 degrees of freedom. The Breusch–Godfrey Lagrange Multiplier (LM-Serial-Corr.) statistic is a test for serial correlation that is χ^2 distributed with 12 degrees of freedom due to the test for serial correlation for up to 12 lags. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Newey–West autocorrelation and heteroskedasticity consistent standard errors are in parentheses. ***, **, * denote significance at 0.01, 0.05, and 0.10 levels, respectively for a two-tailed test; one-tailed test for JB, White, and LM tests.

null hypothesis of no heteroskedasticity at the 0.01 level for six maturities, the 0.05 level for one maturity, and at the 0.10 level for the remaining maturity. The Breusch–Godfrey Lagrange Multiplier statistics reject the null hypothesis of no serial correlation at the 0.01 level in four regressions, at the 0.05 level in one regression, and at the 0.10 level in two regressions. Engle's Lagrange Multiplier ARCH statistics reject the null hypothesis of no autoregressive conditional heteroskedasticity in the residuals at the 0.01 level in every regression. In brief, the regression residuals are non-normally distributed, heteroskedastic, autocorrelated, and show strong evidence of ARCH effects. We consider these aspects of shocks to bond excess returns in the models of the risk–return relation that appear later in this paper.

5.2. *Evaluation of excess return model*

Klemkosky and Pilotte (1992) present evidence of shifts in the stochastic process that generates Treasury Bond risk premiums around October 1979 and October 1982 changes in monetary policy.[12] Thus, we conduct a variety of diagnostic tests to check the specification of our model of excess returns.[13] Due to the large quantity of diagnostic test results, we discuss them but do not report them in tabular form.

Our first set of diagnostic tests is based on recursive least squares estimation of Eq. (10) for each bond maturity. We examine plots against time of the recursive coefficients and two standard error bands around the coefficients for each bond maturity. These plots suggest that the regression coefficients are stable over time. We also apply the CUSUM and CUSUM of squares tests (see Brown, Durbin, & Evans, 1975) that are based on plots against time of the cumulative sums of the recursive residuals and their squared values, respectively. Using the 0.05 significance level, the CUSUM

[12] These dates reflect changes in the Federal Reserve's focus on targeting interest rates and monetary aggregates. Specifically, during 1979–1982 the Fed experimented with using non-borrowed reserves as a target for monetary policy.
[13] Klemkosky and Pilotte (1992) reject the stability of a model of the relation between bond excess returns and short-rate volatility.

tests suggest model stability while the CUSUM of squares tests suggest instability. Overall, the results based on recursive estimation suggest parameter stability but changing variance over the full sample period.

Our second set of diagnostic tests is Wald tests of structural change. Model stability is tested for each bond for each of the five possible monetary regime pairs. The results of tests that assume unequal subperiod variances never reject coefficient stability at the 0.05 level and reject it at the 0.10 level in only one instance. The results of tests that assume equal subperiod variances consistently reject model stability. The Wald test results are consistent with the recursive least squares results in suggesting coefficient stability but changing variance across monetary regimes.

Overall, our specification tests support two conclusions. First, the assumption of coefficient stability over the full sample period is a reasonable one, so our method of estimating conditional mean excess returns appears adequate. Second, the volatility of return shocks varies over time, suggesting that an examination of the relation between excess returns and conditional volatility is well motivated. In the next section, we use models of conditional volatility to examine the relation between bond risk and return.

6. The relation between excess returns and conditional volatility

In this section, we estimate the empirical relation between bond risk and return. Since the method chosen to model conditional volatility is critical to the results of estimating the monthly risk–return relation in the stock literature, we test three specifications of the conditional variance of bond excess returns.[14] We pay special attention to the decision to include or exclude financial conditioning information in the model of conditional variance, because it determines the sign of the estimated risk–return relation for stocks. Our first model estimates conditional variances using predetermined financial conditioning information. Given the strong evidence of ARCH effects in excess returns reported in Table 2, our second model is a simple GARCH-M model. Our third model incorporates both financial conditioning variables and GARCH effects.

6.1. *Instrumental variables estimation using financial conditioning information*

For each bond maturity, τ, we estimate the following instrumental variables regression:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\varepsilon^2 + \mu_{\tau,t+1}, \tag{11}$$

where the $\varepsilon_{\tau,t+1}$ are the residuals from the estimation of Eq. (10) model of excess returns, the slope coefficient $\alpha_{\tau,1}$ is the estimate of the relation between the bond's expected excess return and conditional volatility, and $\mu_{\tau,t+1}$ is the error term. The intercept, $\alpha_{\tau,0}$, provides a check on the empirical specification of the risk–return model, because Eq. (9) indicates that the intercept will equal zero if the model specification is adequate. For instruments we consider lags of the squared residuals, the conditioning variables used to estimate the excess return model, and the one-month Treasury bill return. We include the one-month T-bill rate because of the historically positive relation between interest rate volatility and the level of interest rates, and because of the common use of the short-term interest rate to model volatility in term structure models.[15] An initial examination of the relations between the squared residuals and the candidate instruments indicates that the one-month bill rate and six lags of the squared residuals encompass the candidates that are most useful in modeling conditional volatility. We expect shocks to bond excess returns to be correlated across maturities, so we improve the efficiency of our estimates by choosing an estimation method that takes into account the cross-equation correlations in the error terms. We use the Generalized Method of Moments (GMM) to estimate Eq. (11) simultaneously for all bond maturities. Standard errors are Newey–West heteroskedasticity and autocorrelation consistent.

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[14] We repeat each test using the standard deviation and log of conditional variance as the volatility measures. Results for these alternative specifications are discussed in the robustness section that appears later in the paper.

[15] Because of concerns regarding the possible non-stationarity of the one-month rate, we repeat the estimation excluding it from the list of instruments. Results are qualitatively the same.

Table 3
Instrumental variables estimation of risk-return relation for Treasury Bonds.

Maturity	Constant ($\times 10^4$)	Slope	LM-ARCH	LM-Serial Corr.	JB	AR(1) for predicted $\varepsilon^2_{\tau,t+1}$
$\tau \approx 3$	3.350***	284.423***	52.3***	54.3***	17,660.1***	0.881***
	(0.289)	(14.182)				(0.021)
$0 < \tau \leq 12$	5.280***	24.131***	96.7***	55.0***	2451.4***	0.981***
	(0.633)	(3.208)				(0.009)
$12 < \tau \leq 24$	8.010***	8.391***	78.5***	47.1***	3023.1***	0.538***
	(1.670)	(1.270)				(0.051)
$24 < \tau \leq 36$	10.090***	4.857***	75.2***	29.3***	1867.9***	0.553***
	(2.590)	(0.915)				(0.037)
$36 < \tau \leq 48$	11.320***	3.840***	95.1***	24.5***	708.7***	0.714***
	(3.460)	(0.944)				(0.032)
$48 < \tau \leq 60$	13.990***	0.782	85.1***	23.6***	286.6***	0.639***
	(4.350)	(0.994)				(0.035)
$\tau \approx 120$	2.810	3.813***	64.2***	16.1	68.6***	0.953***
	(8.950)	(1.148)				(0.013)
$\tau \approx 240$	17.970*	0.232	49.7***	18.5*	149.2***	0.666***
	(10.330)	(0.800)				(0.034)

Generalized method of moments (GMM) system estimation incorporates the use of instrumental variables and considers the cross-equation correlations in the error terms. The following system of equations is estimated:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\varepsilon^2_{\tau,t+1} + \mu_{\tau,t+1},$$

where, τ is the number of months of bond maturity: $\tau \approx 3$, $0 < \tau \leq 12$, $0 < \tau \leq 24$, $0 < \tau \leq 36$, $0 < \tau \leq 48$, $0 < \tau \leq 60$, $\tau \approx 120$, and $\tau \approx 240$, time t = 1, 588 represents the beginning of months from January 1961 to December 2009, ε_{t+1} is the residual from the OLS regressions in Table 2, and μ_{t+1} is the error term. The instrumental variables are the one-month return on the one month T-Bill ($R_{f,t}$) and the first six monthly lags of the squared residuals. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. The Breusch–Godfrey Lagrange Multiplier (LM-Serial-Corr.) statistic is a test for serial correlation that is χ^2 distributed with 12 degrees of freedom due to the test for serial correlation for up to 12 lags. The Jarque–Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of the regression residuals from normality. The JB statistic is χ^2 distributed with 2 degrees of freedom. The AR(1) coefficient is the first order autoregressive coefficient for the fitted values of $\varepsilon^2_{\tau,t+1}$. Newey–West heteroskedasticity and autocorrelation consistent standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05, and 0.10 levels respectively; two-tailed test for regression parameters, one-tail test for Q and JB statistics.

Results of the system estimation of Eq. (11) are reported in Table 3. The slope coefficient is significant at the 0.01 level for the 3 month bill, the four bond portfolios of maturities less than or equal to 48 months, and the 120-month bond. The slope coefficient is statistically insignificant for the 48–60-month portfolio and the 240-month bond. Thus, six of our eight maturities produce evidence of a significant positive relation between bond risk and return. In terms of statistical significance, the positive relation tends to be more reliable the shorter the bond maturity.

The intercepts reported in Table 3 are significant at the 0.01 level in six regressions and at the 0.10 level in one regression. The prevalence of significant nonzero intercepts suggests that the IV approach is not adequate for modeling the risk–return relation, as Eq. (9) predicts a zero intercept for a well specified model.

To facilitate comparison of the persistence of the conditional variance estimates across differently parameterized models, we follow Glosten et al. (1993) who regress the conditional variance estimate for each model on a constant and the lagged value of the estimate. These first order autoregressive coefficients are reported for each model that we estimate. For the results of instrumental variables estimation reported in Table 3, the first order autoregressive coefficient is estimated for the predicted values of the $\varepsilon^2_{\tau,t+1}$ from the system estimation of Eq. (11). These AR(1) coefficients indicate that there is substantial persistence in the conditional variance estimates.

The LM-ARCH statistics reported in Table 3 reject, at the 0.01 level, the null hypothesis of no ARCH effects in the first 12 lags of the residuals of each equation. The LM-Serial Correlation and JB statistics are consistent with results reported in Table 2, rejecting the nulls of no auto-correlation and the normality of the residuals. Since GMM requires no distributional assumption, parameter estimates are consistent despite the lack of normally distributed residuals. Because the

IV approach to estimating conditional volatility does a poor job of capturing the ARCH effects in our excess return data, GARCH estimation may provide more accurate estimates of conditional volatility and improve the efficiency of estimates. We use GARCH estimation in the models that follow.

6.2. *GARCH-M estimation*

A natural way to estimate the relation between bond risk and return is with the following simple GARCH-M model of conditional variance:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1} \tag{12}$$

$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \upsilon_{\tau,t+1} \tag{13}$$

Estimation is by the method of maximum likelihood. In light of the evidence in Table 1 that excess returns are not normally distributed due to excess kurtosis, we estimate the GARCH-M system assuming that the conditional distribution for the error term is the Generalized Error Distribution (GED). The GED is less restrictive than the normal as it accommodates kurtosis, although it does not accommodate skewness.[16] The GED distribution nests the Student's *t*-distribution and normal distribution.

Table 4 contains the results for GARCH-M estimation. For each maturity, the GED parameter differs significantly from 2, the value for the normal distribution, at either the 0.01 or 0.05 significance levels.[17] The Lagrange Multiplier ARCH statistics indicate that the model is effective at removing most of the ARCH effects from the regression residuals. The coefficient sum, $\beta_{\tau,1} + \beta_{\tau,2}$, is close to one in every variance equation. A sum of one is indicative of the integrated GARCH (IGARCH) process identified by Engle and Bollerslev (1986), which allows for shocks to have a permanent effect on the conditional variance. An IGARCH process is not covariance-stationary but is strictly stationary under conditions identified in Nelson (1990).[18] Similarly, the AR(1) coefficients for the conditional volatility estimates range from 0.93 to 0.97. This confirms the presence of substantial persistence in conditional volatility. The persistence in volatility, as measured by the AR(1) coefficient, is generally greater than that reported in Table 3 for the instrumental variables estimation.

The coefficients on conditional variance in the mean equations are all positive. They are significant at either the 0.01 or 0.05 level for all maturities less than or equal to 60 months and significant at the 0.10 level for the 240-month bond. The risk–return relation is insignificant only for the 120-month bond. Thus, the GARCH-M specification of conditional variance and the IV specification based on financial conditioning information both provide evidence that there is a positive relation between bond risk and return. In terms of statistical significance, both specifications indicate that the positive relation tends to be more reliable the shorter the bond maturity.

Contrary to the case for the IV specification, the intercepts for the GARCH-M regressions generally do not differ significantly from zero. The exceptions are the regressions for the 3-month bill and the portfolio of bonds that are very close (less than 12 months remaining) to maturity. Thus, the GARCH-M approach appears to be a superior model specification.

[16] The GED is a restricted version of the skewed generalized error distribution (SGED). Although it may seem intuitive that a less restrictive distribution is always better, since the non-normality of the error term is not driven by skewness, a loss of efficiency would obtain from over-parameterization of the distribution if specified with the more general SGED.

[17] Although not shown, χ^2 distributed goodness-of-fit log-likelihood ratio tests (one degree of freedom) comparing the fits of the GED and the normal distributions for each maturity indicate that the GED provides a statistically-significantly better fit than the normal.

[18] Nelson shows that an IGARCH(1,1) process with a positive drift is strictly stationary and ergodic. The unconditional density for such a process is the same for all *t*.

Table 4
GARCH-M estimation of risk-return relation for Treasury Bonds.

Maturity	Mean equation		Variance equation			GED parameter	LM-ARCH	Log-L	AR(1) coefficient for $\sigma^2_{\tau,t+1}$
	Constant ($\times 10$)	$\sigma^2_{\tau,t+1}$	Constant ($\times 10^8$)	$\gamma^2_{\tau,t}$	$\sigma^2_{\tau,t}$				
$\tau \approx 3$	0.002***	209.005***	0.511*	0.233***	0.793***	1.145***	11.0	3565.6	0.956***
	(0.000)	(39.148)	(0.267)	(0.044)	(0.027)	(0.092)			(0.012)
$0 < \tau \leq 12$	0.003***	45.948***	6.350*	0.222***	0.786***	1.425***	6.3	2922.2	0.955***
	(0.000)	(12.564)	(2.88)	(0.045)	(0.037)	(0.118)			(0.012)
$12 < \tau \leq 24$	0.002	17.014***	36.000*	0.146***	0.856***	1.436***	19.4*	2294.6	0.968***
	(0.002)	(6.201)	(18.900)	(0.031)	(0.029)	(0.112)			(0.010)
$24 < \tau \leq 36$	0.001	9.768**	57.500*	0.138***	0.871***	1.385***	18.1	2012.8	0.969***
	(0.003)	(4.231)	(31.800)	(0.028)	(0.023)	(0.102)			(0.010)
$36 < \tau \leq 48$	0.001	7.976**	74.200**	0.145***	0.869***	1.382**	14.7	1849.9	0.970***
	(0.004)	(3.564)	(37.600)	(0.030)	(0.023)	(0.102)			(0.010)
$48 < \tau \leq 60$	−0.004	6.965**	88.700**	0.126***	0.886***	1.347***	21.3**	1742.2	0.973***
	(0.005)	(3.150)	(41.600)	(0.026)	(0.020)	(0.101)			(0.010)
$\tau \approx 120$	−0.000	2.485	49.300	0.228***	0.816***	1.486***	11.6	1484.5	0.933***
	(0.006)	(1.907)	(76.800)	(0.046)	(0.030)	(0.106)			(0.015)
$\tau \approx 240$	−0.006	2.736*	216.000	0.123***	0.893**	1.425***	8.3	1322.8	0.968***
	(0.011)	(1.660)	(211.000)	(0.031)	(0.025)	(0.084)			(0.011)

The results below are the GARCH-M regressions for the monthly excess return on the T-Bond ($R_{\tau,t+1} - R_{f,t}$) with conditional variance in the mean equation. The estimated models are:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1}$$
$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \upsilon_{\tau,t+1}$$

The time series is from January 1961 to December 2009 with 588 observations. The conditional distribution for the error term is the generalized error distribution (GED) to address non-normality of the errors, where the GED parameter (k) is the kurtosis parameter that accommodates fat tails. The GED nests the normal distribution and becomes the normal if k is equal to 2. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Log-L is the value of the log likelihood function. The AR(1) coefficient is the first order autoregressive coefficient for the fitted values of $\sigma^2_{\tau,t+1}$. Standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05 and 0.10 levels, respectively; two-tailed test for regression and GED parameters, one-tailed test for LM-ARCH.

6.3. GARCH-M estimation with financial conditioning information

Our third model of conditional volatility incorporates both financial conditioning variables and GARCH effects:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1} \quad (14)$$

$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1} \quad (15)$$

Results, reported in Table 5, indicate that incorporating both financial conditioning variables and GARCH effects in the model of conditional variance provides stronger evidence of a positive relation between bond risk and return than does the simple GARCH-M estimation of Table 4. In the mean equation, the coefficient on the variance term is positive and significant at the 0.01 level for four bond maturities and at the 0.05 level for three bond maturities. Moreover, as is the case for the simple GARCH-M regressions, the intercepts for the GARCH-M regressions that incorporate financial conditioning variables in the variance equation generally do not differ significantly from zero. The model seems well specified for all but the shortest-term bonds.

An examination of the results for the variance equation indicates that the one-month rate is significant (0.05 level or lower) in explaining the conditional variance of every bond maturity. The significance of the yield spread (0.01 level) in explaining conditional variance is limited to the 3-month bill. The lagged excess return is significant (0.05 level) only for the 120-month bond.

In Table 5, the GED parameters differ significantly from the value for the normal distribution (0.01 level) in every regression. The Lagrange Multiplier ARCH statistics indicate that the model is effective at removing most of the ARCH effects from the regression residuals. For each maturity, the inclusion of financial conditioning information in the variance equation increases the value of the log-likelihood function relative to the value reported in Table 4 for simple GARCH-M estimation. The persistence in conditional volatility, as measured by the AR(1) coefficient, is usually close to that reported in Table 4 for the simple GARCH model.

6.4. Additional robustness tests

As a robustness check, all three models are estimated using the conditional standard deviation and the log of conditional variance rather than the conditional variance to estimate the risk–return relation. While these changes do not materially alter our conclusions, there are systematic effects on the *p*-values for the coefficient on the conditional volatility measure. For instrumental variables estimation using financial conditioning information, using the conditional standard deviation tends to raise *p*-values slightly. For GARCH-M estimation, both with and without conditioning variables, using the conditional standard deviation tends to lower *p*-values slightly. The preponderance of results remains consistent with a positive risk–return relation.

We also check the robustness of our results to the use of asymmetric GARCH-M models that allow positive and negative shocks to returns to have different impacts on the conditional volatility. Contrary to the existing evidence for stocks, for which asymmetries are significant determinants of conditional volatility that cause the sign of the risk–return relation to reverse, we find that these asymmetries are insignificant in determining the conditional volatilities of bonds.

We also explore the use of alternatives to the GED distribution for estimating GARCH models when regression residuals are not conditionally normally distributed. We repeat estimation of all GARCH models using the Student's *t*-distribution and using the quasi-maximum likelihood method of Bollerslev and Wooldridge (1992). Our conclusions are robust to these changes in the specification of the conditional distribution for errors.

We use GMM system estimation of Eq. (11) to produce our estimates of the risk–return relation that are based on modeling the conditional variance using only financial conditioning information. Advantages of the GMM estimator are that it takes into account the cross-equation correlations in the error terms and is robust to heteroskedasticity and autocorrelation of unknown form. As a check on the importance of these advantages we also estimate Eq. (11) using three-stage least squares (3SLS) and single-equation estimation. 3SLS accounts for the cross-equation correlations in the error term and

Table 5
GARCH-M estimation of risk-return relation with variance conditioning variables.

Maturity	Mean equation		Variance equation						GED parameter	LM-ARCH	Log-L	AR(1) coefficient for $\sigma^2_{\tau,t+1}$
	Constant ($\times 10^4$)	$\sigma^2_{\tau,t+1}$	Constant ($\times 10^6$)	$\sigma^2_{\tau,t}$	$\gamma^2_{\tau,t}$	$R_{f,t}$ ($\times 10^4$)	$Y_{\tau,t} - R_{f,t}$ ($\times 10^4$)	$R_\tau - R_{f,t-1}$ ($\times 10^4$)				
$\tau \approx 3$	1.000***	719.158***	−0.018***	0.410***	0.161***	0.240***	1.490***	1.290***	1.100***	27.9***	3592.7	0.818***
	(0.150)	(91.756)	(0.004)	(0.062)	(0.029)	(0.044)	(0.541)	(0.347)	(0.077)			(0.024)
$0 < \tau \le 12$	2.510***	59.944***	−0.049	0.780***	0.182***	0.434***	0.562	0.255	1.464***	10.3	2928.1	0.957***
	(0.560)	(14.197)	(0.038)	(0.040)	(0.041)	(0.157)	(0.693)	(0.610)	(0.126)			(0.012)
$12 < \tau \le 24$	1.500	21.271***	0.700*	0.871***	0.104***	3.750***	0.824	0.729	1.472***	22.3**	2301.3	0.962***
	(1.940)	(6.865)	(0.412)	(0.028)	(0.025)	(1.240)	(3.250)	(1.380)	(0.123)			(0.009)
$24 < \tau \le 36$	0.181	12.264***	−2.910**	0.877***	0.102***	11.750***	4.470	1.740	1.446***	17.3	2020.8	0.975***
	(3.000)	(2.717)	(1.270)	(0.028)	(0.025)	(4.030)	(6.760)	(2.380)	(0.116)			(0.009)
$36 < \tau \le 48$	−0.298	8.404**	−4.680**	0.889***	0.105***	17.730**	3.940	−2.940	1.491***	9.7	1860.8	0.982***
	(3.280)	(3.451)	(2.350)	(0.028)	(0.027)	(7.180)	(11.820)	(2.570)	(0.129)			(0.008)
$48 < \tau \le 60$	−4.820	6.964**	−7.150*	0.904***	0.092***	25.650**	3.840	−3.100	1.447***	19.8*	1753.5	0.984***
	(3.700)	(2.938)	(3.970)	(0.027)	(0.024)	(11.510)	(18.570)	(3.250)	(0.123)			(0.007)
$\tau \approx 120$	−3.970	2.774	−23.100**	0.852***	0.146***	72.36**	51.31	−10.100**	1.574***	15.5	1495.7	0.963***
	(4.500)	(1.917)	(11.500)	(0.038)	(0.036)	(31.490)	(48.87)	(5.310)	(0.115)			(0.011)
$\tau \approx 240$	−11.140	3.061**	−42.600*	0.871***	0.112***	129.590**	137.51	−11.450	1.459***	9.3	1328.9	0.968***
	(9.53)	(1.605)	(23.200)	(0.041)	(0.033)	(70.100)	(93.12)	(8.110)	(0.088)			(0.010)

The following GARCH–M models are estimated:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1}$$
$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1}$$

The time series is from January 1961 to December 2009 with 588 observations. These regression models estimate the relation between the excess return ($R_{\tau,t+1} - R_{f,t}$) and its conditional variance, where the conditioning variables include the beginning of period monthly return on the 1-month T-Bill ($R_{f,t}$), the beginning of period yield spread ($Y_{\tau,t} - R_{f,t}$), and the one-month lag of excess return ($R_{\tau,t} - R_{f,t-1}$). The conditional distribution for the error term is the generalized error distribution (GED) to address non-normality of the errors, where the GED parameter (k) is the kurtosis parameter that accommodates fat tails. The GED nests the normal distribution and becomes the normal if $k = 2$. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Log-L is the value of the log likelihood function. AR(1) is the first order autoregressive coefficient for the fitted values of $\sigma^2_{\tau,t+1}$. Standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05 and 0.10 levels, respectively. The regression and GED parameters are two-tailed tests. The LM-ARCH is a one-tail test.

heteroskedasticity, but does not account for autocorrelation in the errors. Single-equation estimation accounts for heteroskedasticity and autocorrelation of unknown form, but not the cross-equation correlations in the error terms. Results for 3SLS are similar, but slightly weaker than GMM estimation. Results for single-equation estimation are substantially weaker than both 3SLS and GMM estimation. Thus, accounting for the cross-equation correlations in the errors produces efficiency gains that have an important impact on the statistical significance of the estimated relation between bond risk and return.

6.5. Discussion of implications for asset pricing models

Our findings have implications for the modeling of investor preferences and asset returns that support the conclusions of Cochrane (2001, 2006). Our finding of a positive relation between the first two moments of bond returns is evidence that bond realized returns tend to be high during good times of low marginal utility and low during bad times of high marginal utility. The inverse relation between a fixed income security's price and discount rate, implies the opposite relation for expected bond returns and marginal utility. Thus, a challenge for asset-pricing models is to capture the fact that investors associate periods of high expected (low realized) bond returns with bad times. A well known result from the prediction literature is that expected returns on stocks and bonds are higher near the troughs of recessions than at the peaks.[19] Thus, our results support Cochrane's conclusion that theoretical models need to explain, and empirical models need to capture, the fact that investors fear recessions.

The existing ICAPM specializations of the consumption-based model are ill-suited to explain our results.[20] The ICAPM approach assumes that the marginal utility of consumption is a function only of wealth and state variables that describe the conditional distribution of expected future returns. Unless the coefficient of relative risk aversion is very low (less than one), the ICAPM associates good times with high, and bad times with low, expected returns.[21] If one believes that risk aversion is reasonably high, our results support the conclusion that investor preferences are not adequately modeled by wealth and investment opportunities alone.

Our results are consistent with Cochrane's (2001, 2006) conclusion that asset pricing models must capture the fact that investors are concerned not only with the wealth effects of holding assets, but of the fact that assets do poorly at particular times or in particular states of nature (recessions). Cochrane suggests that this can be done in a utility framework by adding arguments into the utility function that enter nonseparably either over time or over states of nature. For example, Campbell and Cochrane (1999) associate high expected returns with bad times by adding an argument, habit, that enters the utility function nonseparably over time. For the ICAPM framework, Cochrane recommends adding a recession state variable to the value function.

7. Stability of the risk–return relation

The regression models reported in Tables 3–5 assume a time invariant linear relation between the expected excess return and conditional variance. The theoretical model of Section II does not restrict

[19] Fama and French (1989) find that risk premiums on stocks and long-term corporate bonds are related to variables that track business conditions. They conclude that excess returns are high when economic conditions are weak and low when economic conditions are strong. Pilotte and Sterbenz (2006) report similar findings for Treasury bonds and stocks. They find that conditional mean excess returns on Treasury bond portfolios of maturities of one to five years peak near the troughs of recessions, while conditional means of shorter maturity bonds and bills peak during recessions prior to the trough (see their Table 5).

[20] Two excellent sources of discussion of the relation of the ICAPM to the general model are Cochrane (2006, 2007).

[21] The coefficient of relative risk aversion determines whether investors will increase or decrease consumption in response to changes in expected future returns. When risk aversion is greater than one, investors increase both current and planned future consumption in response to an increase in expected returns. When risk aversion is less than one, investors are more aggressive in seeking growth in planned consumption. In response to an increase in expected returns, they decrease current consumption to invest more in risky assets.

the risk–return relation to a stable linear relation. In this section, we evaluate the linearity and stability of the relation between bond risk and return.

7.1. Analysis of excess return model residuals

A straightforward way to check the linear restriction for any of our models is to examine the relation between the regression error and financial conditioning information. If conditioning information explains variability in excess returns that is not related to conditional volatility, a linear relation between the conditional mean and conditional variance is rejected. Such a finding suggests that the reward to volatility changes over time.

Table 6 reports the results of OLS regressions of residuals from our models on financial conditioning information. For all three models, conditioning variables have explanatory power beyond that of the conditional variance. The explanatory power is greatest for the model where the conditional variance is based only on financial conditioning information. The explanatory power is lower in models where the conditional variance estimates incorporate GARCH effects. At least one conditioning variable is significant in most of the residual regressions. Clearly, the conditioning variables capture variation in excess returns that is not related to our estimates of the conditional variance. A time invariant linear specification of the relation between the conditional mean and conditional volatility is rejected, which suggests that the reward to volatility changes over time.[22,23]

7.2. Rolling correlations between conditional means and conditional variances

To provide evidence on the impact of changing reward to volatility on the stability of the risk–return relation we examine the relation between estimates of the conditional mean and conditional variance. We calculate contemporaneous correlations between estimates of conditional means and conditional variances for each bond maturity over 17-month rolling periods.[24]

To get a time series of fitted values, we estimate final models of conditional means and variances for Treasury Bond excess returns. Our final model incorporates all aspects of our prior models. The conditional mean is modeled as a function of both the conditional variance and financial conditioning information. The conditional variance incorporates both GARCH effects and financial conditioning information. We first estimate the following GARCH-M model:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \alpha_{\tau,2}(Y_{\tau,t} - R_{f,t}) + \alpha_{\tau,3}(R_{\tau,t} - R_{f,t-1}) + \gamma_{\tau,t+1} \tag{16}$$

$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1} \tag{17}$$

After the initial estimation, we drop explanatory variables that are not significant at the 0.10 level and re-estimate the model. The final models with only variables that are statistically significant in explaining the conditional mean or conditional variance are reported in Table 7.

An interesting aspect of Table 7 is that the GARCH in mean term is significant for only two bond maturities. Results of omitted variable tests (not reported) confirm this conclusion. The effect of the conditional variance on the conditional mean is generally subsumed by the financial conditioning information. The yield spread is always significant in explaining the excess return and the lagged excess return is significant in explaining the excess return for all but the 240-month bond. In the variance equation, the GARCH terms and the one-month rate are always significant in explaining the

[22] Pilotte and Sterbenz (2006) find that Sharpe ratios on long-term bonds, but not short-term bonds, vary over the business cycle. Our results differ in indicating that there is time variation in the reward to volatility for all bond maturities. A potential explanation for the difference in results is that our tests are not tied to the business cycle.

[23] The results for bonds reported in Table 7 are consistent with results that Harvey (2001) reports for stocks. Harvey finds that the rejection of a linear risk-return relation for stocks is robust to changes in the method used to estimate the conditional variance. He also presents graphic evidence that the ratio of conditional mean to conditional volatility for stocks has a distinct business cycle pattern.

[24] In his examination of the stability of the risk-return relation for common stocks, Whitelaw (1994) chooses a 17-month window to balance the need for reasonably accurate estimates with the need for a period that is short enough to pick up variation over the length of a business cycle. We follow his approach to facilitate a comparison with existing results for stocks.

Table 6
Analysis of residuals from models of the bond risk-return relation.

Maturity	Residuals from risk-return model with conditional volatility estimates based on financial conditioning information				Residuals from risk-return model with conditional volatility estimates based on Simple GARCH-M model				Residuals from risk-return model with conditional volatility estimates based on GARCH-M with financial conditioning information in the variance equation			
	Constant ($\times 10^4$)	$Y_{\tau,t}-R_{f,t}$	$R_\tau - R_{f,t-1}$	R^2	Constant ($\times 10^4$)	$Y_{\tau,t}-R_{f,t}$	$R_\tau - R_{f,t-1}$	R^2	Constant ($\times 10^4$)	$Y_{\tau,t}-R_{f,t}$	$R_\tau - R_{f,t-1}$	R^2
$\tau \approx 3$	−2.720***	0.686***	0.082	0.12	−1.260***	0.653***	0.089	0.10	−1.090**	0.582***	0.052	0.06
	(0.382)	(0.144)	(0.078)		(0.471)	(0.218)	(0.064)		(0.481)	(0.199)	(0.063)	
$0 < \tau \le 12$	6.640***	−1.261***	0.167**	0.16	9.090***	−1.559***	0.153***	0.19	8.950***	−1.570***	0.152**	0.19
	(2.040)	(0.356)	(0.079)		(0.280)	(0.464)	(0.066)		(1.380)	(0.145)	(0.067)	
$12 < \tau \le 24$	14.910***	−2.180***	0.177***	0.11	19.290***	−2.574***	0.164***	0.12	19.180***	−2.613***	0.162***	0.13
	(5.210)	(0.675)	(0.054)		(7.040)	(0.864)	(0.046)		(7.070)	(0.863)	(0.046)	
$24 < \tau \le 36$	20.090**	−2.450***	0.141***	0.07	26.680**	−2.878***	0.135***	0.08	26.330**	−2.924***	0.132***	0.08
	(8.030)	(0.834)	(0.048)		(10.470)	(1.050)	(0.042)		(10.500)	(1.048)	(0.041)	
$36 < \tau \le 48$	20.110**	−2.258***	0.134***	0.05	25.470**	−2.594***	0.131***	0.06	26.320**	−2.592***	0.133***	0.06
	(9.690)	(0.850)	(0.045)		(11.200)	(0.968)	(0.043)		(11.330)	(0.970)	(0.043)	
$48 < \tau \le 60$	22.450*	−2.218**	0.135***	0.04	28.070**	−2.443**	0.129***	0.04	28.240**	−2.418**	0.131***	0.04
	(12.590)	(0.997)	(0.042)		(13.000)	(1.023)	(0.040)		(13.100)	(1.023)	(0.040)	
$\tau \approx 120$	17.310	−1.811*	0.056	0.01	26.550*	−2.056***	0.060	0.01	28.950*	−2.002***	0.063	0.01
	(14.190)	(0.937)	(0.038)		(15.170)	(1.008)	(0.039)		(15.310)	(10.14)	(0.039)	
$\tau \approx 240$	8.510	−0.750	0.038	0.00	14.250	−1.180	0.035	0.00	16.030	−1.147	0.037	0.00
	(19.130)	(1.130)	(0.044)		(19.250)	(1.160)	(0.044)		(19.280)	(1.154)	(0.044)	

Residuals are from the excess return regressions reported in Tables 3–5, where the conditional volatility is modeled using financial conditioning information in Table 3 a simple GARCH-M model in Table 4 and a GARCH-M model with financial conditioning information included in the conditional variance equation in Table 5 The residuals from each model of the risk-return relation are regressed on the beginning-of-period yield spread ($Y_{\tau,t} - R_{f,t}$), and, the one-month lag of the excess return ($R_{\tau,t} - R_{f,t-1}$). Results are for OLS estimation with Newey–West autocorrelation and heteroskedasticity consistent standard errors reported in parentheses. ***, **, * denote significance at the 0.01, 0.05, and 0.10 levels, respectively.

Table 7
Final models of conditional means and conditional variances for Treasury Bond returns.

Maturity	Mean equation				Variance equation					GED Parameter	LM-ARCH	Log-L	AR(1) coefficient for $\sigma^2_{\tau,t+1}$
	Constant ($\times 10^4$)	$\sigma^2_{\tau,t+1}$	$Y_{\tau,t}-R_{f,t}$	$R_\tau - R_{f,t-1}$	Constant ($\times 10^6$)	$\sigma^2_{\tau,t+1}$	$\varepsilon^2_{\tau,t-1}$	$R_{f,t}$ ($\times 10^4$)	$R_\tau - R_{f,t-1}$ ($\times 10^4$)				
$\tau \approx 3$	1.070***	223.91***	0.298***	0.192***	0.003	0.832***	0.131***	0.081***	0.401**	1.139***	15.6	3607.3	0.965***
	(0.188)	(60.45)	(0.071)	(0.040)	(0.002)	(0.026)	(0.031)	(0.013)	(0.172)	(0.094)			(0.011)
$0 < \tau \le 12$	0.007	42.240***	0.447***	0.200***	0.034	0.812***	0.163***	0.390***		1.408***	14.9	2943.0	0.954***
	(0.784)	(16.17)	(0.103)	(0.042)	(0.029)	(0.035)	(0.036)	(0.140)		(0.124)			(0.012)
$12 < \tau \le 24$	−2.780		1.0281***	0.204***	−0.618***	0.889***	0.096***	3.150***		1.361***	29.1***	2313.5	0.971***
	(2.310)		(0.254)	(0.041)	(0.229)	(0.024)	(0.024)	(0.784)		(0.112)			(0.010)
$24 < \tau \le 36$	−6.470*		1.582***	0.158***	−2.270***	0.897***	0.094***	9.340***		1.348***	17.6	2031.4	0.974***
	(3.530)		(0.359)	(0.040)	(0.487)	(0.022)	(0.024)	(1.850)		(0.110)			(0.009)
$36 < \tau \le 48$	−9.900**		1.825***	0.131***	−4.680***	0.889***	0.100***	18.770***		1.435***	11.3	1868.7	0.978***
	(4.620)		(0.438)	(0.040)	(0.855)	(0.024)	(0.026)	(3.330)		(0.125)			(0.009)
$48 < \tau \le 60$	−14.900***		2.002***	0.138***	−7.910***	0.895***	0.094***	30.070***		1.375***	16.3	1763.0	0.980***
	(4.950)		(0.475)	(0.039)	(1.490)	(0.023)	(0.026)	(5.470)		(0.117)			(0.008)
$\tau \approx 120$	−17.790***		2.021***	0.097**	−12.400***	0.882***	0.125***	45.080***	−7.260*	1.551***	14.8	1501.1	0.973***
	(6.460)		(0.611)	(0.039)	(3.21)	(0.025)	(0.028)	(13.370)	(4.390)	(0.118)			(0.009)
$\tau \approx 240$	−30.650***		3.447***		−17.600**	0.893***	0.109***	70.520***		1.392***	10.1	1334.5	0.970***
	(10.620)		(0.734)		(6.920)	0.027	0.030	(26.530)		(0.091)			(0.010)

The initial estimated models are:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \alpha_{\tau,2}(Y_{\tau,t} - R_{f,t-1}) + \alpha_{\tau,3}(R_{\tau,t} - R_{f,t-1}) + \gamma_{\tau,t+1}$$
$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1}$$

The time series is from January 1961 to December 2009 with 588 observations. The insignificant explanatory variables were dropped to obtain the final estimated models reported below. The initial regression models include the conditional variance in the mean equation, and the mean and variance equations initially includes the beginning of period yield spread ($Y_{\tau,t} - R_{f,t}$), and the one-month lag of excess return ($R_{\tau,t} - R_{f,t-1}$) as conditioning variables. The conditional variance also includes the beginning of period monthly return on the 1-month T-Bill ($R_{f,t}$). The conditional distribution for the error term for the estimations is the generalized error distribution (GED) to address non-normality of the errors. The GED parameter (k) is the kurtosis parameter that accommodates fat tails and becomes the normal distribution if $k = 2$. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Log-L is the value of the log likelihood function. AR(1) is the first order coefficient for the fitted values of $\sigma^2_{\tau,t+1}$. Standard errors are in parentheses. ***, **, *denote significance at the 0.01, 0.05, and 0.10 levels, respectively. The regression and GED parameters are two-tailed tests. The LM-ARCH is a one-tail test.

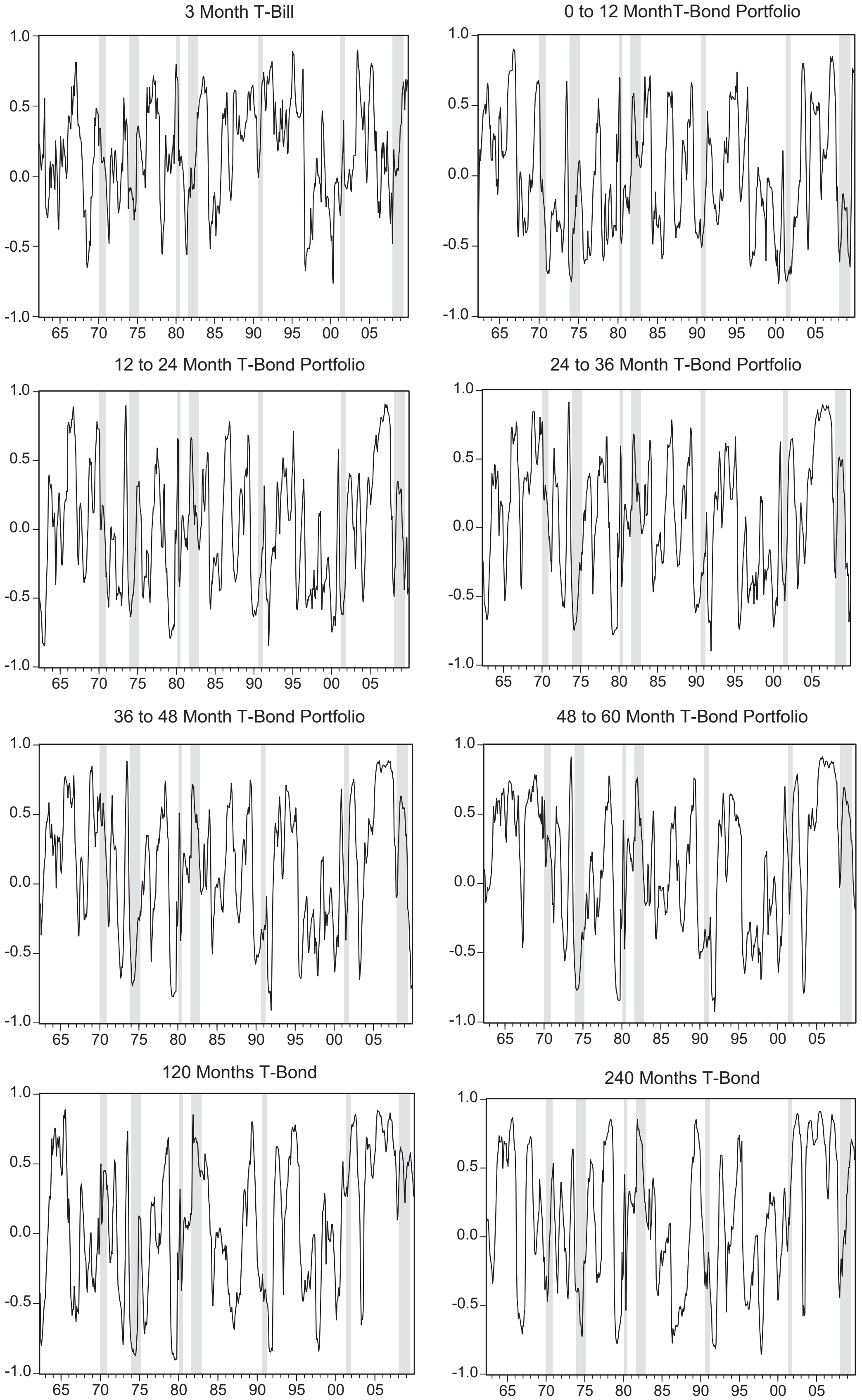
3 Month T-Bill
0 to 12 MonthT-Bond Portfolio
12 to 24 Month T-Bond Portfolio
24 to 36 Month T-Bond Portfolio
36 to 48 Month T-Bond Portfolio
48 to 60 Month T-Bond Portfolio
120 Months T-Bond
240 Months T-Bond
1.0
0.5
0.0
-0.5
-1.0
65 70 75 80 85 90 95 00 05

Table 8
Correlation matrix of rolling estimates of correlations between the conditional moments of bond excess returns.

Maturity	$\tau \approx 3$	$0 < \tau \leq 12$	$12 < \tau \leq 24$	$24 < \tau \leq 36$	$36 < \tau \leq 48$	$48 < \tau \leq 60$	$\tau \approx 120$	$\tau \approx 240$
$\tau \approx 3$	1.00							
$0 < \tau \leq 12$	0.47	1.00						
$12 < \tau \leq 24$	0.26	0.70	1.00					
$24 < \tau \leq 36$	0.12	0.50	0.89	1.00				
$36 < \tau \leq 48$	0.03	0.44	0.79	0.91	1.00			
$48 < \tau \leq 60$	−0.02	0.35	0.70	0.87	0.93	1.00		
$\tau \approx 120$	0.11	0.22	0.46	0.55	0.67	0.74	1.00	
$\tau \approx 240$	0.03	0.13	0.31	0.47	0.54	0.67	0.79	1.00

The following are correlations between rolling estimates of correlations between the fitted values of the conditional mean and conditional variance of excess returns on bonds of different maturities. The 17-month rolling correlation for each bond maturity is between the conditional excess return and conditional variance as shown in Fig. 1. The model used to estimate the conditional excess returns and variances is shown in Table 7 for each maturity. Using all of the time series from January 1961 to December 2009, the correlation coefficients begin in May 1962 and end in December 2009.

conditional volatility. The yield spread is never significant in the variance equation and the lagged excess return is significant only for the 3-month bill and 120 month bond. Viewed overall, the results reported in Table 7 indicate that the yield spread and lagged excess return are generally important in predicting conditional means, while the one-month rate and GARCH effects are important in predicting the conditional variances.

Fig. 1 presents graphs of the rolling estimates of correlations between the fitted series of conditional excess returns and conditional variances for each bond maturity. The graphs show substantial variation over time in the short-term relation between bond risk and return. For longer maturities, both the range of correlations and incidence of negative correlations are similar to those reported by Whitelaw (1994) for stocks. For the shortest maturities, the range of correlations is diminished somewhat, but there remains substantial variation over time and numerous negative correlations.

The graphs in Fig. 1 are shaded to show business cycle expansions and contractions. The correlations vary substantially within both expansions and contractions. The graphs show no obvious business cycle pattern in the relation between bond risk and return, though there appears to be some tendency for the estimated relation to decrease either prior to or early in recessions. Our ability to draw firm conclusions regarding business cycle patterns is limited by the fact that our sample contains only seven measured contractions.

To illustrate the co-movement in the risk–return relation across bond maturities, in Table 8 we report correlations between the rolling correlations of each maturity pair. The correlations in Table 8 indicate that time variation in the risk–return relation is similar for adjacent maturities, but differs substantially when the difference in maturity is large. Nevertheless, correlations are positive for all but one pair of bond maturities.

Overall, our examination of rolling correlations shows instability in the short-term relation between bond risk and return. The relation is often negative for each bond maturity. For longer maturities, both the range of correlations and incidence of negative correlations are similar to those reported previously for common stocks. For shorter maturities the range is diminished somewhat; however, the rolling correlations for all bond maturities do tend to move together. Negative rolling correlations suggest there may be specific time periods in which bonds were effective hedging assets. Further study is required to draw any definitive conclusions regarding this possibility.

Fig. 1. Rolling estimates of correlations between the conditional moments of bond excess returns The graphs above plot the 17-month rolling estimates of the correlation between the fitted values of the conditional mean excess return and conditional variance for each bond maturity. The models used to predict the excess returns and variances are reported in Table 7. Using all of the time series from January 1961 to December 2009, the correlation coefficients begin in May 1962 and end in December 2009. Shaded areas represent business cycle contractions as defined by the National Bureau of Economic Research with the beginning month defined as the first trough month and the ending month defined as the last trough month. Non-shaded areas are business cycle expansions.

8. Conclusions

Our full sample estimation of the linear relation between the conditional mean and conditional volatility of U.S. Treasury Bonds documents a significant positive relation between bond risk and return for maturities of 3 months to 20 years. This finding is not very sensitive to the method used to estimate conditional volatility and is especially reliable for bond maturities of 5 years or less. A positive, rather than negative, risk–return relation indicates that Treasury Bonds are not a hedging asset as that concept is defined in consumption-based models of intertemporal choice. Rather, an effective hedging asset has the return characteristics of a short position in Treasury Bonds. Short positions on shorter-maturity bonds appear to be the most statistically reliable means for an investor to hedge the marginal utility of consumption.

Our full sample results are consistent with the conclusion that realized returns on Treasury Bonds are high when investors least value, and low when investors most value, the benefits of an additional dollar of consumption. Thus, for a special case of the consumption-based model to accurately reflect investor preferences, it must explain why investors associate bad times of high marginal utility with periods of low realized and high expected bond returns. Special cases that assume that the marginal utility of consumption is a function of at most wealth and investment opportunities, such as the ICAPM specializations of Merton (1973) and Campbell (1993), do not do so. Unless one assumes that risk aversion is very low, those models associate bad times with low expected returns. Explaining why investors associate bad times with high expected returns requires a model that captures the fact that investors are concerned not only with the wealth effects of holding assets, but with the fact that assets do poorly at particular times or in particular states of nature (recessions). Campbell and Cochrane (1999) do so by adding an argument to the utility function, habit that enters nonseparably over time.

Our analysis of the linearity and stability of the risk–return relation produces evidence that the reward to volatility and the short-term relation between bond risk and return may vary over time. The fact that rolling correlations between estimates of the conditional mean and conditional volatility are often negative suggests that there may be specific time periods in which bonds were effective hedging assets. Further study is required to draw any definitive conclusions regarding this possibility.

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Empirical analysis of the generalized consumption asset pricing model: Estimating the cost of capital

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ABSTRACT

Other than the problematic discounted cash flow and capital asset pricing models that have been used for decades, no other asset pricing models have generally been adopted for estimating the cost of common equity capital. A recently developed and promising general consumption asset pricing model for estimating costs of common equity is successful in empirical tests and applied for estimating the cost of common equity. This research presents an empirical investigation of the model for application to the regulation of public utilities and stock market and compares the cost of capital results with the CAPM. The model is applicable for estimating the cost of common equity capital for any stock. The paper recommends that the GCAPM be considered as an additional asset model with the others that are typically used as additional information in estimating the cost of common equity capital.

1. Introduction

The state of cost of common equity estimation and modeling has become stale. The only asset pricing models typically used by firms for estimating their cost of common equity are mainly the

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capital asset pricing model (CAPM) with a few firms using the dividend discount cash flow (DCF) and the arbitrage pricing (APM) models, all of which were developed in the 60s and 70s. A survey conducted by the Association for Financial Professionals (2011) on the use of asset pricing models for estimating the cost of capital found that 87% of all firms and 91% of publicly traded firms use the CAPM, 3% of all firms and 2% of publicly traded firms use the DCF model and 1% for both types use the APM. Whereas most firms and much academic research[1] still use the CAPM for cost of capital estimations, the literature on the problems with the empirical evaluation and theoretical foundations of the CAPM is vast and conclusively negative. Fama and French (2004) summarize the literature and conclude that "...In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid." This paper does not recommend that the CAPM be discarded or substituted with the GCAPM discussed and tested in this paper. No information should be ignored for estimating the cost of common equity.

Michelfelder and Pilotte (2011) introduced a new asset pricing model for estimating the cost of common equity capital based on the intertemporal asset pricing model literature (discussed below). The generalized consumption asset pricing model requires a minimum of assumptions in its theoretical development. It also is applied with a minimum of subjectivity. Ahern, Hanley, and Michelfelder (2011) performed some cursory preliminary empirical tests and applied the GCAPM to model the risk–return relationship for stocks and estimate the cost of common equity. They used a few public utility stocks to estimate and apply the GCAPM. Public utility applications are important as public utilities are regulated primarily by the allowed rate of return which is supposed to reflect the cost of capital. It is so important to the public utility industries that the initial academic literature on cost of capital estimation and application was based to a major extent on public utility industry studies. See references in Morin (2006).

Ahern et al. (2011) found the GCAPM to be promising in cursory empirical testing and in generating reasonable, mechanically (without subjective judgment) developed estimates of the cost of common equity capital for a small sample of public utilities, consisting of a few electric, electric and gas, natural gas, and water utilities.

Although the model can be used for estimating the cost of capital for any firm, this investigation also focuses on public utility regulation and applications since it is likely to be the most contested issue in a public utility rate proceeding (see Bonbright, Danielsen, & Kamerschen, 1988; McDermott, 2012; Phillips, 1993).[2] Additionally, the practice of public utility regulation has not adopted other models other than DCF and the CAPM (Ahern et al., 2011). These models have numerous strong assumptions and require many subjective judgments in application that leads to highly contested rate of return recommendations in public utility proceedings. The application of these models is highly questionable and the estimates subject to many vagaries due to choices of inputs.

This paper performs an empirical investigation of the GCAPM for public utility cost of common equity estimation.

2. The model

The literature on the traditional CAPM and consumption asset pricing models is vast so that literature is briefly discussed that summarizes the work leading to the model used in this research.

The GCAPM has been recently derived and empirically tested for US Treasury Bonds and Bills and stock market returns in Michelfelder and Pilotte (2011) and preliminarily applied and tested for public

[1] A recent variant of the DCF model has emerged in the academic literature for estimating the cost of common equity capital for other research, the implicit cost of capital. It is essentially the expected book value of a firm plus the capitalized value of the infinite stream of the conditionally expected net income minus the required net income to earn its cost of capital equated to the current stock price. The capitalization rate is the cost of common equity and the same rate implied in the required net income. See Pastor, Sinha, and Swaminathan (2008) and Molina-Ortiz and Phillips (2014).

[2] McDermott (2012) on pp.13–14 states: "While determining the operating costs and rate base is not without controversy, the calculation of the firm's cost of capital is generally one of the most contentious issues in a rate case...." The cost of equity is an expectation held by the "marketplace" and is therefore not directly observable. As a result it must be estimated and the question of what is a correct assessment of the market's true value is partly what makes this issue so contentious.

utility stocks and stock markets in Ahern et al. (2011). There are many restrictive versions of the model that led to the derivation of the GCAPM. The main asset pricing models used as foundations to develop the GCAPM include the intertemporal capital asset pricing model in Merton (1973), models in Cochrane (2004), the intertemporal asset pricing model of Campbell (1993), and the habit-persistence model of Campbell and Cochrane (1999).

Some GCAPM highlights are that it (1) makes no assumptions about the efficiency of the asset market, (2) has no constraints on the investor's degree of risk aversion or limits on the magnitude of coefficient of risk aversion, (3) prices the risk that the investor is actually exposed to rather than the nonrealistic systematic risk that assumes that the investor has diversified away all nonsystematic risk. That is, the GCAPM does not assume that the investor has a perfectly diversified portfolio that eliminates all unique risk. The GCAPM even allows for the possibility of a negative relation between return and volatility where other asset pricing models do not. Investors are willing to pay (give up return or accept returns less than the risk free rate) to be exposed to patterns of volatility that hedge against downturns in business cycle levels of consumption. This property will be discussed below and considered in the empirical analysis.

Michelfelder and Pilotte (2011) specify the GCAPM as the *ex ante* risk premium of an asset i as a function of the volatility of the asset i *ex ante* return:

$$E_t\left[R_{i,t+1}\right] - R_{f,t} = -\frac{vol_t\left[M_{t+1}\right]}{E_t\left[M_{t+1}\right]} vol_t\left[R_{i,t+1}\right] corr_t\left[M_{t+1}, R_{i,t+1}\right], \tag{1}$$

where $R_{i,t+1}$ is the *ex ante* return on asset i, $R_{f,t}$ is the risk free rate of return at time t, M_{t+1} is the stochastic discount factor (SDF), vol_t is the volatility of the variable conditioned on information available in time t, E_t is the expectations operator conditional on information available in time t, and, $corr_t$ is the correlation conditioned on information available in time t. The SDF is the intertemporal marginal rate of substitution in consumption:

$$M_{t+1} = \left(\frac{1}{1+k}\right)\frac{U_{c,t+1}}{U_{c,t}}, \tag{2}$$

where the U_c's are the marginal utilities of consumption for the differing time periods and k is the discount rate for the period from t to $t+1$. The ratio of the marginal utilities of consumption for two time periods, $U_{c,t+1}/U_{c,t}$, rises if the expected future dollar value of consumption falls below current consumption. This property is due to the concave shape of the investor's utility function and diminishing marginal utility and generates the specification of the model to identify the business cycle (represented by consumption expenditures) hedging property (if any) of an asset.

The ratio, $vol_t\left[M_{t+1}\right]/E_t\left[M_{t+1}\right]$, is the slope of the mean-variance frontier and reflects the expected volatility of utility from consumption relative to expected utility, which is the conditional coefficient of variation in utility. If conditional volatility rises relative to expected value, investors require a greater risk premium as compensation. The algebraic sign of the relation (slope) between the expected risk premium and its conditional volatility is determined by the conditional correlation ($corr_t$) of the expected risk premium and the SDF. The sign of this slope has the opposite sign of the correlation of the asset return and the ratio of intertemporal marginal utilities in consumption. When the correlation is positive (negative), the asset will have a negative (positive) relation with its risk. Since a decline in consumption in an economy is a component of a business cycle contraction, assuming investors have a concave utility function of consumption, a decline in expected consumption increases marginal utility as the investor's consumption moves left on the utility function. The hedging asset generates positive changes in asset returns when the business cycle is in a contraction and therefore the asset is a business cycle and consumption hedge.

Therefore, if the estimated return/risk coefficient is negative, the asset is a business cycle/consumption hedge. Under these circumstances, it is conceivable that an investor may accept a return less than the risk-free rate as she is willing to pay (give up return) to be exposed to this specific pattern of higher volatility. This asset delivers rising returns when the investor needs it most – during a business cycle downturn. A hedging asset pays more during business cycle contractions and less during expansions and therefore plays the role of insurance, paying to avoid hardship.

The slope of the relation between the return and risk is very rich in insight and structure. The slope of the return and volatility relationship is a function of the volatility of the return, the independent variable. As the volatility changes, it affects the $corr_t$ as correlation equals covariance of the two variables divided by the product of the volatility of the two variables.

3. The data

The company stocks in the rate of return regulated electric, electric and gas distribution (combination), natural gas distribution (sometimes referred to as local distribution companies or "LDC's"), and water utility industries are defined by the AUS Utility Reports©,[3] a national public utilities financial consulting firm and database company established in 1968 (www.aus.com). These include all 77 public utility stocks that are publicly traded in the US. The monthly stock total returns for each public utility begin with the first available monthly data observation for each individual utility company stock in the University of Chicago's Booth School of Business Center for Research in Security Prices (CRSP®) database. The data available from CRSP® begins no earlier than January 1926 for stock data in general and ends for this study at December 2011. CRSP® faculty and staff determine how far back to go to obtain accurate stock price and returns data on every stock. Monthly returns observations range from the earliest available date in CRSP® for each stock to December 2011. The risk free rate is the monthly long-term US Treasury bond yields from Morningstar (2012). The US stock market data is the CRSP® Fama–French monthly returns risk premium based on the CRSP® value-weighted stock market index that includes most stocks on the NYSE, NASDAQ, and AMEX and includes approximately 11,000 stocks. This data is publicly available at no cost from Professor Kenneth French's data website (French, 2012).

Table 1 shows descriptive statistics for the monthly risk premium data for each stock and the data observation range for each stock by industry. The annualized compound annual return premia based on the monthly means range from approximately 5% to 7.5%. Standard deviations are about 10–20 times the mean risk premiums (coefficients of variation).

The greatest number of observations are obtained for each stock as more data history capture a longer period of the fundamental nature of asset pricing volatility clustering patterns, whether the patterns are recent or many years old. The nature of autoregressive conditional heteroskedasticity (ARCH) models is based on the fundamental nature of financial markets volatility clustering patterns.

4. Empirical results

An obvious method to estimate Eq. (1), the relation between risk and return, is the generalized autoregressive conditional heteroskedasticity in mean (GARCH-M) model. The GARCH-M model was developed specifically for estimating asset return and volatility relations. GARCH-M is used since it specifies the conditional expected risk premium as a linear function of its conditional volatility, which is the theoretical specification of Eq. (1). Due to the high likelihood of ARCH effects in asset returns the use of GARCH methods will improve the efficiency of the estimates if ARCH effects should be present in the data. The GARCH-M model adopted herein was initially developed and tested by Engle, Lilein, and Robins (1987) to estimate the relationship between US Treasury and corporate bond risk premiums and their expected volatilities. The GARCH-M model is specified (without an intercept in the return equation) as:

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma^2_{i,t+1} + \varepsilon_{i,t+1}, \tag{3}$$

$$\sigma^2_{i,t+1} = \beta_0 + \beta_1\sigma^2_{i,t} + \beta_2\varepsilon^2_{i,t} + \eta_{i,t+1}, \tag{4}$$

where $R_{i,t+1}$ is the expected total return on asset i, $R_{f,t}$ is the risk-free rate of return, ${\sigma^2}_{i,t+1}$ is the conditional or predicted variance of the risk premium for asset i that is conditioned on past information,

[3] AUS, Inc. is a holding company of financial consulting, database and marketing research consulting firms. AUS Consultants is a national public utilities financial consulting firm established in 1968. See www.ausconsultants.com.

Table 1
Descriptive statistics by utility industry.

Electric stock Symbols	Monthly mean RP	Std. dev.	Begin period	
AEE	0.00319	0.04812	January	1953
AVA	0.00380	0.06352	October	1952
BKH	0.00701	0.06850	January	1973
CHG	0.00375	0.04869	December	1945
CMS	0.00250	0.07378	March	1947
CNP	0.00609	0.06924	September	1943
CPK	0.00646	0.05888	January	1973
D	0.00660	0.05021	July	1983
DTE	0.00433	0.05509	January	1926
DUK	0.00374	0.05750	August	1961
ED	0.00566	0.06678	January	1926
EDE	0.00445	0.04824	November	1946
ETR	0.00537	0.06362	June	1949
EXC	0.00477	0.05263	August	1943
LNT	0.00462	0.05212	January	1973
MDU	0.00623	0.06120	October	1948
MGEE	0.00499	0.04921	January	1973
NI	0.00245	0.06306	January	1963
NU	0.00287	0.05700	March	1967
NVE	0.00303	0.07535	December	1962
OGE	0.00562	0.05579	October	1950
PCG	0.00508	0.06478	January	1926
PEG	0.00486	0.05421	April	1948
POM	0.00406	0.05045	January	1947
PPL	0.00474	0.05408	January	1946
SCG	0.00589	0.05684	December	1946
SRE	0.00510	0.06067	July	1998
TE	0.00320	0.06615	August	1962
TEG	0.00476	0.04736	June	1953
UGI	0.00527	0.06988	July	1929
UIL	0.00470	0.06512	January	1972
UNS	0.00020	0.08707	June	1969
UTL	0.00479	0.05157	April	1985
VVC	0.00544	0.05821	January	1971
WEC	0.00562	0.04747	December	1947
WR	0.00439	0.05186	August	1949
XEL	0.00513	0.05463	March	1949
Mean	0.00461	0.05889		

Electric stock symbols	Mean RP	Std. dev.	Begin period		Gas stock symbols	Mean RP	Std. dev.	Begin period	
ALE	0.00541	0.53263	April	1950	AGL	0.00592	0.05085	January	1973
AEP	0.00429	0.05421	October	1949	ATO	0.00608	0.06014	January	1984
CNL	0.00707	0.05232	December	1981	DGAS	0.00460	0.04618	May	1981
EIX	0.00559	0.06519	June	1926	EGN	0.00709	0.06478	January	1958
EE	0.00799	0.06749	March	1996	EQT	0.00708	0.06400	July	1950
FE	0.00450	0.05336	October	1946	EGAS	0.00712	0.07676	February	1986
GXP	0.00406	0.05268	October	1950	LG	0.00382	0.08632	January	1926
HE	0.00327	0.05492	November	1964	NFG	0.00562	0.05605	August	1955
IDA	0.00451	0.05363	February	1944	NJR	0.00636	0.06099	January	1973
NEE	0.00671	0.05890	March	1950	NWN	0.00491	0.05826	January	1973
OTTR	0.00449	0.06278	January	1973	OKE	0.00761	0.07400	June	1954
PNM	0.00160	0.07506	October	1972	PNY	0.00630	0.05847	March	1970
PNW	0.00244	0.08241	September	1961	RGCO	0.00490	0.04263	March	1994
SO	0.00809	0.11648	November	1929	SJI	0.00544	0.05631	October	1958
					STR	0.00733	0.07784	February	1961
Mean	0.00500	0.09872			SWX	0.00396	0.06799	January	1973
					WGL	0.00513	0.05847	Feb	1940
					WMB	0.01230	0.13432	Aug	1962
					Mean	0.00620	0.06635		

Table 1 (*Continued*)

Water stock symbols	Mean RP	Std. dev.	Begin period	
ARTNA	0.00620	0.05574	June	1996
AWR	0.00527	0.06154	January	1973
CTWS	0.00488	0.05391	July	1975
CWT	0.00550	0.05655	January	1973
MSEX	0.00558	0.05235	January	1973
SJW	0.00620	0.06565	March	1972
WTR	0.01006	0.07025	August	1971
YORW	0.00912	0.07119	February	2001
Mean	0.00660	0.06090		

The mean RP is the mean of the monthly risk premium returns data for each stock used to estimate the GCAPM with the GARCH models. The mean is calculated from the beginning period and ending in December 2011.

and, $\varepsilon_{i,t}$ and $\eta_{i,t+1}$ are the error terms for the mean and volatility equations, respectively. The parameter, α_i, or "alpha" is the return-to-risk coefficient as specified in Eq. (1) as:

$$\alpha_{i,t} = -\frac{vol_t\,[M_{t+1}]}{E_t\,[M_{t+1}]} corr_t \left[M_{t+1}, R_{i,t+1}\right] \tag{5}$$

This parameter represents the relation between risk premium and volatility and its algebraic sign indicates whether the asset is a business cycle hedge. The parameter itself is a function of the independent variable, the conditional variance, and is time varying as the conditional standard deviation of the return is included in the conditional correlation, $corr_t[M_{t+1}, R_{i,\,t+1}]$, of the stochastic discount factor and the return. The theoretical model, Eq. (1), is specified without an intercept, therefore it is estimated the model without the intercept, but robustness tests are done to evaluate the model with intercepts. Intuitively the intercept should be zero. Otherwise would indicate evidence of an excess return premium or payment (if negative) that is not associated with volatility. The "no-intercept" specification has been found to be robust in producing consistently positive and significant relationships between common stock risk premiums and risk in GARCH-M models. These findings are discussed in Lanne and Saikkonen (2006) and Lanne and Luoto (2007).

Table 2a–d shows the GARCH model estimates for all publicly traded US electric, electric and gas, gas, and water company stocks as well as the US stock market for comparison. The list of utility stocks and their categorization in each industry are defined by AUS Utility Reports® (2012) that is available upon request. The AUS Utility Reports® tracks all US publicly traded electric, gas and water utility stocks. The results show that the model fits almost all of the public utility stock returns and the US stock market returns well as almost all estimated parameters are significant, generally at p-values of 0.01 or less, except for water company stocks that have some p values that are generally less than 0.10, especially for the alpha slope that is used to estimate the cost of capital. Generally, water utility stocks have substantially less stock returns data for modeling.

All but seven of the Lagrange Multiplier ARCH statistics (LM-ARCH), a test for ARCH effects in the residuals, are not significant, indicating that the GARCH-M model is effective at removing most of the ARCH effects from the regression residuals. The sum of the slopes in the variance equation ($\beta_1 + \beta_2$) is close to one for all stocks and the stock market. A value of one or greater indicates the presence of an integrated GARCH process (IGARCH) (Engle & Bollerslev, 1986). Shocks in returns that have an IGARCH process have a permanent effect on the conditional variance and therefore the asset's value.

The slopes on conditional variance, the alphas, are positive and significant for most of the utility stocks (all but seven) and the US stock market. Those that are not significant have alpha estimates that are in a reasonable range of values. These results are evidence that there is a long-term positive relation between risk and return and that none of the assets in this investigation are business cycle consumption hedges as none are negative in algebraic sign. Since utility sales, especially electricity usage and therefore cash flows are generally highly correlated with GDP, positive values were expected for the alpha estimates as utility stocks are not expected to be a business cycle hedge. Fig. 1 from the US Energy Information Administration's 2013 Annual Energy Outlook shows the close association between GDP and electricity use growth rates. As the energy intensity of GDP continues to decline

Table 2a
Electric utility stocks and US stock market GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
US Stocks (CRSP)	2.869***	0.000***	0.841***	0.128***	0.56
Electric utility stock symbols					
ALE	2.072***	0.000**	0.851***	0.094***	0.72
AEP	2.197***	0.000**	0.789***	0.112***	1.12
CNL	2.968***	0.000**	0.685***	0.180***	0.71
EIX	1.536***	0.000***	0.873***	0.108***	1.32
EE	1.853***	0.000	0.882***	0.090	1.14
FE	2.161***	0.000**	0.755***	0.158***	0.79
GXP	2.289***	0.000***	0.812***	0.149***	0.62
HE	1.634**	0.000***	0.786***	0.144***	0.88
IDA	1.981***	0.000**	0.851***	0.097***	0.93
NEE	2.166***	0.000**	0.871***	0.082***	0.74
OTTR	1.378**	0.001***	0.489***	0.248***	0.70
PNM	0.984	0.000***	0.834***	0.116***	0.52
PNW	1.142**	0.000***	0.639***	0.260***	2.03**
SO	0.944***	0.000**	0.894***	0.103***	0.57

The results are for all publicly traded electric utility stocks. The results are the GARCH-M regressions for the monthly risk premium on the asset ($R_{i,t+1} - R_{f,t}$) with conditional variance in the mean equation. The estimated model is:
$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma^2_{i,t+1} + \varepsilon_{i,t+1}$, where $\alpha_{i,t} = -(vol_t[M_{t+1}]/E_t\,[M_{t+1}])corr_t[M_{t+1}, R_{i,t+1}]$
$\sigma^2_{i,t+1} = \beta_0 + \beta_1\sigma^2_{i,t} + \beta_2\varepsilon^2_{i,t} + \eta_{i,t+1}$
The monthly data ranges from the earliest returns data available for each asset in the CRSP database (earliest returns data available is January 1926) and ends at December 2011. The return variable for US Stocks is the monthly risk premium on the value weighted CRSP stock returns from the Fama–French CRSP database. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals for 12 lags. It is χ^2 distributed with 12 degrees of freedom where the degrees of freedom are driven by the number of lags tested. Standard errors are in parentheses. ***, **, * denote p-values equal to less than 0.01, 0.05, and 0.10 levels, respectively, with two-tailed tests for regression coefficients and one-tailed test for LM-ARCH.

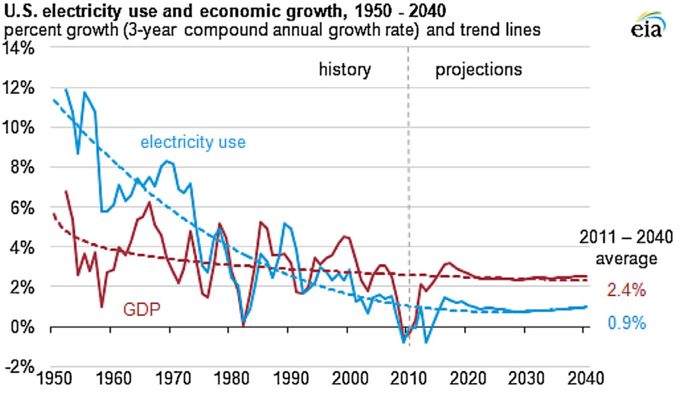

Fig. 1. Relation between GDP and electricity use.

due to the adoption of energy efficiency technologies, the growth rates of GDP and electricity use in recent years have started to moderately decouple and is expected to continue to do so.

Fig. 2 plots the average of the rolling estimated alpha for each utility industry group for each month from January 2006 to December 2011 to review the stability and trends in the alphas. Although not shown for each stock, the alphas range in value from about 0.5 to almost 3.0 and are relatively stable across all stocks used in obtaining the averages. They do not become negative (switch to temporary business cycle hedges) at any point during the study period. Note that all of the stocks' alphas in all of the industries are quite similar in pattern and stability. All of them drop as the US business cycle enters

Table 2b
Electric and gas utility stocks GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
Electric and gas utility stock symbols					
AEE	1.507**	0.000**	0.823***	0.106***	1.81**
AVA	0.980*	0.000***	0.863***	0.150***	0.10
BKL	1.289*	0.000**	0.838***	0.097***	0.71
CHG	2.154***	0.000***	0.823***	0.117***	0.66
CMS	1.469***	0.000***	0.817***	0.180***	1.07
CNP	1.976***	0.000***	0.732***	0.172***	1.99**
CPK	1.896**	0.000	0.961***	0.025**	0.52
D	2.406**	0.000*	0.806***	0.121***	1.08
DTE	2.201***	0.000***	0.852***	0.128***	1.75**
DUK	1.901***	0.000**	0.809***	0.137***	0.31
ED	1.151***	0.000***	0.854***	0.138***	0.49
EDE	2.248***	0.000**	0.806***	0.068***	0.98
ETR	2.273***	0.000***	0.838***	0.124***	0.99
EXC	1.975***	0.000***	0.874***	0.090***	1.05
LNT	2.302**	0.000**	0.775***	0.135***	0.38
MDU	1.642***	0.000***	0.811***	0.115***	1.12
MGEE	2.281**	0.000**	0.765***	0.057**	0.74
NI	1.604**	0.000**	0.818***	0.132***	0.99
NU	1.283*	0.000***	0.838***	0.123***	2.10**
NVE	1.228**	0.000***	0.903***	0.079***	0.35
OGE	2.266***	0.000***	0.777***	0.128***	0.67
PCG	1.836***	0.000***	0.860***	0.118***	0.84
PEG	2.304***	0.000**	0.888***	0.095***	0.72
POM	2.221***	0.000***	0.863***	0.079***	0.40
PPL	1.809***	0.000***	0.829***	0.113***	1.19
SCG	2.401***	0.000***	0.761***	0.150***	0.53
SRE	1.906	0.000	0.806***	0.132*	0.41
TE	1.418**	0.000***	0.823***	0.136***	0.47
TEG	2.856***	0.000*	0.832***	0.086***	0.21
UGI	1.400***	0.000***	0.923***	0.058***	0.37
UIL	1.665**	0.000***	0.764***	0.182***	0.94
UNS	0.764	0.000***	0.864***	0.100***	0.72
UTL	0.822	0.000**	0.715***	0.128**	0.56
VVC	1.896**	0.000***	0.869***	0.081***	0.62
WEC	2.758***	0.000*	0.844***	0.056**	1.15
WR	2.236***	0.000***	0.886***	0.072***	2.04**
XEL	2.633***	0.000***	0.756***	0.167***	0.76

See Table 2a notes.

the great recession from the December 2007 peak to the June 2009 trough and the only recession during the study period (National Bureau of Economic Research, 2015). An increasing (decreasing) alpha indicates that the price of risk has increased (decreased). These alphas are Sharpe ratios (Sharpe, 1994), the ratio of the expected risk premium to conditional volatility. Higher alphas should not be interpreted as higher risk and therefore higher expected rates of return on common equity. A higher price of risk can be associated with lower volatility and lower rather than higher costs of common equity. Alpha is inversely related to the volatility in return in the theoretical development of the model. Therefore a higher volatility is combined with a lower alpha so the overall impact of a higher alpha on the expected rate of return is not clear. It is possible that the drop in alphas approaching and during the recession may be due to investors' flight to quality to assets with lower risk and lower but acceptable return.

Fig. 3 shows the GCAPM cost of common equity results and their trends for each of the public utility industries. The alpha coefficients and predicted monthly volatilities used to estimate the cost of common equity for each public utility stock are estimated using a series of estimated GARCH models for each utility as discussed above. Consistent with Ahern et al. (2011), the *ex ante* common equity risk

Table 2c
Gas (local distribution companies or LDC) utility stocks GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
Gas utility stock symbols					
AGL	2.787***	0.000**	0.803***	0.096***	0.57
ATO	2.143***	0.003***	−0.081	0.261***	0.58
DGAS	2.195*	0.003*	−0.360	0.051	0.23
EGN	2.215***	0.000***	0.766***	0.171***	0.76
EQT	1.814***	0.000***	0.834***	0.131***	0.46
EGAS	1.150	0.000***	0.732***	0.197***	0.36
LG	0.855**	0.000***	0.896***	0.097***	0.66
NFG	1.596***	0.000***	0.901***	0.079***	0.86
NJR	1.944**	0.002***	0.351**	0.276***	0.11
NWN	1.604**	0.000**	0.796***	0.117***	0.92
OKE	1.569***	0.000***	0.810***	0.139***	0.80
PNY	2.287***	0.000***	0.837***	0.106***	0.98
RGCO	2.153***	0.000**	0.962***	-0.059***	0.94
SJI	1.989***	0.000***	0.755***	0.138***	0.94
STR	1.381**	0.001**	0.866***	0.036***	0.11
SWX	1.177*	0.000***	0.823***	0.087***	0.34
WGL	1.092**	0.000***	0.831***	0.170***	0.25
WMB	0.824**	0.000***	0.813***	0.131***	2.68***

See Table 2a notes.

Table 2d
Water utility stocks GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
Water utility stock symbols					
ARTNA	1.879	0.000**	0.838***	0.094**	0.93
AWR	1.389*	0.000*	0.873***	0.047	0.74
CTWS	1.636*	0.001**	0.529***	0.157***	0.44
CWT	1.706**	0.000**	0.793***	0.111***	0.86
MSEX	1.880**	0.000**	0.805***	0.087**	0.94
SJW	1.273*	0.000**	0.911***	0.043***	0.68
WTR	2.110***	0.000***	0.857***	0.079***	1.15
YORW	1.819	0.000	0.852***	0.029	0.63

See Table 2a notes.

premiums were calculated using the average of predicted volatilities (variances) over the entire time period for which CRSP data were available for each utility and then multiplied by α_i's. The GCAPM cost of common equity for each utility was estimated by adding the average predicted utility's common equity risk premium for each month starting in January 2006 through December 2011 to the predicted risk free rate, which is the consensus forecast of the 30 year US Treasury Bonds yield for the next 6 quarters from Blue Chip Financial Forecasts. Fig. 3 shows that the predicted cost of common equity capital results generated by the GCAPM was stable for all utility industries except for the recession and associated global financial market crisis of 2008 and 2009. During that period, predicted GCAPM costs of capital declined. This may have been due to investors' flight to quality to less risk and an acceptable lower return. The GCAPM predicted costs of capital for all of the utility industry groups follow a similar trend except for the water utilities, which had a similar path but much more volatility. Contrasting with the CAPM that uses only one estimated parameter, beta, to establish the uniqueness among each stock, the GCAPM uses two estimated parameters to predict the expected returns, the alpha and the specific stock predicted conditional volatility and three more parameters in the variance prediction model for predicting volatility. Since it is investors' behaviors that cause the level of volatility and due to the fact that the GCAPM uses predicted volatilities to predict the cost of capital, the GCAPM is more

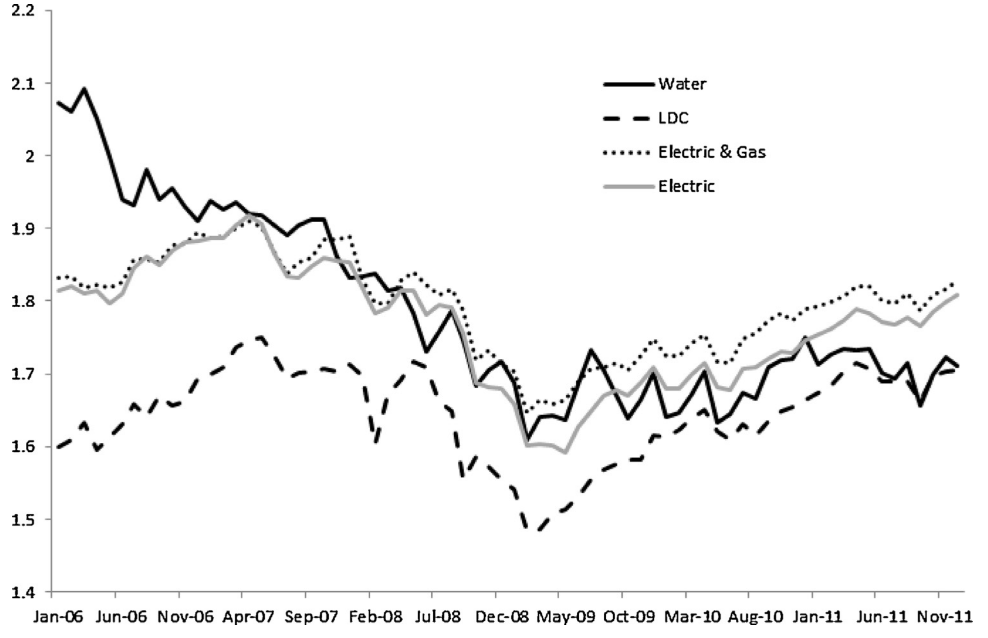

Fig. 2. Alphas (slope on $\sigma^2_{i,t+1}$) from 1/2006 to 12/2011 for electric, electric and gas, gas (local distribution companies or LDC) and water utility stocks. The stocks in each industry are those as defined by AUS Utility Reports® (AUS, 2012). See Table 1 for individual stocks.

intuitive appealing than the CAPM. The CAPM is not a forward-looking model and beta is not a pure measure of risk. It is a mixture of correlation and risk.[4]

Fig. 4 shows the plots the averages of the costs of common equity for each stock estimated with the GCAPM and the CAPM for each of the utility industries. The plots consistently show that the GCAPM generates a substantially higher cost of capital than the CAPM. This may be due to the fact that the GCAPM prices the risk which investors actually face whereas the CAPM prices systematic risk, the only risk that the investor would be exposed if they had a perfectly diversified portfolio, which does not exist in practice. Based on the well-established observation of low R^2's of CAPM regressions, a substantial majority of a stock return's volatility is not explained by the CAPM (Fama & French, 2004) and therefore not priced by the CAPM.

The only recession that occurred during the period shown on the graphs is the great recession that started with the peak at December 2007 and the trough at June 2009 (National Bureau of Economic Research, 2015) as mentioned above. As investors anticipated the future of the business cycle, both the alphas and the costs of common equity peaked as shown in Figs. 2–4 then declined and reached the trough a few months before the business cycle. Note (Fig. 4) that the GCAPM costs of capital peaks and troughs precede those of the CAPM by somewhat less than a year. This suggests that the GCAPM is a forward looking model more than the CAPM as it leads CAPM peaks and troughs in the cost of capital and is able to anticipate CAPM generated trends in the cost of capital. This evidence is not meant to conclude that the CAPM should be replaced by the GCAPM. Until one model un-equivocally produces results deemed to be closer to the true cost of common equity, no information should be ignored for consideration in estimating the cost of common equity. This investigation suggests that the GCAPM

[4] The CAPM beta is defined as $\beta_i = \rho_{i,m}\, \sigma_i\, \sigma_m / \sigma_m{}^2$ where $\rho_{i,m}$ is the correlation between the returns on stock i and the market, and the σ's are the standard deviations on stock i and market returns (m). Since the expression can be simplified to $\beta_i = \rho_{i,m}$ (σ_i/σ_m), only the ratio of standard deviation of the stock to the market return represents volatility and therefore risk. So the CAPM beta is a mixture of correlation and risk. A high ratio of volatility of a stock's return relative to the market combined with a low correlation can result in a low beta, reflecting low risk.

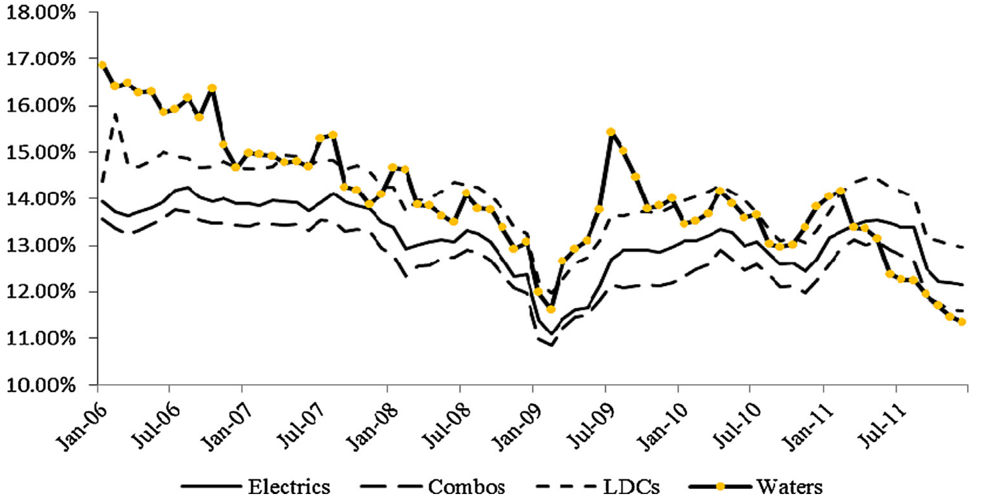

Fig. 3. GCAPM cost of common equity estimates for US publicly traded public utilities.

model contributes additional information that should be considered in the process for estimating the costs of common equity. Hopefully, additional information and technologies will diffuse into the process rather than almost sole reliance on the CAPM.

Michelfelder, Ahern, D'Ascendis, and Hanley (2013) show the trends in the cost of common equity estimates by each asset model for each industry. They perform a comparison of the results of the two typical used asset pricing models, the DCF and CAPM with the GCAPM. The GCAPM generally produces higher predicted ROE's than either the DCF or CAPM. Since the GCAPM prices the actual risk faced by the investor rather than the lower, unrealistic ideal (perfectly diversified portfolio) level assumed by the CAPM, this result is not surprising. Public utilities are not investing the level of capital investment necessary to maintain the current level of service, much lesser than the capital needed for growth in their service areas. Regulated allowed rates of return on common equity lower than the costs of common equity may be the cause of public utilities lack of investment that is expected to generate deterioration of service and inhibit economic growth if it does not change soon. For example, the Brattle Group, Fox-Penner, Chupka, and Earle (2008) estimates that the US electric power industry will have to invest \$1.5 trillion to \$2.0 trillion by 2030 to maintain the current level of reliability. Brennan (2008) shows that electricity transmission capacity peaked in 1982 and that both capacity and investment has been on a long-term declining trend. According to the US EPA's 2011 Drinking Water Infrastructure Needs Survey and Assessment (EPA, 2011), by 2030 the industry will require \$384.2 billion in 2011 dollars in system upgrades to maintain safe drinking water service. Such a huge level of investment will cause water rates and bills to rise to levels similar to electricity bills.

5. Robustness tests

Robustness tests are performed with the inclusion of an intercept, differing specifications of conditional volatility, and the use of the Fama–French risk-free rate for generating risk premia. The estimation results are poor with the inclusion of an intercept therefore the model is well specified. All of the model estimations are robust to changes in specifications of the conditional volatility using standard deviation and the natural log of variance as other measures. Similarly, the estimations are robust to choice of risk-free rate.

One concern is the intertemporal stability of the alphas. The alpha in the model is a function of conditional variance and is time varying as the conditional standard deviation of the return is included in the conditional correlation of the stochastic discount factor and the return. The averages of the alpha estimates are plotted over time for each utility to review stability of the hedging property of the assets

Fig. 4. Plots of GCAPM and CAPM costs of common equity estimates for electric, electric and gas, gas, and water utility stocks.

over time. Fig. 2, as already discussed, plots the updated monthly alphas over 72 months (January 2006 to December 2011). The alpha values are highly stable and never get close to zero and, generally, there are no discontinuous spikes in alpha in either direction for each utility stock.

6. Conclusion

Based on the results of this empirical study, Ahern et al. (2011), Michelfelder et al. (2013), and Michelfelder and Pilotte (2011), a literature is beginning to emerge that supports the GCAPM as additional evidence for estimating the cost of common equity capital. This study found that the model fits the data well across all US publicly traded utility stocks and the US stock market as a single portfolio. The estimates are consistent, stable, and show that utility stocks are not a business cycle hedge. There would be a stability concern if some utility stocks were hedges and others were not or if stocks temporarily switched to hedging assets.

The GCAPM has been successfully empirically tested for public utilities and the US stock market in this study and preliminarily in Ahern et al. (2011), and for US Treasury Bills and Bonds in Michelfelder and Pilotte (2011). However, a comprehensive study across a spectrum of common equity assets, at least for non-public-utility individual stocks, is needed as an important next step to consider the widespread adoption of the GCAPM as a method to estimate the cost of common equity capital for stocks in general. This paper is a component of a research program toward that goal. The motivation was to empirically test and discuss the results in sufficient technical detail to assess the relevance of the model for public utility cost of common equity capital estimation and the cost of capital for any firm. Secondly, the motivation was to build a platform for further research of the GCAPM for estimating the rate of return for any stock, as stated above. Finally, the GCAPM was tested as a potential cost of capital model to help update and improve on the cost of capital technology by providing additional information. This paper does not suggest that the GCAPM supplant any other cost of capital pricing model. It does recommend that it be considered as an additional model for developing the cost of capital estimates.

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ORIGINAL ARTICLE

New approach to estimating the cost of common equity capital for public utilities

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Abstract The regulatory process for setting public utilities' allowed rate of return on common equity has generally used the Gordon DCF, CAPM and Risk Premium specifications to estimate the cost of common equity. Despite the widely known problems with these models, there has been little movement to adopt more recently developed asset pricing models to provide additional evidence for estimating the cost of capital. This paper presents, validates empirically and applies a general yet simple consumption-based asset pricing specification to model the risk-return relationship for stocks and estimate the cost of common equity for public utilities. The model is not necessarily superior to other models in its practical results, yet these results do indicate that it should be used to provide additional estimates of the cost of common equity. Additionally, the model raises doubts as to whether assets such as utility stocks are a consumption (business cycle) hedge.

Keywords Public utilities · Cost of capital · GARCH · Consumption asset pricing model

JEL Classification G12 · L94 · L95

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1 Introduction

Following electricity deregulation with the National Energy Policy Act of 1992, the estimation of the cost of common equity capital remains a critical component of the utility rate-of-return regulatory process. Since the cost of common equity is not observable in capital markets, it must be inferred from asset pricing models. The models that are commonly applied in regulatory proceedings are the Gordon (1974) Discounted Cash Flow (DCF), the Capital Asset Pricing (CAPM) and Risk Premium Models. There are other tools used to estimate the cost of common equity such as comparable earnings or earnings-to-price ratios, but they are not asset pricing models. The empirical literature on the CAPM is vast {Fama and French (2004)} and the CAPM is used by a number of US regulatory jurisdictions. The DCF model has not been empirically tested to the same extent as the CAPM, yet it is considered by many US regulatory jurisdictions.

The purpose of this paper is to present, test empirically and apply a recently developed general consumption-based asset pricing model that estimates the risk-return relationship directly from asset pricing data and, when estimated with recently developed time series methods, produces a prediction of the equity risk premium that is driven by its predicted volatility. The predicted risk premium is then added to a risk-free rate of return to provide an estimate of the cost of common equity. We predict two forms of the equity risk premium with the model, the risk premium net of the risk-free rate and the equity-to-debt risk premium (equity risk premium net of the relevant bond yield for the company's stock). Either can be applied to predict the common equity cost of capital for a public utility. Although the model is tested and applied to public utilities for rate of return regulation, it can be used to estimate the cost of capital for any stock. Section 2 reviews the asset pricing models typically used in public utility rate cases and the generalized consumption asset pricing model we propose to estimate the cost of common equity. Section 3 discusses the data and the empirical testing of the consumption asset pricing model. Section 4 reviews the application of the model and compares it with the DCF and CAPM results. Section 5 is the conclusion.

2 DCF, CAPM and consumption asset pricing model

2.1 DCF and CAPM approaches

The standard DCF model frequently used in estimative the cost rate of common equity in regulatory proceedings is defined by the following equation:

$$k = D_0\,(1+g)\,/P_0 + g,$$

where k is the expected return on common equity; D_0 is the current dividend per share; g is the expected dividend per share growth rate; and P_0 is the current market price.

The DCF was developed by Gordon (1974) specifically for regulatory purposes. Underlying the DCF model is the theory that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate which is derived from cash flows received in the form of dividends plus appreciation in market price (the expected growth rate) over the investment holding period. Mathematically, the expected dividend yield $(D_0(1+g)/P_0)$ on market price plus an expected growth rate equals the capitalization rate, i.e., the expected return on common equity.

The standard DCF contains several restrictive assumptions, the most contentious of which during utility cost of capital proceedings is typically that dividends per share (DPS), book value per share (BVPS), earnings per share (EPS) as well as market price grow at the same rate in perpetuity. There is also considerable contention over the proper proxy for g, prospective or historical growth in DPS, BVPS, EPS and market price and over what time period. In addition, although the standard DCF described above is a single stage annual growth model, there is considerable discussion over the use of multiple stage growth models during regulatory proceedings. Some analysts use the discrete version and others use the continuous version of the DCF model. Solving these models for k, the cost of common equity, results in differing equations to solve for k. The equation above is from the discrete version. The continuous version uses the current dividend yield and is not adjusted by g, which results in a lower estimate for k. Because of these and other restrictive assumptions that require numerous subjective judgments in application, it is often difficult for regulatory commissions to reconcile the frequently large disparities in rates of return on common equity recommended by various parties in a public utility rate case.

The CAPM model is defined by the following equation:

$$k = R_f + \beta \left(R_m - R_f \right),$$

where k is the expected return on common equity; R_f is the expected risk-free rate of return; β is the expected beta; and R_m is the expected market return.

CAPM theory defines risk as the co-variability of a security's returns with the market's returns or β, also known as systematic or market risk, with the market beta being defined as 1.0. Because CAPM theory assumes that all investors hold perfectly diversified portfolios, they are presumed to be exposed only to systematic risk and the market (according to the model) will not reward them a risk premium for unsystematic or non-market risk. In other words, the CAPM presumes that investors require compensation only for systematic or market risks which are due to macroeconomic and other events that affect the returns on all assets. Mathematically, the CAPM is applied by adding a forward-looking risk-free rate of return to an expected market equity risk premium adjusted proportionately by the expected beta to reflect the systematic risk.

As with the DCF, there is considerable contention during regulatory cost of capital proceedings as to the proper proxies for all components of the CAPM: the R_f, the R_m, as well as β. In addition, the CAPM assumption that the market will only reward investors for systematic or market risk is extremely restrictive when estimating the expected return on common equity for a single asset such as a single jurisdictional regulated operating utility. Additionally, this assumption requires that the investor have a perfectly diversified portfolio, that is, one with no unsystematic risk. Since this assumption is not applicable, estimating the cost of common equity capital for a single utility's common equity undoubtedly will not reflect the risk actually faced by the imperfectly diversified investor.

As will be discussed in the next section, our application of the risk premium approach, the consumption asset pricing model and GARCH[1] rest on minimal assumptions and restrictions and therefore requires considerably less judgment in its application.

2.2 Risk premium approach, consumption asset pricing models, and GARCH

A widely used model to estimate the cost of common equity capital for public utilities is the risk premium approach. This approach often estimates the expected rate of return as the long-term historic mean of the realized risk premium above an historic yield plus the current yield of the relevant bond applicable to a specific utility or peer group of utilities. Litigants in public utility rate proceedings debate the choice of inputs to estimate the risk premium as well as how far back to reach into history to collect data for calculating an average that is representative of a forward-looking premium.

It is surprising that, as popular as the risk premium method is in public utility rate cases, the intuitively appealing general consumption-based asset pricing model, with its minimal assumptions and strong theoretical foundation, has not been applied to estimate the cost of common equity capital for public utilities. The model provides projections of the conditional expected risk premium on an asset based on its relation to its predicted conditional volatility. This model generalizes the well known special case asset pricing models such as the Merton (1973) intertemporal capital asset pricing model, Campbell (1993) intertemporal asset pricing model, and the habit-persistence model of Campbell and Cochrane (1999), which are special cases of the general model. The relation of the model to their specialized cases can be found in Cochrane (2006) and Cochrane (2007). The approach of consumption asset pricing models is to make investment decisions that maximize investors' utility from the consumption that they ultimately desire, not returns.

Even if the model is not used to project directly the expected risk premium, it can, at a minimum, be used to verify that the risk premia data chosen for estimating the cost of capital is empirically validated by fitting the model well. The model can be used to predict the equity risk premia net of the risk-free rate (equity risk premium) or to predict the equity-to-debt risk premium for a firm. We perform both of these empirical tests in this paper. The general consumption-based asset pricing model developed in Michelfelder and Pilotte (2011) and based on Cochrane (2004) provides the relationship of the ex ante risk premium to an asset's own volatility in return:

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{vol_t[M_{t+1}]}{E_t\left[M_{t+1}\right]} vol_t[R_{i,t+1}] corr_t[M_{t+1}, R_{i,t+1}]. \tag{1}$$

[1] GARCH refers to the generalized autoregressive conditional heteroskedasticity regression model which is discussed below.

where vol_t is the conditional volatility, $corr_t$ is the conditional correlation, and M_{t+1} is the stochastic discount factor (SDF).

The SDF is the intertemporal marginal rate of substitution in consumption, or, $M_{t+1} = \beta \frac{U_{c,t+1}}{U_{c,t}}$, where the U_c's are the marginal utilities of consumption in the next period, $t+1$, and the current period, t, and β is the discount factor for period t to $t+1$. Equation 1 shows that the algebraic sign of the relation between the expected risk premium and the conditional volatility of an asset's risk premium is determined by the correlation between the asset's return and the SDF. That is, the direction of the relation between the asset return and the ratio of intertemporal marginal utilities in consumption inversely determines the relation between the expected risk premium and conditional volatility. When the correlation is equal to negative one, the asset's conditional expected risk premium is perfectly positively correlated with its conditional volatility. A positive relation between the conditionally expected risk premium and volatility obtains when $-1 < corr_t < 0$. A negative relation obtains when $0 < corr_t < 1$. For an asset that represents a perfect hedge against shocks to the marginal utility of consumption, with $corr_t = 1$, there will be a perfect negative correlation between the conditionally expected risk premium and its volatility.[2] Therefore, estimates of the relation between the first two conditional moments of a public utility stock's returns provide a direct test of the effectiveness of a public utility stock, or any asset, as a consumption hedging asset. In Eq. 1, $vol_t[M_{t+1}]/E_t[M_{t+1}]$ is the slope of the mean-variance frontier. If this slope changes over time, the estimated relation between the stock's risk and return will vary over time. This model can also be viewed simplistically as the projected expected risk premium as a function of its own projected risk, given information available at time t.

Note that the model allows for the expected risk premium to be negative if the asset hedges shocks to the marginal utility of consumption. Investors are willing to accept an expected rate of return lower than the risk-free rate of return if the pattern of volatility is such that returns are expected to rise with expected reductions in consumption. Simply, investors are willing to *pay* a premium for a higher level of returns volatility that has the desired pattern of returns. These desired returns patterns have a tendency to offset drops in consumption. Therefore, this model shows that investors may not be averse to volatility, but rather to the timing of expected changes in returns.

Summarizing, several conclusions can be drawn from the general model of asset pricing. First, the sign of the relation between a stock's risk premium and conditional volatility depends on the extent to which the stock serves as an intertemporal hedge against shocks to the marginal utility of consumption. Second, the relation between stock risk and return may be time-varying depending on changes in the slope of the mean-variance frontier. Third, hedging assets have desired patterns of volatility that result in expected rates of return that are less than the risk-free rate. We do not expect

[2] A hedging asset is one that has a positive increase in returns that is coincident with a positive shock in the ratio of intertemporal marginal utilities of consumption. Note that if we assume a concave utility function in consumption, as consumption declines, the marginal utility of consumption rises relative to last period marginal utility. If we think of a decline in consumption as a contraction in the business cycle, the hedging asset delivers positive changes in returns when the business cycle is moving into a contraction, and therefore the asset is a business cycle hedge.

that public utility stocks serve as a hedging asset as they are not viewed as defensive stocks (they do not rise in value during downturns in the stock market) due to asymmetric regulation and returns as discussed in detail in Kolbe and Tye (1990). Under asymmetric regulation, utility regulators have a tendency to allow the return on equity to fall below the allowed return during downturns in the business cycle and to reduce the return should it rise above the allowed return during expansions. Therefore we expect that the parameter estimates of the return-risk relationship to be positive as utility stocks are hypothesized to not be hedges.

We use the GARCH model to estimate the general asset pricing model since the GARCH model accommodates ARCH effects that improve the efficiency of the parameter estimates. It also provides a volatility forecasting model for the conditional volatility of the asset's risk premium. The conditional volatility projection is used, in turn to predict the expected risk premium. We also use the GARCH-in-Mean model (GARCH-M) since it specifies that the conditional expected risk premium is a linear function of its conditional volatility. There is a vast body of literature that estimates asset pricing models with the GARCH and GARCH-M methods and therefore we will not attempt to summarize them here.

The GARCH-M model was initially developed and tested by Engle et al. (1987) to estimate the relationship between US Treasury and corporate bond risk premia and their expected volatilities. The GARCH-M model is specified as:

$$R_{t+1} - R_{f,t+1} = \alpha\sigma_{t+1}^2 + \varepsilon_{t+1} \tag{2}$$

$$\sigma_{t+1}^2 = \beta_0 + \beta_1\sigma_t^2 + \beta_2\varepsilon_t^2 + \eta_{t+1} \tag{3}$$

$$\varepsilon_t \,|\psi_{t-1} \sim T(0, \sigma_t^2) \tag{4}$$

where R_{t+1} is the expected total return on the public utility stock index or individual utility stock; $R_{f,t+1}$ is the risk-free rate of return or the yield on an index of public utility bonds of a specified bond rating for the equity-to-debt premium; σ_{t+1}^2 is the conditional or predicted variance of the risk premium that is conditioned on past information (ψ_{t-1}); and ε_t is the error term that is conditional on ψ_{t-1}.

The conditional distribution of the error term is specified as the non-unitary variance T-distribution due to the thick-tailed distribution of the risk premia data. If the error distribution is thick-tailed, using an approximating distribution that accommodates thick tails improves the efficiency of the estimates. The parameter, α, is the return-to-risk coefficient as specified in Eq. 1 as:

$$\alpha = -\frac{vol_t[M_{t+1}]}{E_t\left[M_{t+1}\right]} corr_t[M_{t+1}, R_{i,t+1}] \tag{5}$$

Note that the coefficient will be positive if the conditional correlation between the SDF and the asset return is negative, indicating that the stock is not a hedging asset. Recall that the SDF is the ratio of intertemporal marginal utilities. Assuming a concave utility function, an upward shock in the ratio implies falling consumption, therefore an associated rise (positive correlation) in the return (R_i) would offset the reduction in consumption, thereby causing the sign of α to be negative. The parameter, α, is also the ratio of risk premium to variance, or, the Sharpe ratio.

The intercept in Eq. 2 is restricted to zero as specified by the general asset pricing model specification. The restriction on the intercept equal to zero has been found to be robust in producing consistently positive and significant relationships between equity risk premia and risk in GARCH-M models. This is discussed in Lanne and Saikkonen (2006) and Lanne and Luoto (2007). We have found the same results in our modeling in this paper, although we have excluded these results for brevity (available upon request). Therefore we specify the prior assumption that the intercept or the "excess" return, i.e., the return not associated with risk to be equal to zero and drop the intercept from the model.

The consumption asset pricing model is estimated in the empirical section of the paper and applied in the applications section of the paper. The model is tested to (1) determine if equity-to-debt risk premium indices for utilities of differing risk specified by differing bond ratings are validated by the asset pricing model and therefore have some empirical support for risk premium prediction and application to utility cost of capital estimation, (2) determine whether equity risk premia can be predicted and fit the model and therefore be used to estimate the cost of common equity, (3) empirically test the consumption asset pricing model, and (4) ascertain whether utility stocks are assets that hedge shocks to the marginal utility of consumption.

If utility stocks are hedging assets then the cost of common equity should reflect a downward adjustment to a specified risk-free rate to reflect investors' preferences for a hedge and the compensation that they are willing to pay for it.

3 Data and empirical results

We use portfolios as represented by public utility stock and bond indices to estimate the conditional return-risk relationship for the equity-to-debt premium. The equity-to-debt risk premium data employed for estimating Eq. 1 with the GARCH-M conditional return-risk regressions are monthly total returns on the Standard and Poor's Public Utilities Stock Index (utility portfolio), and the monthly Moody's Public Utility Aa, A, and Baa yields for the debt cost. We also obtained equity risk premia for the utility portfolio using the Fama-French specified risk-free rate of return, which is the holding period return on a 1-month US Treasury Bill. The data range from January 1928 to December 2007 with 960 observations. The return-risk relationships for the equity-to-debt premia are risk-differentiated by their own bond rating.

As a check, we also estimate Eq. 1 with the GARCH-M for large common stock returns using the monthly Ibbotson Large Company Common Stocks Portfolio total returns and the Ibbotson US Long-Term Government income returns as the risk-free rate. Additionally, as another check, we do the same for the University of Chicago's Center for Research in Security Prices value-weighted stock index (CRSP) using the Fama-French risk-free rate. This is the Fama-French specification of the market equity risk premium. The data range from January 1926 to December 2007 with 984 observations for the Large Company Common Stock estimation and the data ranges

Table 1 Descriptive statistics: public utility and large company common stocks equity-to-debt and equity risk premia

Utility bond rating	Mean	Std. Dev.	Skewness	Kurtosis	JB
Aa	0.0037	0.0568	0.0744	10.07	2,001.2***
A	0.0035	0.0568	0.0632	10.06	1,991.8***
Baa	0.0031	0.0568	0.0375	10.02	1,973.6***
Ibbotson					
Large common stocks	0.0054	0.0554	0.4300	12.84	3,954.7***
CRSP value-weighted stock index	0.0062	0.0544	0.2309	10.92	2,519.1***

The public utility equity-to-debt risk premia monthly time series is from January 1928 to December 2007 with 960 observations. The equity risk premium monthly time series for the Large Common Stocks and the CRSP index are January 1926 to December 2007 with 984 observations, and January 1926 to December 2007 with 984 observations, respectively. The public utility stocks equity-to-debt risk premia are calculated as the total return on the S&P Public Utilities Index of stocks minus the Moody's Public Utility Aa, A, and Baa Indices yields to maturity. The Large Company Common Stock equity risk premia are the monthly total returns on the Ibbotson Large Company Common Stocks Portfolio minus the Ibbotson Long-Term US Government Bonds Portfolio income yield. The CRSP equity risk premia, or the Fama-French market risk premia are the CRSP total returns on the value-weighted equity index minus the 1-month holding period return on a 1 month Treasury Bill. The Jarque-Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of a data series from normality, based on the levels of skewness and excess kurtosis. The JB statistic is χ^2 distributed with 2° of freedom. *** Significant at 0.01 level, one-tailed test

from January 1928 to January 2007 with 960 observations (same as the utilities) for the CRSP estimation.

Table 1 displays the descriptive statistics for these data. We have estimated the mean, standard deviation, skewness and kurtosis parameters, as well as the Jarque-Bera (JB) statistic to test the distribution of the data. The means of the utility equity-to-debt risk premia fall as the risk (bond rating) declines. This is consistent with the notion that larger yields are subtracted from stock returns the lower the bond rating. Intertemporally, there is an inverse relationship between risk premia and interest rates (See Brigham et al. (1985) and Harris et al. (2003)). The mean for risk premia will have a tendency to be larger during low interest rate periods.

Not surprisingly, large company common stocks have the highest mean risk premia as the majority of these firms are not rate-of-return regulated firms with a ceiling on their ROE's close to their cost of capital. Interestingly, the standard deviations of the utility stock returns are similar and slightly higher than large company common stocks. Skewness coefficients are small and positive except for Ibbotson large company common stock returns and CRSP returns that have large positive skewness. This suggests that large unregulated stocks have a tendency to have more and larger positive shocks in returns than do utilities that are rate of return regulated. The kurtosis values show that all of the risk premia are thick-tail distributed. This is also found in the significant JB statistics that test the null hypothesis that the data are normally distributed. The null hypothesis is rejected for all assets. The high kurtosis, low skewness, and significant JB statistics show that the risk premia data are substantially thick-tailed, except for non-utility stocks that are both skewed and thick-tailed. Therefore, robust estimation methods are required to produce efficient regression estimates with non-normal data. Additionally, although not shown but available upon request, the serial correlation and

ARCH Lagrange Multiplier tests show that residuals from OLS regressions of risk premia on volatilities follow an ARCH process. Therefore, the GARCH-M method will improve the efficiency of the estimates. We specify the regression error distribution as a non-unitary variance T-distribution so that thick-tails could be accommodated in the estimation and therefore produce increasingly efficient parameter estimates.

We used maximum likelihood estimation with the likelihood function specified with the non-unitary-variance T-distribution as the approximating distribution of the residuals to accommodate the thick-tailed nature of the error distribution. The equations are estimated as a system using the Marquardt iterative optimization algorithm. The chosen software for estimating the model was EViews© version 6.0 (2007).

Table 2 shows the GARCH-M estimations for the consumption asset pricing Eq. 1. We have estimated Eq. 1 for the utility equity risk premia using the Fama-French risk-free rate in addition to the equity-to-debt risk premia risk-differentiated by bond ratings and the two measures of the market equity risk premium. The chosen measure of volatility is the variance of risk premium (in contrast to other such measures such as the standard deviation or the log of variance. Although these results are not shown for brevity, they are robust to these other measures of volatility). The slope, which is the predicted return-to-predicted risk coefficient and Sharpe ratio, is positive and significant at the 99% level for all assets except the utility stock returns with Baa bonds, which is significant at the 95% level. Given that all slopes are positive, public utility stocks are not found to hedge shocks to the marginal utility of consumption. Note that the reward-to-risk slope rises as bond rating rises. This suggests that lower risk utility stocks provide a higher incremental risk-premium for an increase in conditional volatility. This is consistent with other studies that find that lower risk assets, such as shorter maturity bonds, have higher Sharpe Ratios than long-term bonds and stocks. See Pilotte and Sterbenz (2006) and Michelfelder and Pilotte (2011).

The variance equation shows that all GARCH coefficients (β's) are significant at the 1% level and the sums of β_1 and β_2 are close to, but less than 1.0, indicating that the residuals of the risk premium equation follow a GARCH process and that the persistence of a volatility shock on returns and stock prices for utility stocks is temporary. The estimates of the non-unitary variance T-distribution degrees of freedom parameter are low and statistically significant, indicating that the residuals are well approximated by the T. Similar values for the log-likelihood functions (Log-L) show that each of the regressions has a similar goodness-of-fit. Chi-squared distributed likelihood ratio tests (not shown but available upon request) that compare the goodness of fit among the T and normal specifications of the likelihood function of the GARCH-M regressions show that the T has a significantly better fit than the normal distribution.

The GARCH-M results for the large company common stocks portfolio are similar to those of the utility stocks. Not surprisingly, large company common stocks do not hedge shocks to the marginal utility of consumption and volatility shocks temporarily affect their valuations. The exception is that the return-risk slope is substantially higher than utility stock slopes. This is partially due to the risk-free nature of the risk-free rates used with the non-utility equity risk premia compared to the

Table 2 Estimation of return-risk relation: public utility and large company common stocks

Utility bond rating	α	β_0	β_1	β_2	Log-L	T dist. D.F.
Aa	1.5183*** (0.5308)	0.0000** (0.0000)	0.8791*** (0.0230)	0.1031*** (0.0219)	1,604.4	9.9254*** (3.0272)
A	1.4536*** (0.5308)	0.0000** (0.0000)	0.8790*** (0.0230)	0.1033*** (0.0220)	1,605.0	9.9381*** (3.0408)
Baa	1.3318** (0.5303)	0.0000** (0.0000)	0.8789*** (0.0229)	0.1040*** (0.0220)	1,605.2	10.0*** (3.0540)
Fama-French R_f	2.1428*** (0.5318)	0.0000** (0.0000)	0.8811*** (0.0232)	0.0979*** (0.0212)	1,601.0	9.8773*** (2.9700)
Ibbotson						
Large company common stocks	2.7753*** (0.5513)	0.0001*** (0.0000)	0.8381*** (0.0269)	0.1186*** (0.0332)	1,620.8	8.8457*** (2.1613)
CRSP value-weighted stock index	3.3873*** (0.5673)	0.0001*** (0.0000)	0.8330*** (0.0270)	0.1149*** (0.0358)	1,598.9	8.8571*** (1.9505)

The results below are the GARCH-in-Mean regressions for the risk premium $(R_{t+1} - R_{f,t+1})$ on the conditional variance of the risk premium (σ^2_{t+1}) in the mean equation. The intercept in the mean equation is restricted to be equal to zero. The public utility equity-to-debt risk premia monthly time series is from January 1928 to December 2007 with 960 observations. The equity risk premium monthly time series for the Large Company Common Stocks and the CRSP index are January 1926 to December 2007 with 984 observations, and January 1926 to December 2007 with 984 observations, respectively. The public utility stocks equity-to-debt risk premia are calculated as the total return on the S&P Public Utilities Index of stocks minus the Moody's Public Utility Aa, A, and Baa Indices yields to maturity. The Large Company Common Stock equity risk premia are the monthly total returns on the Ibbotson Large Company Common Stocks Portfolio minus the Ibbotson Long-Term US Government Bonds Portfolio income yield. The CRSP equity risk premia, or the Fama-French market risk premia are the CRSP total returns on the value-weighted equity index minus the 1-month holding period return on a 1 month Treasury Bill. The estimated model is:

$$R_{t+1} - R_{f,t+1} = \alpha\sigma^2_{t+1} + \varepsilon_{t+1} \text{ where } \alpha = -\frac{vol_t[M_{t+1}]}{E_t[M_{t+1}]} corr_t[M_{t+1}, R_{i,t+1}]$$

$$\sigma^2_{t+1} = \beta_0 + \beta_1\sigma^2_t + \beta_2\varepsilon^2_t + \eta_{t+1}$$

The conditional distribution of the error term is the non-unitary variance T-distribution to accommodate the kurtosis of the risk premia and error term. Standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05, and 0.10 levels, respectively for two-tail tests

utility bond yields that reflect risk. The utility stocks slope value of 2.1428 using the Fama-French risk-free rate is closer to the higher CRSP value of 3.3873 that is also based on the Fama-French risk-free rate. This is inconsistent with previous results herein and in other papers that find that Sharpe Ratios are lower for higher risk assets unless this finding can be interpreted as utility stocks having more risk than non-regulated stocks. The standard deviations on Table 1 suggest that utility stock return volatilities are as high as the stock returns of non-regulated firms. However, similar model estimates of portfolios of common stocks yield unstable results, such as negative as well as positive return-risk slopes when the intercept is not restricted to zero. See Campbell (1987), Glosten et al. (1993), Harvey (2001), and Whitelaw (1994).

Stock market results are highly sensitive to empirical model specification. Many studies do not consider the impact of a zero-intercept prior restriction on the stability of their results. This simple innovation has led to more consistent results in modeling stock market risk-return relationships, and therefore we have included it in this paper.

The estimation of the consumption asset pricing model for utility stock equity-debt risk premia shows that the use of bond-rating risk-differentiated risk premia are validated as their risk-return relationships are well-fitted by theoretical and empirical models of risk and return. Therefore, these data impound good representations of the risk and reward relationship.

One concern is the intertemporal stability of the alphas. Figure 1 plots the utility stock portfolio alpha (using the Fama-French R_f to calculate the premium) and its standard error for 240 month rolling regressions of the model estimated with GARCH-M in the same manner as described above to review the intertemporal stability of the alpha. A 20-year period was used for each estimation to trade off timeliness with sufficient observation of up and down stock market regimes and business cycles. This resulted in 720 estimated alphas from 1947 to 2007. The results show that the utility alpha is stable to the extent that the algebraic sign is always positive and generally significant, therefore the nature of utility stocks are assets that are not and have never been hedges during the second half of the twentieth century up to the present. The value of the alpha does change substantially. The mean of the alpha is 4.40 with a range from -0.11 (insignificantly different from 0) to 11.66. As a comparison, the alpha for the CRSP value-weighted stock index was also estimated with rolling regressions in the same manner and for the same time period. Figure 2 is a plot of the CRSP alpha and standard error. Note that the general stock market alpha is similar to that of utility stocks. They are all positive and almost all statistically significant and follow a strikingly similar cycle. Figure 3 plots both the utility and stock market alphas and demonstrates the similarity. The correlation coefficient between the utility and stock market alphas is 0.88. Recalling that the alpha is a Sharpe Ratio, we see that return to risk ratio does change substantially. This is consistent with the results in Pilotte and Sterbenz (2006).

One other interesting observation is that the standard errors of the alphas are highly stable over the study period and are very similar in magnitude regardless of the size of the corresponding alpha. Whereas the alpha follows a cyclical pattern, the volatility in alpha is highly stationary around a constant, long-run mean.

The GARCH-M model estimations of the consumption asset pricing model were specified with variance as the measure of volatility. We also performed the same model estimations with alternative specifications of volatility such as the standard deviation and the log of variance and the results were not sensitive to this specification.

4 Application

We apply the model in this section to compare the cost of common equity capital estimates with the DCF and CAPM models. Using EViews© Version 6.0, we estimated the model coefficients (α, $\beta's$) over rolling 24 month periods ending December 2008.

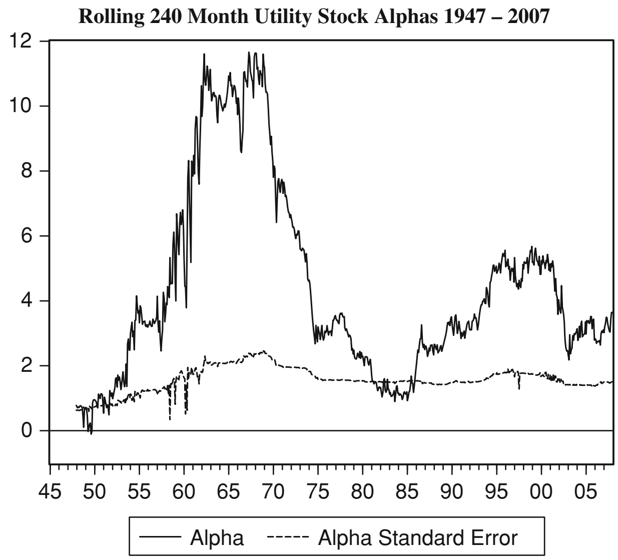


Fig. 1 Rolling 240 month utility stock alphas 1947–2007

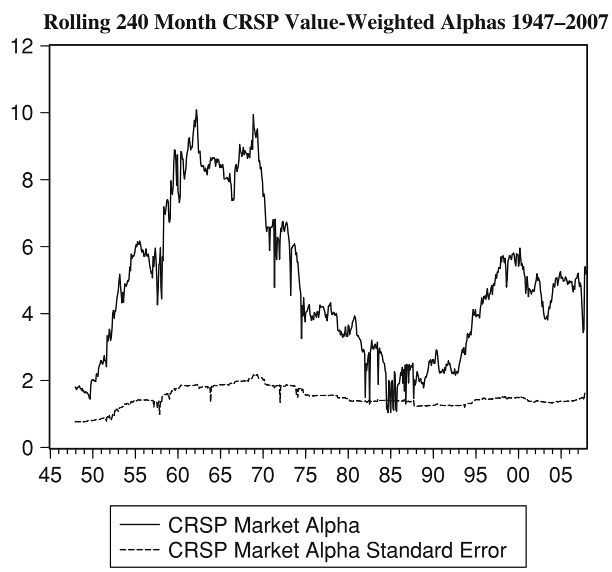


Fig. 2 Rolling 240 month CRSP value-weighted alphas 1947–2007

We repeated the estimation over 5, 10, 15, 20 and 79 year periods.[3] Predicted monthly variances (σ^2_{t+1}) were generated from these estimations to produce predicted risk premiums that were calculated by multiplying the predicted variance by the "α" slope

[3] We did not include the results of the 10 and 15 year estimations to abbreviate the amount of empirical results presented since they added no material insights beyond those already presented.

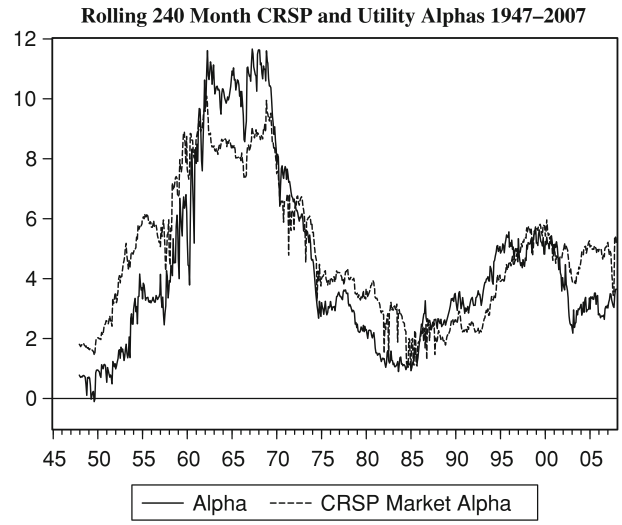


Fig. 3 Rolling 240 month CRSP and utility alphas 1947–2007

Table 3 Estimates of expected risk premia

	Mean (%)		Range (%)		Standard deviation (%)	
	Average	Spot	Average	Spot	Average	Spot
Ibbotson Associates data						
79-years	9.59	5.76	8.74–9.96	2.62–22.60	0.32	5.24
20-years	6.77	6.94	4.99–8.50	2.24–28.95	0.95	6.88
5-years	4.20	10.25	−98.49–11.62	−100.00–39.65	22.00	26.61
S&P Utility Index						
79-years	5.28	2.90	4.30–5.28	1.65–8.15	0.32	1.60
20-years	3.93	3.51	2.78–5.03	2.18–6.88	0.57	1.11
5-years	31.82	326.63	7.77–156.97	6.12–6465.74	31.47	1283.51

coefficient. To test the stability of the predicted risk premia over time, the predicted risk premia were calculated using either the predicted variance over each entire time period or the last monthly (spot) predicted variance. Table 3 presents the mean predicted risk premia, the range of predicted premia and the standard deviations for each time period. It is clear from the results that the risk premia are more stable over the rolling 24 month period when calculated using the average predicted variance compared with using the spot variance. Secondly, the 20 and 79 year means are substantially more stable and reasonable in magnitude than the 5 year means.

Next, given the lessons from the analyses above, we apply the model to mechanically[4] estimate the cost of common equity for 8 utility companies using the model and

[4] The term "mechanically" in this context means that the resulting values have been developed in a consistent manner with the same inputs across all utility stocks but no subjective judgment was used to develop final values for each specific utility stock application.

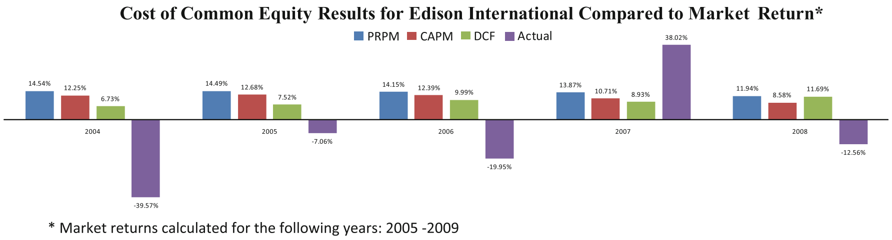
the DCF and CAPM as comparisons. We also calculated the realized market return for comparison. Two publicly-traded electric, electric and gas combination, gas, and water utilities respectively were chosen for the application. The Gordon (1974) DCF and CAPM models are used in many utility regulatory jurisdictions in the US.

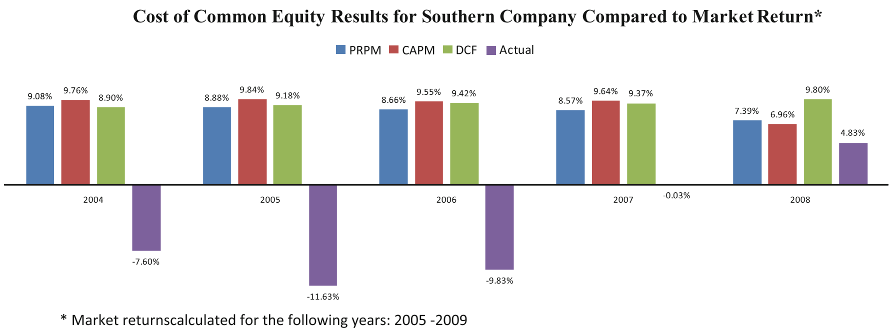
The DCF was applied using a dividend yield, D_0/P_0, derived by dividing the year-end indicated dividend per share (D_0) by the year-end spot market price (P_0). The dividend yield is grown by the year-end I/B/E/S five year projected earnings per share growth rate (g) to derive $D_0(1+g)/P_0$. The one-year predicted dividend yield is then added to the I/B/E/S five-year projected EPS growth rate to obtain the DCF estimate of the cost of common equity capital, k. This study was conducted for the 5 years ending 2008.

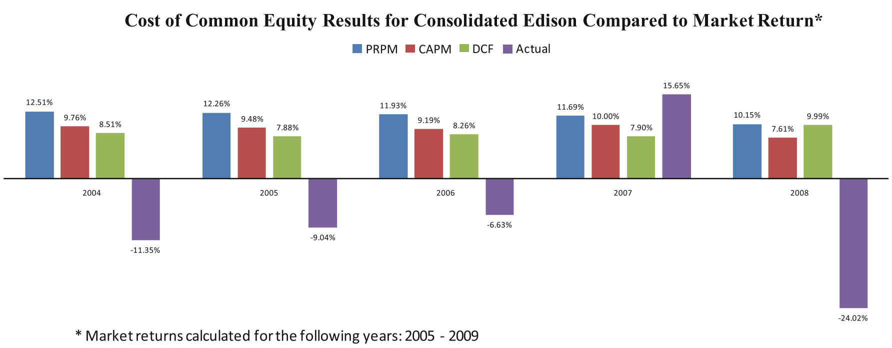
The CAPM was applied by multiplying the Value Line beta (β) available at year-end for each company by the long-term historic arithmetic mean market risk premium ($R_m - R_f$). $R_m - R_f$ is derived as the spread of the total return of large company common stocks over the income return on long-term government bonds from the Ibbotson SBBI 2009 Valuation Yearbook. The resulting company-specific market equity risk premium is then added to a projected consensus estimate of the yield on 30-year U.S. Treasury rate provided by Blue Chip Financial Forecasts as the risk-free rate (R_f) to obtain the CAPM result. This study was also conducted over the 5 years ending 2008.

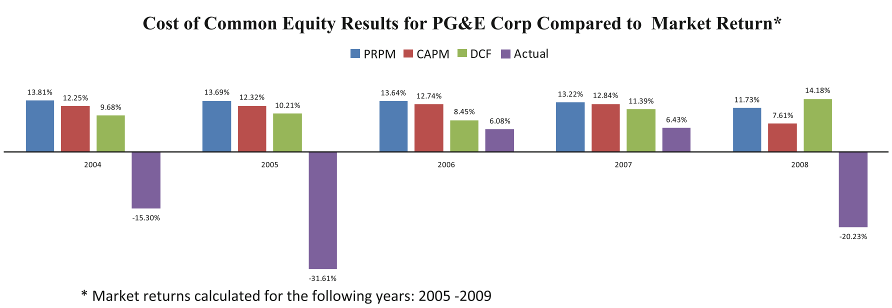
Figures 4–11 show the histograms of the cost of common equity capital estimations for each of the eight public utility stocks and the realized market returns in the forthcoming year. The consumption asset pricing model appears to track more consistently with the CAPM than with the DCF which seems to produce generally lower values than the other methods. The consumption asset pricing model results are similar to the CAPM. The model and the CAPM compete as the best predictor of the rate of return on the book value of common equity (not shown but available upon request), but none of the expected returns were good predictors of market returns. That does not infer that they were not good predictors of *expected* market returns. These results are an initial indicator that the consumption asset pricing model provides reasonable and stable results. This paper does not suggest at this early juncture that the consumption asset pricing model is superior to the CAPM or DCF, although it is based on far less restrictive assumptions than these other models. For example, both the DCF and CAPM assume that markets are efficient. Many assume that the DCF requires that the market-to-book ratio to always equal one, whereas the long-term value for the Standard and Poor's 500 is equal to 2.34. The CAPM assumes that investors demand higher returns for higher volatility and that the minimum required return is the risk-free rate, whereas the consumption asset pricing model allows for investors to require returns less than the risk-free rate for stocks that may have relatively higher volatility but are hedging assets that have desirable return fluctuation patterns that offset downturns in the business cycle. Unlike the CAPM, the model prices the risk to which investors are actually exposed, whether it's systematic risk or not. Some investors are diversified and some are not; the model prices whatever risk to which the aggregate of investors of the specific stock is exposed.

We find that the consumption asset pricing model should be used in combination with other cost of common equity pricing models as additional information in the devel-



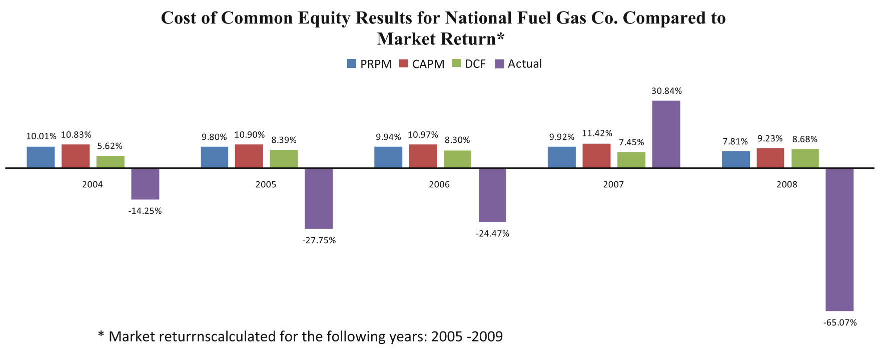


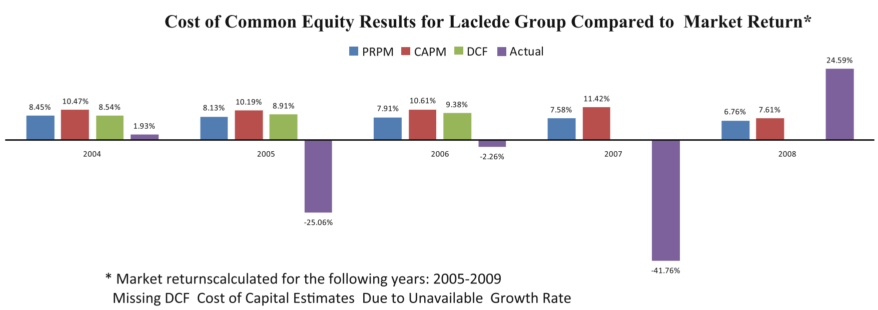


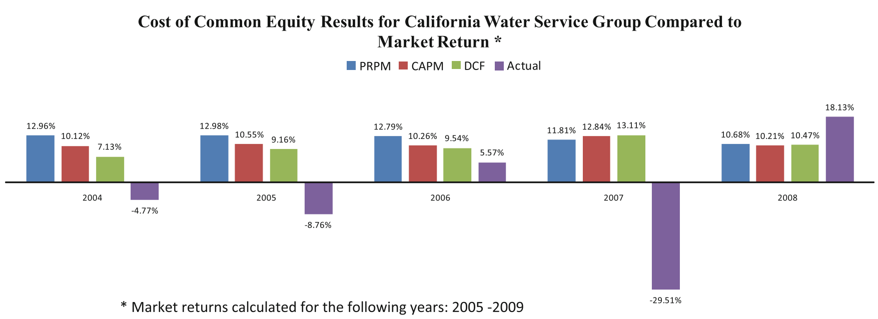


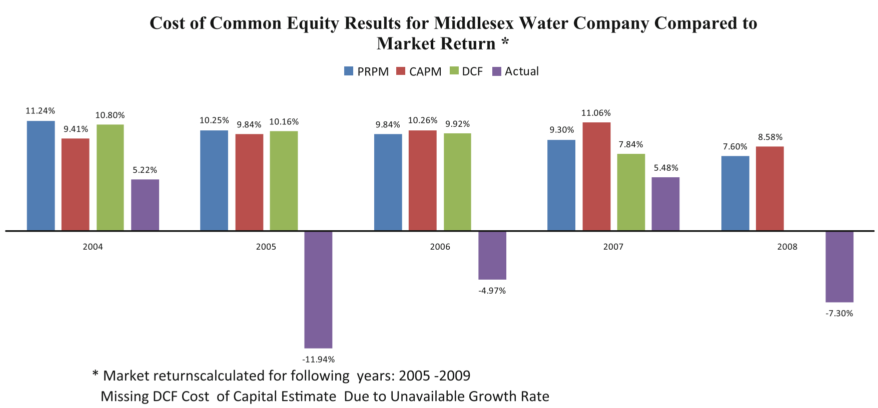
Figs. 4–11 Comparison of the cost of common equity estimates and market

opment of a cost of common equity capital recommendation. Practitioners may find the modeling methods and the use of relatively advanced econometric methods rather cumbersome. The software for performing these estimations is readily available from EViews© and SAS©; two commonly available software packages at utilities, consult-









Figs. 4–11 continued

ing firms and financial firms. Recent Ph.D. and M.S. holding members of research departments of investment and consulting firms have ready access to the model and methods discussed in this paper, although it will require years for these tools, like any "new" technology, to diffuse into standard use. Another problem is that the model requires a substantial time series history on stock returns data to develop stable estimates of risk premia This is problematic especially for the electric and gas utility industries that have consolidated with many mergers in the recent past. This problem can be addressed by developing and predicting the value-weighted risk premium of a portfolio of similar stocks such as electric utilities that have nuclear generating assets. The specific stock in question would be included in the returns index with a weight based on market capitalization that would go to 0 when the stock price history is no longer existent reaching back into the past.

5 Conclusion

The purpose of this paper is to introduce, test empirically and apply a general consumption based asset pricing model that is based on a minimum of assumptions and restrictions that can be used to predict the risk premium to be applied in estimating the cost of common equity for public utilities in regulatory proceedings. The results support the simple consumption-based asset pricing model that predicts the ex ante risk premium with a conditionally predicted volatility in risk premium. The estimates of the cost of common equity from the consumption asset pricing model compare well with rates of return on the book value of common equity and with the CAPM, although both the model and the CAPM results are substantially higher than the DCF. This is quite common in the practice of the cost of common equity in the utility industry. The results of the model are stable and consistent over time. Therefore the model should be considered as it provides additional evidence on the cost of common equity in general and specifically in public utility regulatory proceedings. Secondly, the use of bond-rated yields to predict risk differentiated equity-to-debt risk premia is supported by the empirical evidence and therefore should be applied in estimating the cost of common equity. Finally, the robust empirical evidence on the positive risk-return relationship also shows that utility stocks are not a consumption hedge and are not good hedging securities against contractions in the economy. The model and estimation methodology presented in this paper provide a relatively simple tool to determine whether any asset is a hedge to adverse changes in the business cycle through the level of consumption in the economy.

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Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity

The regulatory process for setting a utility's allowed rate of return on common equity has generally relied upon the Gordon Discounted Cash Flow Model and Capital Asset Pricing Model. The Predictive Risk Premium Model, introduced a year ago, resolves several of the widely known problems with these models. Further testing since its introduction a year ago suggests that it produces stable results which are consistent over time.

Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis and Frank J. Hanley

I. Introduction

The lead article in the July 2008 issue of this *Journal*, "Integrating Renewables into the US Grid: Is it Sustainable," by Professors Peter Mark Jansson and Richard A. Michelfelder,[1] called for the reregulation of the electric utility industry and putting the planning of generation assets, whether renewable or not, back in the hands of the experts and those ultimately responsible for reliability, the electric utilities. During the last 10 years or so,

 1040-6190/$-see front matter http://dx.doi.org/10.1016/j.tej.2013.04.005

states have been backpedaling on deregulation and therefore methods for estimating the cost of common equity and the allowed rate of return have generated new interest as regulating rate of return is not going away as once thought.

The regulatory process for setting a public utility's allowed rate of return on common equity has generally relied upon the familiar Gordon Discounted Cash Flow Model (DCF) and Capital Asset Pricing Model (CAPM). Despite the widely known problems with these models, there has been little initiative to adopt more recently developed asset pricing models with fewer limiting assumptions and requiring less subjective judgment than these traditional models. In December 2011, the article "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities,"[2] published in *The Journal of Regulatory Economics*, introduced the Predictive Risk Premium Model (PRPM). The PRPM trademark refers to a general, yet simple, consumption-based asset pricing model of the risk/return relationship for common stocks which can be used to estimate the cost rate of common equity (ROE). The stability and consistency of the results of PRPM and the ex ante, i.e., expectational, nature of those results indicate that the model should be used to provide additional input into the process of determining an allowed rate of return on common equity for public utilities.

Since publication, more exhaustive empirical testing of the PRPM was conducted for the four utility industry groups which comprise the AUS Utility Reports[3] universe of publicly traded utilities: an electric utility group; a combination electric and natural gas distribution utility group; a natural gas distribution utility group, and a water utility group. The empirical testing confirms the conclusion of the original *Journal of Regulatory Economics* article: the PRPM produces stable results which are consistent over time.

Despite the widely known problems with these models, there has been little initiative to adopt more recently developed asset pricing models with fewer limiting assumptions and requiring less subjective judgment.

II. Development of the PRPM

The cost rate of common equity is not directly observable in the capital markets and must be inferred using various financial models. The most commonly used cost of common equity models in the regulatory arena are the aforementioned DCF and the CAPM. Since these models are based upon many restrictive assumptions, they involve a significant amount of analyst subjectivity in their application, resulting in much debate over the application and results of these models.

The empirical approach to the PRPM is based upon the work of Robert F. Engle, Ph.D.,[4] who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic *time series* with time-varying volatility (*ARCH*),"[5] with "ARCH" standing for autoregressive conditional heteroskedasticity. In other words, volatility (variance) changes over time and is related to itself from one period to the next, especially in financial markets. Engle discovered that the volatility (usually measured by variance) in prices and returns clusters over time. Therefore, volatility is highly predictable and can be used to predict future levels of risk. The theoretical asset pricing model was recently developed in the *Journal of Economics and Business* in December 2011 by Rutgers University professors Richard Michelfelder and Eugene Pilotte.[6]

In this study, the PRPM estimates the risk/return relationship directly using the outcomes of investors' historical pricing decisions and actual long-term U.S. Treasury security yields, with the predicted equity risk premium generated by the prediction of volatility, i.e., the risk, based upon the volatility of past equity risk premiums for the AUS Utility Reports universe of companies.

  http://dx.doi.org/10.1016/j.tej.2013.04.005

III. Estimation Method

The statistical details of the estimation method of the PRPM can be found in the original article in the *Journal of Regulatory Economics*, "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities." Essentially, there are two steps to the application of the PRPM. First, predicted volatility, i.e., risk, is derived based upon previous volatility plus previous prediction error, because volatility is highly predictable and correlated over time. Second, the predicted volatility can then be used to generate the predicted equity risk premium (ERP) by multiplying it by the GARCH coefficient, i.e., the slope of the predicted volatility. A risk-free rate is then added to the ERP to estimate the ROE, i.e., the market based cost of common equity.

IV. Application of the PRPM to Publicly Traded Utility Companies

The PRPM was applied to the companies comprising the AUS Utility Reports' utility industry groups: the electric, combination electric and natural gas distribution, natural gas distribution, and water groups. The PRPM variances were calculated monthly for each individual utility beginning with the first available monthly data included for each individual utility in the University of Chicago Booth School of Business' Center for Research in Security Prices (CRSP) and corresponding monthly long-term U.S. Treasury bond yields from Morningstar's *Ibbotson SBBI – 2012 Valuation Yearbook – Market Results for Stocks, Bonds, Bills and Inflation – 1926–2011 (SBBI)* through 72-month ending periods, i.e., January 2006 through December 2011.

Using EViews Version 7.2, the PRPM coefficients and predicted monthly variances were estimated as described in the *JRE* article for each time series of equity risk premiums. Consistent with the conclusion drawn in the *JRE* article, the predicted equity risk premiums were calculated using the averaged predicted volatilities (variances) over the entire time period for which CRSP data were available for each utility, multiplied by the GARCH, or slope, coefficient generated through EViews for each time series. To calculate the PRPM cost rate of common equity for each utility, the average predicted utility specific equity risk premium through each month ending from January 2006 through December 2011 was then added to the projected consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the next six quarters by the reporting economists in the concurrent *Blue Chip Financial Forecasts (Blue Chip)*.

The DCF was applied in a simple manner, using a dividend yield, D_0/P_0, derived by dividing the month-end indicated dividend per share (D_0) by the month-end closing market price (P_0) for each utility. The dividend yield was then grown by the month-end I/B/E/S consensus five-year projected earnings per share (EPS) growth rate (g) to derive ($D_0\ (1 + g)/P_0$). The one-month predicted dividend yield was then added to the concurrent month's I/B/E/S consensus

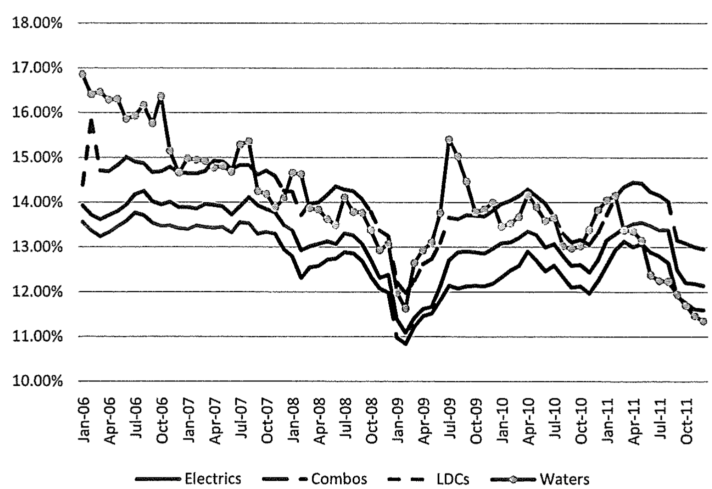

Figure 1: Indicated Return on Common Equity Based upon the PRPM for the AUS Utility Reports Companies

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five-year average projected EPS growth rate to obtain the DCF estimate of the cost of common equity capital, k. The DCF estimates were also calculated for each month from January 2006 through December 2011.

The CAPM was applied by multiplying Value Line Inc.'s beta (β),[7] for each utility, by the long-term historical arithmetic mean market equity risk premium ($R_m - R_f$) through the previous year. ($R_m - R_f$) was derived as the spread of the total return of large company common stocks over the income return on long-term government bonds from the annual *SBBI Valuation Yearbooks* for the years ending 2005 through 2010. The resulting utility-specific equity risk premium was then added to the same projected consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the next six quarters by the reporting economists in the concurrent *Blue Chip* discussed above, to obtain the CAPM estimate of the cost of common equity capital, k. The CAPM estimates were also calculated for each month from January 2006 through December 2011.

Finally, the results for each of the models, the PRPM, DCF, and CAPM, were averaged for each utility group.[8] **Figure 1** presents the average PRPM results for each of the AUS Utility Reports utility groups for each month from January 2006 through December 2011.

Figure 1 shows that indicated ROEs derived from the PRPM were stable for all utility groups until the global financial crisis of 2008–2009. During 2008 and 2009, the PRPM-derived ROEs decline, which in the authors' opinion, was a result of a "flight to quality" by investors, i.e., the willingness of an investor to accept a lower, but more certain, return during financial downturns. Figure 1 also indicates that the PRPM-derived ROEs for the electric, combination electric and natural gas distribution, and natural gas distribution utility groups follow a nearly identical pattern throughout the 72-month period, with the water utility group following a similar, but more volatile pattern.

Figures 2–5 present a comparison of the average PRPM, DCF, and CAPM cost of common equity estimates for each AUS

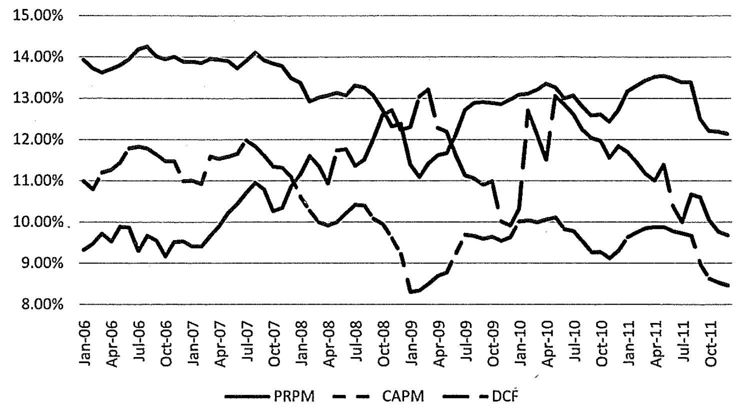

Figure 2: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Electric Companies

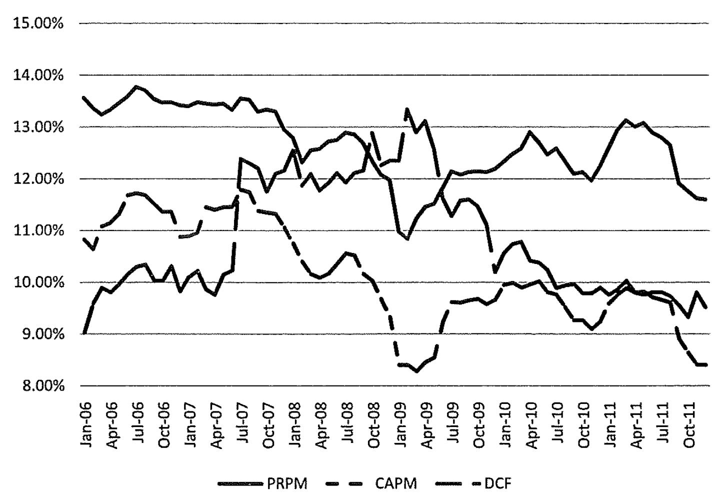

Figure 3: Indicated Return on Common Equity Based upon the PRPM, CAPM, and DCF Methodologies for the AUS Utility Reports Combination Companies

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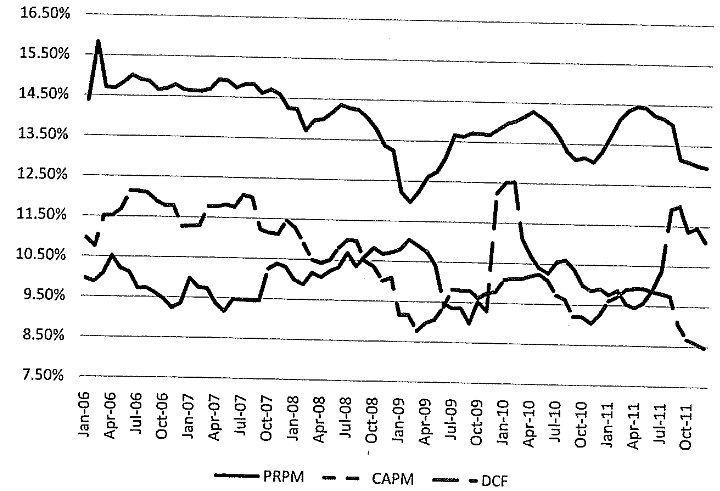

Figure 4: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Gas Companies

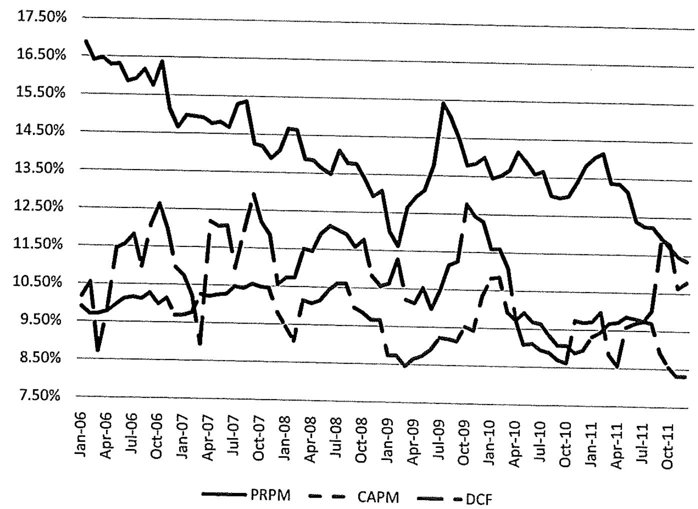

Figure 5: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Water Companies

Utility Reports utility industry group, i.e., the electric utility group; the combination electric and natural gas distribution utility group; the natural gas distribution utility group; and, the water utility group for each month from January 2006 through December 2011.

Figures 2–5 clearly show that, for the most part, the PRPM produces a higher average indicated ROE than both the DCF and CAPM. This is due to the fact that the PRPM prices *all* of the risk that investors actually face collectively. In contrast, the CAPM prices systematic risk (that investors face only if they have a perfectly diversified portfolio, which does not exist) and the DCF uses accounting-based, not market-based, I/B/E/S consensus five-year projected EPS growth rates.

V. Conclusion

In the authors' opinion, the PRPM benefits ratemaking with an additional model to estimate ROE. To that end, the authors have been including the PRPM in their rate-of-return testimonies and the model has been presented publicly in several venues.[9]

Its results are stable and consistent over time. It is not based upon restrictive assumptions, as are the DCF and CAPM. The PRPM is also not based upon an *estimate* of investor behavior, but rather, upon a statistical analysis of *actual* investor behavior by evaluating the results of that behavior, i.e., the volatility (variance) of historical equity risk premiums. In contrast, subjective decisions surround the choice of the inputs to both the DCF and CAPM, from the choice of the time period over which to measure the dividend yield for the DCF, the choice of the DCF growth rate (e.g., historical or projected, earnings per share or dividends per share, and the like), to the selection of the appropriate beta (e.g., adjusted or unadjusted), market equity risk premium (e.g., historical or projected) and the appropriate

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risk-free rate (e.g., historical or projected and/or long vs. short term) for the CAPM. In addition, as previously discussed, the CAPM exclusively prices systematic risk. In contrast, the PRPM prices *all* of the risk actually faced collectively by investors, because the model does not assume that investors' portfolios are perfectly diversified containing no unsystematic risk.

In addition, the inputs to the PRPM are widely available. The GARCH coefficient is calculated with the relatively inexpensive EViews, or other statistical, software, based upon the realized ERP, i.e., total returns minus the risk-free rate. The only subjective decisions to be made when applying the PRPM relate to which risk-free rate to use, e.g., long-term or short-term, and over what time period to estimate the PRPM-derived ROEs.

For all of these reasons, the authors conclude that the PRPM should be considered as appropriate additional evidence to measure the cost of common equity in regulatory rate setting for public utilities.■

Endnotes:

1. Peter Mark Jansson and Richard A. Michelfelder, *Integrating Renewables into the US Grid: Is It Sustainable?* ELEC. J.July 2008, at 9–21.

2. Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, *New Approach to Estimating the Cost of Common Equity Capital for Public Utilities*, J. REG. ECON.(2011) 40, at 261–78.

3. AUS Monthly Utility Reports is a monthly pocket reference book covering the electricity, combination electricity & natural gas distribution, natural gas distribution, and water companies which have publicly traded common stock. The monthly reports provide comprehensive information on key ratios and industry rankings based upon the financial statistics presented in the report.

4. Professor Emeritus, University of California, San Diego, and currently the Michael Armellino Professor in Management of Financial Services at New York University's Stern School of Business.

5. See www.nobelprize.org.

6. Richard Michelfelder and Eugene Pilotte, *Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing*, J. ECON. & BUS.(2011) 63, at 605–37.

7. Using a proprietary data base available at mid-March, June, September, and December at the end of each year, from 2006–2011 from Value Line, Inc.

8. The results shown in the accompanying figures represent AUS Utility group averages of only those utilities in each group for which it was possible to estimate all three models in any given month. For example, if ABC Utility did not have the I/B/E/S consensus growth rate necessary to calculate the DCF in a given month, that utility's PRPM and CAPM were not included in the group average for that month.

9. Edison Electric Institute Cost of Capital Working Group (Webinar Oct. 2012); NARUC Staff Subcommittee on Accounting & Finance (Sept. 2012 and Mar. 2010); National Association of Water Companies Finance/ Accounting/Taxation and Rates & Regulations Committees (Mar. 2012); NARUC Water Committee (Feb. 2012); Wall St. Utility Group (Dec. 2011); IN Utility Regulatory Commission Cost of Capital Task Force (Sept. 2010); Financial Research Inst. of the Univ. of Missouri Hot Topic Hotline Webinar (Dec. 2010); and Center for Research in Regulated Industries Annual Eastern Conference (May 2010 & May 2009).

Subjective decisions surround the choice of the inputs to both the DCF and CAPM.

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Decoupling, risk impacts and the cost of capital

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ABSTRACT

Public utilities and regulators are decoupling revenues from sales to remove a disincentive for utilities to invest in end-use electricity, natural gas and water efficiency. Decoupling is primarily a US ratemaking policy for energy and water utilities as are price caps in Europe. Empirical testing consistently demonstrates that decoupling has no statistically measurable impact on risk and the cost of common equity, yet policy is moving ahead without consideration of that empirical evidence.

1. Introduction

In the late 1970s, US policymakers, legislators, regulators and public utilities began focusing on reducing consumers' demand for energy rather than increasing supply. This was mainly a reaction to the oil supply shock in the US in the early 1970s, beginning with the National Energy Conservation Act of 1978. Europe was already much more efficient in the use of energy by the 1970s as the BTU content of GDP for many European countries was a substantially small fraction relative to the US.

More recently in the US, regulatory policy has required water utilities to encourage the reduction in water use by their consumers. The US and European utility industries seem to observe each other's experiments in decoupling and price caps before adopting such alternative ratemaking policy movements. Price cap regulation, where utility prices are allowed to rise to a cap set by an inflation index minus a total productivity factor offset that reflects potential cost savings, was implemented decades ago for British utilities. Later it was adopted by many other utilities in Europe (EU). However, in the US, very few utilities are under price cap regulation except for telecommunications local exchange carriers. In contrast, decoupling, which effectively disassociates revenue levels from commodity (electric, gas or water) sales has been sweeping across the US in the last two decades for energy and water utilities, while not being adopted in Europe.

Campini and Rondi[1] show that alternative rate mechanisms in the EU have been in the form of price caps to promote efficient investment and operating expenditures without mentioning decoupling. They note that since many utilities in the EU are government owned, there has not been any major adoption of alternative regulatory rate making methods across the utility industry as EU utility rates are not regulated. Therefore, this study is limited to analyzing decoupling in the US, as it is still almost exclusively a regulatory tool implemented in the US.

The profit disincentive associated with revenue and profit reductions is a major financial impediment preventing investor-owned utilities from encouraging the conservation of energy and water usage and sales. In response, various regulatory policy mechanisms have been developed to provide utilities with a financial incentive, or, at least, remove the disincentive, to utilities to encourage energy and water efficiency. One such mechanism is the inclusion of conservation expenditures in rate base so that such expenditures earn a return. Other mechanisms allow for a profit incentive equal to a proportion of the life cycle of net benefits, as well as rate of return premiums for meeting or exceeding conservation goals. Increasingly, revenues are being decoupled from sales volumes so that reductions in sales volumes will

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[1] Campini, C., and L. Rondi. (2010). Incentive regulation and investment: Evidence from European energy utilities. Journal of Regulatory Economics, 38, 1-26.

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potentially stabilize profits rather than reduce them.[2] Decoupling revenues from sales volumes was first implemented in California and New York in the 1980s. Decoupling did not gain momentum outside of California and New York for decades and only recently implemented in various other state regulatory jurisdictions across the US for electric, natural gas, and water public utilities. Fig. 1 is a map depicting the extent of decoupling across the US developed by the National Resources Defense Council[3] . While Fig. 1 shows the extent of decoupling across the US for electricity and natural gas utility industries, it does not show the same for water / wastewater utility industries. Fig. 1 shows that as of August 2018, 26 states have adopted gas decoupling (compared with 20 in 2013) and 17 have adopted electricity decoupling (compared with 14 in 2013).

The types of decoupling generally fall into three categories: fixed and variable rate mechanisms; lost revenue recovery from commodity sales reductions due specifically to energy or water efficiency programs; and fixed revenue true-up mechanisms. Fixed and variable rate mechanisms have a high fixed rate component that may or may not include a set maximum commodity volume included in the fixed rate with the variable rate being the rate for partial or all volume use. The fixed rate is intended to cover all or most fixed costs. Fixed rates are rarely used in the electric or gas utility industries but are frequently used for water utilities. Lost revenue recovery mechanisms allow the utility to collect the revenue lost directly from specific sales reductions due to energy or water efficiency programs. True-up mechanisms set a fixed overall level of revenues with the utility allowed to recover a shortfall in revenues from the fixed level in higher rates. Nadel and Herndon[4] discuss the future of the energy utilities industries and the role that decoupling as a form of alternative ratemaking may play in that future. Also, see Carter[5], Cavanaugh[6], Eto, Stoft, and Belden[7] and the American Council for an Energy Efficient Economy and Natural Resource Defense Council websites for discussion on the trends, theory and implementation of decoupling and various decoupling mechanisms.

One key consideration in many US regulatory rate proceedings and policy discussions is the impact of decoupling on the investment risk of a public utility and, subsequently, its cost of common equity (and therefore the allowed rate of return set by regulators). Since decoupling disassociates revenues from sales volumes, the intended impact is that it generates an increasingly stable and non-declining level of revenues and net income if sales do decline. Therefore, the public utility is expected to be perceived by investors as having lower investment risk, which would lead to a lower cost of common equity capital, that is, the investor required return.

Decoupling can also be viewed as exacerbating investment risk rather than decreasing it. To the extent that investors are concerned about a changing regulatory regime, uncertainty about the measurement of the savings impacts of conservation programs may exacerbate investors' perceived risk and the cost of common equity.

Decoupling is implemented with the intention of reducing or eliminating volume risk and therefore potentially affects the cost of common equity as stated above. If the utility hedges volume risk due to weather, which is the most likely cause of demand shocks to electric, gas or water commodities, hedging derivatives[8] allow the utility to insure such risk. If the utility hedges most of the commodity demand risk while meeting demand regardless of compensation mechanisms, the risk may fall or may not fall depending on the degree of diversification in the investor portfolio. For example, weather risk may or may not affect all common stocks in an investor's portfolio. Should a utility incur costs to hedge risks that do not materialize into an adverse effect, the hedges may not payoff. Therefore, volume risk is not always alleviated with decoupling. Essentially, the question is that although the risk of the business is not changed by reward mechanisms, as demand shocks (positive or negative) still occur, do investors perceive, as do some regulators and utility management, that decoupling reduces risk? While a change in the reward structure does not change the fundamental riskiness of a firm, it is the investors' perceived risk that affects the cost of common equity. While this is not likely to occur in an efficient market, it is not so obvious that financial markets are efficient. The existence of an efficient market is one of a number of assumptions that has been relaxed in the derivation of the recently developed financial model used in this paper. It is commonly known as the predictive risk premium model and technically known as the generalized consumption asset pricing model (GCAPM).[9]

The topic of this paper has been the subject of only a few empirical investigations so far by Wharton and Vilbert[10] and Vilbert, Wharton, Zhang and Hall[11] {collectively referred to as Wharton, et al. (2015, 2016)}. Moody's[12] has estimated the change in business risk and credit metrics due to decoupling, but not the impacts on the cost of capital.

[2] In response to the challenges to achieving the allowed return on common equity due to expected significant capital expenditures to repair and replace utility infrastructure, as well as declining per capita commodity consumption, the National Association of Regulatory Utility Commissioners (NARUC) recommends that regulators carefully consider and implement appropriate ratemaking measures so that water and sewer utilities have a reasonable opportunity to earn their allowed rate of return on common equity. Decoupling, or revenue adjustment stabilization mechanisms (RAM) separate rates / revenues from electricity, gas or water volumes sold. Such mechanisms address the effects of the more efficient use of the commodity and declining per capita consumption, for water, and to a lesser extent, electricity, while maintaining the financial soundness and viability of the utilities. With RAMs, utilities are made whole for revenue shortfalls from allowed revenues used to design rates, which generally result from weather and conservation efforts by customers. RAMs allow for the recovery / crediting of differences between actual and allowed quantity charge revenues. RAMs seem to be effective in mitigating the effects of regulatory lag and improving utilities' opportunities to earn their allowed returns on common equity while upgrading infrastructure, ensuring safe and reliable service, removing the incentive to sell more commodity, and helping to protect valuable natural resources. However, in base rate cases for utilities that have such mechanisms, the question often arises as to whether and to what extent the presence of such mechanisms reduces the utility's investment risk as well and to what extent such a perceived or actual reduction in risk should be reflected in the allowed return on common equity.

[3] National Resources Defense Council. (2018). www.nrdc.org/resources/gas-and-electric-decoupling.

[4] Nadel, S., and G. Herndon. (2014). The future of the utility Industry and the role of energy efficiency. American Council for an Energy Efficient Economy, Report Number U1404.

[5] Carter, S. (2001). Breaking the consumption habit: Ratemaking for efficient resource decisions. Electricity Journal, 14, 66-74.

[6] Cavanaugh, R. (2013). Report: "Decoupling" is transforming the utility industry. Natural Resources Defense Council.

[7] Eto, J., S. Stoft, and T. Belden. (1997). The theory and practice of decoupling utility revenues from sales. Utility Policy, 6, 43-55.

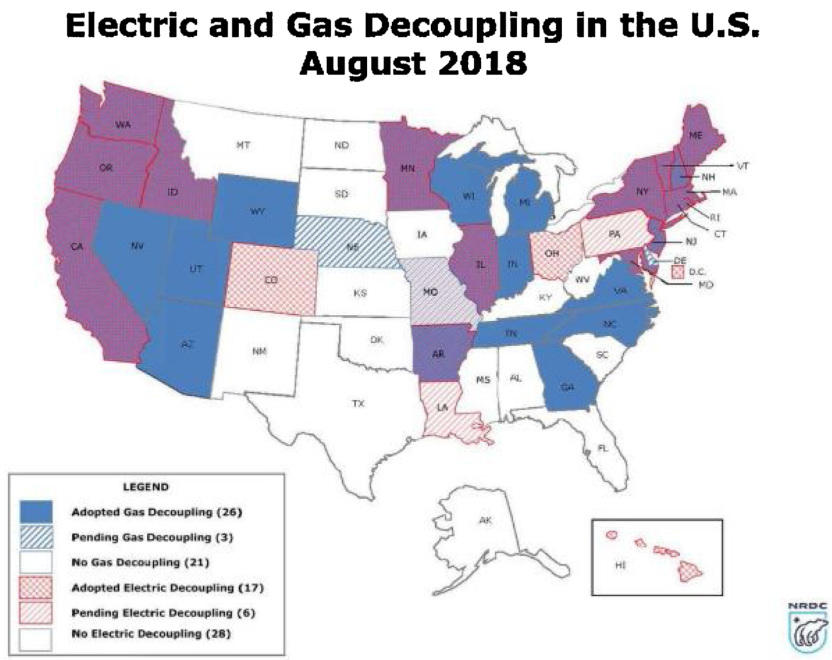
[8] Water derivatives, although not traded in markets as are gas and electricity futures and forwards, are created through private contracts. Some water distribution systems are interconnected to others and have various contracting structures for buying water if a demand shock should cause the need for more water that the incumbent system cannot supply. Some sewer systems have similar contracts to transfer excessive wastewater flows to another utility's treatment plant if their own capacity reaches its limit.

[9] A less technical discussion of this model can be found in "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity Capital," by Richard A. Michelfelder, Pauline Ahern, Dylan D'Ascendis and Frank Hanley, *The Electricity Journal*, 26, 2013.

[10] Wharton, J. and M. Vilbert. (2015). Decoupling and the cost of capital. The Electricity Journal, 28, 19-28.

[11] Vilbert, M., J. Wharton, S. Zhang, and J. Hall. (2016). Effect on the cost of capital of ratemaking that relaxes the linkage between revenue and kwh sales, an updated empirical investigation of the electric industry. A Brattle Group Report.

[12] Moody's Investors Service. (2011). Decoupling and 21st Century Ratemaking. Special Comment.



	2013		2018	
	Utilities	States	Utilities	States
Gas	49	20	64	26
Electric	24	14	41	17
Total	73	25	105	32

Fig. 1. Electric and Gas Decoupling in the U.S. August 2018.
Source: https://www.nrdc.org/resources/gas-and-electric-decoupling, accessed March 31, 2019.

There are no empirical studies on water utilities such as those performed in this study.

Wharton, et al. (2015, 2016) concluded that decoupling has no statistically significant measurable impact on the public utility cost of common equity. They found that while decoupling may reduce revenue volatility, it may not reduce investment risk. In fact, they find that it may actually exacerbate risk as decoupling regulatory policy is viewed as a new and uncertain regime and may be used to promote other regulatory policy goals and create regulatory risk.[13] Reductions in peak loads and the commodity sales impacts of consumer energy or water efficiency measures are difficult and expensive to estimate. This difficulty introduces an additional regulatory risk that may result in exposure to regulatory financial penalties due to the uncertainties associated with such efficiency estimation. Thus, Wharton, et al. (2015, 2016) concluded that on a net basis, decoupling may increase the investment risk of utilities.

Chu and Sappington[14] developed an economic model that investigated under what conditions a utility would provide an economic value maximizing level of energy efficiency services to its consumers. Their investigation is important to our discussion as decoupling is implemented as a tool to incent (or remove the disincentive) utilities to encourage consumers to invest in the optimal level of end-use efficiency resources. In considering the use of decoupling, they found that, generally, decoupling alone is not sufficient to induce utilities to provide the optimal level, that is, enough energy efficiency services. Khazzoom[15],[16] found that one problem is that end-use energy efficiency resources cause a rebound effect whereby lower utility bills cause consumers to increase their energy use as they buy more comfort with their bill savings.

Depending on the specific conditions facing a utility, decoupling may not generate a profit motive for utilities to reduce sales through energy or water efficiency. Utilities could be placed in the position of delivering the predicted amount of energy or water savings expected by regulators but possibly without any profit motive other than the avoidance of regulatory penalties for not meeting a goal. This disincentive has become a major topic relative to alternative ratemaking mechanisms, as the growth in electricity sales is currently less correlated with the growth rate in the US GDP relative to the past, with such sales growing more slowly than the general economy in recent years.[17]

Since the US is widely adopting decoupling (revenue caps) whereas the EU is doing the same with price caps, it is an ongoing natural experiment that allows for comparisons of the consumer value and

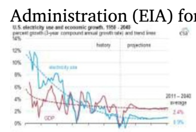
[13] Since multiple types of risk are discussed, we generically define risk as the chance of a disappointment in financial performance.

[14] Chu, L.Y., and D.E.M. Sappington. (2013). Motivating energy suppliers to promote energy conservation. Journal of Regulatory Economics, 49, 227-249.

[15] Khazzoom J.D. (1980). Economic implications of mandated efficiency in standards for household appliances. Energy Journal, 1, 21–39.

[16] Khazzoom J.D. (1987). Energy savings resulting from the adoption of more efficient appliances. Energy Journal, 8, 85–89.

[17] US Energy Information Administration. (2013). Annual Energy Outlook 2013 Early Release US electricity use is expected to experience an annual average growth rate of 0.9% compared with a 2.4% US GDP annual growth rate between 2011 and 2040, according to the US Energy Information Administration (EIA) forecast in 2013, as demonstrated in the EIA graph below:



shareholder value performance between EU price cap utilities and US decoupled utilities. However, since the EU has not adopted decoupling, the data are not available to include EU decoupled utilities in this study.

Since decoupling, as a regulatory policy tool, is being adopted rapidly in the US, Edison Electric Institute, the US electric utility trade association {EEI(2015)}[18] finds that questions arise in regulatory rate proceedings regarding the impacts on the cost of common equity. Due to the importance of this issue and the lack of related literature, we investigate the impact of decoupling on the investor perceived risk of public utilities and resultant cost of common equity.

2. The modeling approach

This paper uses the GCAPM developed by Michelfelder and Pilotte[19] to estimate the impact of decoupling on the public utility cost of common equity[20] . The GCAPM is a financial valuation model recently developed as an alternative to the capital asset pricing model and the dividend discount model for estimating the cost of common equity. Ahern, Hanley, and Michelfelder[21] and as Michelfelder[22] review and apply the GCAPM to estimate public utilities' cost of common equity.

The GCAPM model has fewer restrictions than most financial models. Unlike the CAPM, the GCAPM prices the total risk actually faced by the investor and does not assume that all unsystematic risk is diversified away, which is a key foundation of the standard CAPM.[23] Thus, the priced risk in the GCAPM is based on the level of risk actually faced by the investor, not the risk theoretically imposed by the CAPM. In addition, Fama and French[24] find that the CAPM understates returns and risk, based on a large empirical study of portfolios of common stocks with a continuum of low to high betas. The GCAPM also does not assume or require the efficient markets assumption as does the CAPM.

In the GCAPM, the anticipated risk premium on an asset or common stock depends on the anticipated volatility of that asset's risk premium. The anticipated volatility in the risk premium is driven by current and past risk premia and shocks to the premium. The variances of rates of return are highly correlated with past such variances.

Another property of the model allows us to infer whether decoupling causes a public utility common stock to be a business cycle hedge {Michelfelder and Pilotte (2011)}. This is indicated by the sign of the slope of the risk premium and anticipated volatility. If profits rise or are flat as GDP declines with lower commodity sales and stable revenues, the common stock price could systematically rise when the business cycle is contracting.[25] A public utility with a strong level of decoupling could conceivably experience stable revenues during a contraction in the business cycle. Therefore, utility profits may rise, or at least not fall, when commodity sales fall generated by consumer end-use efficiency and contracting GDP.

To calibrate the GCAPM, we perform a simple test of this property by estimating the model with the risk premium on gold (percent change in the price of gold per troy ounce minus a risk-free rate). Gold is commonly known to be a business cycle and common stock market hedging asset as noted by Hillier, Draper, and Faff[26] . Hillier, Draper, and Faff (2006) show that gold is a common stock market hedge, especially during abnormally high periods of common stock market volatility. Our calibration test results indicate that that the GCAPM model does indeed detect a hedging asset as the slope of the risk premium on its volatility is negative.[27]

The GCAPM can be applied to any asset that is traded in any financial market and therefore can be applied to all traded public utility common stocks. The GCAPM has the added advantage that the decoupling impact on changes in common stock returns as well as the conditional volatility of these returns can be estimated separately within the same model.

Decoupling is expected to lower the variance of the operating cash flows of a public utility due to the increased stability of revenues. The variance of operating cash flows should be driven mainly by the variance of costs[28] Since the volatility of revenues is theoretically equal to zero with decoupling, the covariance of revenues and costs is zero as revenues do not vary, and volatility of *OCF* is purely driven by costs only as $VAR\ (R - C) = VAR\ (C)$.[29] This is essentially the model used by Moody's (2011)[30] which found that utilities with decoupling experienced a reduction in business risk as measured by the change in the standard deviation of the growth rate in gross profit before and after decoupling.

We also estimate changes in systematic investment risk resulting from decoupling by analyzing the change in the short-term (12-month) CAPM beta (β). This short-term beta, a measure of systematic risk, should be more sensitive to regulatory regime changes, such as, for example, decoupling, relative to the standard betas estimated with five years of data typically employed to assess investment risk. Beta is expected to decline with decoupling.[31]

The only other studies on the impact of decoupling on the utility cost of capital, Wharton, et.al. (2015, 2016)[32],[33] estimated the impact of decoupling on the cost of capital for the overall electric and gas utility industries. They also addressed the issue that decoupled subsidiary utilities may represent substantially less than the entire portfolio of assets reflected in the common stock price of a holding company. Using the standard dividend discount model to estimate the cost of common equity portion of their weighted average cost of capital

[18] EEI, Alternative Regulation for Emerging Utility Challenges: 2015 Update.

[19] Michelfelder, R.A., and Eugene A. Pilotte. (2011). Treasury bond risk and return, the implications for the hedging of consumption and lessons for asset pricing. Journal of Economics and Business, 63, 582-604.

[20] The model is based on generalizing variants of intertemporal capital asset pricing models. The literature discussing the development of the model based on more restrictive versions is voluminous and summarized by Michelfelder and Pilotte (2011) and therefore not repeated here.

[21] Ahern, P., F. J. Hanley, and R.A. Michelfelder. (2011). New approach for estimating of cost of common equity capital for public utilities. Journal of Regulatory Economics, 39, 261-278.

[22] Michelfelder, R.A. (2015). Empirical analysis of the generalized consumption asset pricing model: estimating the cost of common equity capital. Journal of Economics and Business, 80, 37-50.

[23] There is no perfect portfolio that removes all idiosyncratic risk as assumed in the development of the CAPM. Unsystematic risk is reduced but not completely mitigated with a highly diversified portfolio and the standard CAPM understates the cost of common equity as it does not price all risk exposure.

[24] Fama, E., and K. French. (2004). The capital asset pricing model: Theory and evidence. Journal of Economic Perspectives, 18, 25-46.

[25] One of the most effective "energy efficiency tools" to generate energy use reduction is a recession. Although the energy-use-US-GDP correlation has declined, it remains substantially positive {EIA (2013), as shown in the figure in footnote 18 above, www.eia.gov/todayinenergy/detail.php?id=10491}.

[26] Hillier, D., P. Draper, and R. Faff. (2006). Do precious metals shine? An investor's perspective. Financial Analysts Journal, 62, 98-106.

[27] All empirical results on gold are available on request.

[28] Operating Cash Flows (*OCF*) is Revenues (*R*) – Cost (*C*), therefore the variance of *OCF* is $VAR\ (R - C) = VAR\ (R) + VAR\ (C) + 2COV\ (R,C)$.

[29] Therefore, in comparing the variance of operating cash flows with and without decoupling, the VAR (*OCF with decoupling*) $= VAR\ (C) < VAR$ (*OCF without decoupling*) $= VAR\ (R) + VAR\ (C) + 2COV\ (R,C)$ as $VAR\ (R) = 0$ and $COV\ (R,C) = 0$ with decoupling and $VAR\ (R) > 0$ and $COV\ (R,C) \neq 0$ without decoupling.

[30] Moody's Investment Services, "Decoupling and 21st Century Ratemaking", Special Comment, November 4, 2011.

[31] Systematic risk is defined as the correlation of an individual common stock's and the market total rates of return

[32] Wharton, J. and M. Vilbert. (2015). Decoupling and the cost of capital. The Electricity Journal, 28, 19-28.

[33] Vilbert, M., J. Wharton, S. Zhang, and J. Hall. (2016). Effect on the cost of capital of ratemaking that relaxes the linkage between revenue and kwh sales, an updated empirical investigation of the electric industry. A Brattle Group Report.

estimates, they regressed this cost of capital on an intensity index of decoupling for each publicly-traded utility common stock to estimate the industry impact. They found no statistically significant impact of decoupling on the cost of capital.

The present study estimates the impact on the cost of common equity of the decoupled firm individually rather than that on an industry as a whole. We use the GCAPM and changes in beta before and after the implementation of decoupling to estimate the impact on risk and the cost of common equity.

3. Methodology

Two versions of the GCAPM model are estimated.[34] Both estimations use a binary variable to reflect the implementation of decoupling for a specific utility with a value of 1 with decoupling and 0 if otherwise.

These results provide separate empirical estimates of the impacts of decoupling on the public utility common stock returns as well as volatility of the returns (risk). As event studies, these and all financial market-based event studies face the question of when the event impacted asset prices, as they can reflect forthcoming events before they are implemented. One example that is relevant for this study is when decoupling implementation was announced in a utility's regulatory decision. We find that using the date of implementation is a conservative approach to estimating the impact as it is most likely the latest date that a decoupling impact would be detected in a common stock price with much of the impact already priced in the asset. However, if a utility's revenues have been decoupled from sales to the extent that revenues are not affected by the business cycle, then the utility's common stock as a hedging asset would be detected in a zero or negative risk-premium-to-volatility slope. Also, if a sufficiently long pre-decoupling time period for observing returns and volatility is available, the change in the post-period should be detected as all of the post-decoupling period returns and volatilities are in a different business risk regime.

4. Data

We perform the empirical work on US utilities only. As discussed in the Introduction, decoupling had not yet been adopted in the EU at the time of this study. The group of US public utility common stocks includes all electric as well as electric and gas combination companies that have 95 % or more of their revenues decoupled and water utility common stocks that have all of their revenues decoupled before 2014. Data for the common stock rates of return are the total monthly rates of return on the common stock of the public utilities from the Center for Research in Security Prices database (CRSP) of the University of Chicago. Data for each public utility common stock include differing pre- and post-decoupling dates and therefore differing rate of return and beta samples. The pre-decoupling data for each common stock include all available past monthly returns data in the CRSP before decoupling for that common stock. Post-decoupling rate of return data for all common stocks end at December 2014 for consistency in the post-decoupling ending period for all utility common stocks. We calculated historical monthly common stock equity risk premiums (monthly common stock returns less the monthly yields on long-term U.S. Treasury Bonds for the selected publicly traded water utilities using common stock returns data from the CRSP database and Morningstar (2015) SBBI® 2015 Market Results for Stocks, Bonds, Bill and Inflation 1926–2015[35] and the Federal Reserve Statistical Release H.15 for long-term Treasury bond yields. The CAPM beta data include all short-term betas available for each public utility common stock that has been decoupled in the CRSP database and ends at 2014. They are available on an annual basis. The CAPM short-term beta is a one-year estimate of beta that approximately involves regressing daily rates of return on the public utility common stock on a market index as shown footnote 31. The standard beta available from financial firm databases such as Value Line Investment Survey or CRSP are 5-year betas based on regressing monthly or weekly common stock rates of return for the past 5 years on a market index. We find that the longer-term beta would be less sensitive to regime changes in risk such as decoupling. We restrict the sample of pre- and post-decoupling betas for each common stock so that the number of beta observations are the same before and after decoupling.

Since the number of data observations has different times series of ranges for each public utility common stock and decoupling occurred on different dates for most utilities, we have developed Table 1 to show each public utility common stock's data date range, that is, the dates and number of risk premium (rate of return minus risk-free rate) observations used to estimate the GCAPM and the total number of betas used for the pre- and post beta comparison. Table 1 also has the date of decoupling for each public utility.

5. Results and discussion

Table 2 presents the public utility common stocks in the study and the empirical results of the GCAPM estimates. The risk-premium-to-volatility slopes re shown along with the decoupling slope in the risk-premium and volatility equations for each electric, electric and gas combination, and water utility common stocks. The decoupling slope in the risk-premium equation will be negative (positive) if the risk premium should decline (rise) and decoupling creates a reduction (increase) in business risk. None of these slope estimates are statistically significant. The decoupling slope in the volatility equation should be negative (positive) if decoupling caused a reduction (increase) in the volatility of the profit of the utilities. Two of the slopes are negative and significant at $p = 0.10$, yet the magnitudes of the slopes are very small.

All of the return-volatility slopes, except for one of the energy utilities are positive and significant, yet none in the water utility group are significant. These results indicate that the energy utility common stocks are not business cycle hedging assets and that their profits are synchronized with the business cycle. The results for the water group may indicate that they are business cycle hedging assets as none are statistically significant. The zero value for the water utility slopes imply that there is no relation between water utility rates of return and the business cycle. Water utility profits are not correlated with the business cycle even in the absence of decoupling. Also, water usage attrition is occurring across the US as households (water consumption per household is declining) due to the use of water-efficient appliances (such as low-flow faucets, showerheads and efficient toilets) and the change per capita water use behaviors to conserve water.

Table 3 presents the pre- and post-decoupling changes in the systematic risk as represented by the short-term CAPM beta for all of the public utility common stocks. Although, the betas drop after the implementation of decoupling, none of the changes in beta are statistically significant using a t-statistic at a $p = 0.05$. Additionally, the standard errors of the betas (σ_{pre} and σ_{post}) show no consistent pattern of increasing or decreasing after decoupling.

Our results do not show any statistically significant impacts of decoupling on the cost of common equity and risk. Therefore, we find no evidence to conclude that decoupling affects investor perceived risk or the cost of common equity. While electric and gas public utility common stocks were not found to be business cycle hedges, we do find that water utility common stocks may be business cycle hedges, or more likely, water usage and revenue simply have no relation with GDP.

Our results are based on the moderate amount of data available to date. Although we would obviously prefer more data than are available

[34] Specifications available on request.

[35] Morningstar® SBBI®. (2015). Market Results for Stocks, Bonds, Bills, and Inflation 1926 - 2014, Appendix A Tables.

Table 1
Data Description for Risk Premiums and Betas.

Electric, Elec. & Gas Comb. Utility	Effective Decoupling Date	Beginning of Measurement Period Returns Data	Total # of Months Return Data	Total Number of Pre- and Post- Annual Beta Observations
Consolidated Edison	10/2007	07/30/02	126	10
Pacific Gas & Electric	01/1983	01/31/53	720	60
Edison International	01/1983	01/31/53	720	60
CH Energy Group	07/2009	01/31/06	84	6
CMS Energy Corp.	05/2010	9/30/07	64	6
Hawaii Electric	12/2010	11/30/08	50	5
Portland General Electric	12/2010	11/30/08	50	6
Idaho Power	03/2007	05/30/01	140	12
Water Utility				
American States Water	1/2002	6/2002	153	12
California Water	1/2009	10/2001	162	12
Connecticut Water	7/2008	10/2002	150	10
Artesian Resources	11/2008	6/1996	226	12

Table 2
GCAPM Estimation Results.

Electric, Elec. & Gas Comb. Utility	Risk premium to volatility slope	Change in risk premium to volatility slope with decoupling	Decoupling Impact on Volatility Decoupling
Consolidated Edison	1.460***	0.004	–0.000
Pacific Gas & Electric	1.781***	0.001	–0.001
Edison International	1.379***	0.003	0.000
CH Energy Group	2.094***	0.004	–0.000
CMS Energy Corp.	1.440***	0.011	–0.000
Hawaii Electric	1.607***	0.004	–0.000*
Portland General Electric	0.461	0.010	–0.000
Idaho Power	1.939***	0.003	–0.000
Water Utility			
American States Water	0.596	0.011	0.000
California Water	0.525	0.004	–0.000
Connecticut Water	–1.008	0.009	0.000
Artesian Resources	3.006	–0.004	–0.002*

Table 3
Changes in Systematic Risk from Decoupling.[a]

Electric, Elec. & Gas Comb. Utility	Mean β_{PRE}	Mean β_{POST}	σ (β_{PRE})	σ (β_{POST})	t-Statistic
Consolidated Edison	0.608	0.427	0.172	0.064	–1.329
Pacific Gas & Electric	0.522	0.535	0.174	0.373	0.112
Edison International	0.588	0.582	0.199	0.294	–0.051
CH Energy Group	0.680	0.401	0.279	0.326	–0.759
CMS Energy Corp.	0.758	0.559	0.198	0.140	–0.815
Hawaii Electric	0.619	0.570	0.253	0.155	–0.171
Portland General Electric	0.637	0.658	0.069	0.052	–0.151
Idaho Power	0.905	0.728	0.251	0.125	–0.818
Mean	0.670	0.560			
Water Utility					
American States Water	0.975	0.623	0.535	0.279	–1.430
California Water	1.192	0.520	0.544	0.257	–2.735***
Connecticut Water	0.664	0.502	0.235	0.176	–1.232
Artesian Resources	0.075	0.146	0.100	0.161	0.909
Mean	0.434	0.475			

[a] Beta is the annual year-ending beta from the CRSP database. The data timeframe is different for each utility with an equal number of annual pre- and post-decoupling beta data observations for the specific stock in the CSRP database and ends in 2014. Each single beta was estimated with one year of daily rate of return data. See Table 1 and footnote 32. ***, **, * refers to statistical significance at 0.01, 0.05, and 0.10 respectively.

at this juncture, there is no time to wait for a larger volume of data as regulators and utilities have been and are implementing policy now as if decoupling does reduce business risk and, thus, the costs of capital without any evidence that it does. This paper serves as an early warning signal, albeit with the limited evidence that is available.

6. Conclusion and policy implications

We conclude that decoupling has no statistically measurable impact on the cost of common equity or business risk based on our empirical analysis for electric, electric and gas, and water utility common stocks. Some researchers may view this result as a "non-result." This is an important finding as it is consistent with the empirical findings of Vilbert, et al. It is also important for policy globally as decoupling is considered as a potential reducer to risk and the cost of common equity by regulators and public utilities in the US based on intuition, without any empirical evidence.

Moody's (2011) finds a reduction in business risk as measured by the change in the variability of gross profit after decoupling but did not estimate the impact on the cost of common equity. Moody's (2011) did find that electric utilities were somewhat reluctant to adopt decoupling as electric utility executives anticipated that growth in sales would return after the steep recession that ended with the business cycle trough in June 2009 as identified by the National Bureau of Economic Research[36] . Since the US business cycle expansion post-June 2009, electricity sales have remained almost flat, which may have caused the change in sentiment toward decoupling by electric utility executives. Growth in a utility's commodity sales above the level used to design regulated rates would increase the profit and rate of return on common equity. The US investor-owned electric utility industry also expected that the adoption of decoupling would cause state public utility regulators to reduce their allowed rate of return under the notion that it reduces risk. Moody's (2011) was written soon after the recession had ended, but the anticipated growth in sales has not materialized after more than ten years into the US business cycle expansion. A few years after the Moody's (2011) study, in a more recent report, the EEI found a change in sentiment {EEI (2015)} that electric utilities favor decoupling and that it has become more widespread across the US.

Although we conclude that decoupling has no statistically significant impact on investor perceived risk and the cost of common equity, this does not mean necessarily that decoupling has no impact on the perceived risk and the cost of common equity of public utilities. We find that it cannot be isolated and estimated, given the many other factors affecting investor perceived risk. For many electric utilities, some current major risk drivers are flat or declining sales from customer-owned solar projects and energy efficiency resources; the

[36] National Bureau of Economic Research. (2018). NBER.org.

requirement to buy back excess customer generated electric from renewable resources at full retail rates (net metering); increasing requirements in the proportion of a utility's sales that have to be generated from renewable energy, causing larger purchases of renewable energy credits (known as renewable portfolio standards that have been adopted by many states and across Europe); increasingly stringent environmental regulations on coal plants; and the impact of falling and low natural gas prices on the competitiveness of existing coal and nuclear plants.

For water utilities, we find their common stocks to be moderate business cycle hedges (no correlation with the business cycle rather than a strong negatively correlated hedge). Since water utility sales are declining on a per capita basis and unassociated with the business cycle, decoupling may provide financial protection if water revenues decline. To the extent that there is positive growth in the number of water utility customers that offsets the declining per capita consumption, total revenues and sales may not be falling. The impact of decoupling on water utility investment risk and cost of common equity was not able to be detected in this study. This is the first study on decoupling in the water utility industry and provides an area for future research.

Another explanation for the lack of detection of a change in risk or the cost of common equity from decoupling is that risk may be created with the implementation of decoupling and the net impact may not be clear as an increase or decrease in risk as Vilbert, et al. They find that the implementation of decoupling is a new and alternative regulatory regime that may be a new source of regulatory risk for the utility. Finally, as discussed in detail in the Introduction above, volume risk, that is, the fundamental nature of the business and business risk, is not alleviated by changing the reward mechanism, and attempts to do so may increase risk and the cost of common equity. The point is that there are cogent theoretical and practical bases to expect that decoupling increases or decreases risk, so it is problematic to develop an *a priori* hypothesis to test a one-way directional impact of risk and return from decoupling.

Therefore, we do not recommend that public utility regulators in the US or elsewhere reduce common equity cost rates in the presence of decoupling mechanisms based on the assumption of reduced risk. The impact is *de minimis* and not statistically significant amongst all of the other investor perceived risk factors affecting the market prices of public utility common stocks. While an alternative research approach may attempt to isolate the impacts of other individual risk factors on the cost of common equity and risk, making for a long regression equation, we cannot detect a statistically significant signal of decoupling on the cost of common equity or volatility. As a contrast, for example, the risk and cost of common equity impact of owning nuclear power generation assets (versus no nuclear assets) has a measurable impact on investors' returns, risk and cost of common equity without attempting to isolate the myriad of other risk variable impacts. Decoupling as a regulatory policy mechanism to encourage public utilities to provide resources and funding to their consumers to conserve electricity, natural gas, and water (therefore also wastewater flows) has no *measurable* impact on the investment risk and the cost of common equity (either up or down). As a policy prescription, public utility regulators should not adjust the allowed rate of return which affects the public utility's rates as a spillover impact of using decoupling to promote environmental policy.

Finally, the US may be further ahead in adopting rate mechanisms that address energy and water efficiency due to its long-term lag relative to Europe in the efficient use of energy and water and the recent "necessity-is-the-mother-of-invention" US driver of energy and water efficiency. European and other global regulators should proceed slowly in adopting decoupling and assuming that decoupling reduces risk as there is no empirical evidence to date that it does.

An extension of this research could evaluate risk premiums or discounts in bond yields as there are many more investor-owned utilities which have outstanding bonds relative to those that have their own publicly traded common stock due to consolidation in the utility industry in the US. For example, Exelon is the holding company of six utilities whose stocks were publicly traded on the New York Stock Exchange. They are Atlantic City Electric, Baltimore Gas and Electric, Commonwealth Edison, Delmarva Power and Light, Philadelphia Electric and Potomac Edison Power. Another future extension could focus on decoupling when some EU investor-owned utilities and regulators, inevitably, adopt decoupling should it prove to substantially encourage more conservation in the US. An investigation of hedging costs and savings, risk impacts, and effects on profits with and without decoupling may shed more light on the topic. More research is also needed on water decoupling as this is the first study known to date on the topic involving cost of capital and risk. Lastly, a comparison that separates consumer and shareholder value creation and investigating the impacts on conservation from price and revenue caps is another extension of this paper for future research.

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Decoupling impact and public utility conservation investment

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ABSTRACT

Public utilities and regulators are implementing various forms of regulatory mechanisms that decouple revenues from commodity sales to remove a disincentive or create an incentive for utilities to invest in and encourage consumers to conserve electricity, natural gas and water. A major question is whether such regulatory mechanisms affect investor-perceived risk, the cost of common equity and the utility rates of such commodities. This is an important question as regulators in the US are and have been considering the impact of decoupling on investment risk and therefore the cost of common equity in rate proceedings. This matter is also important for regulators globally as they consider decoupling as a policy initiative in setting rates and rate of return. Currently, decoupling is primarily a US ratemaking policy for energy and water utilities as are price caps in Europe. Empirical testing, based on the available data in the US, consistently demonstrates that decoupling has no statistically measurable impact on risk and the cost of common equity. Therefore, at this juncture, policy is moving ahead, at least in the US, without empirical evidence on whether it does have impact on risk and return.

1. Introduction

Beginning in the late 1970s, US policymakers, legislators, regulators and public utilities began to focus on reducing consumers' demand for energy rather than increasing supply. This was mainly a reaction to the oil supply shock in the US in the early 1970s, which began with the National Energy Conservation Act of 1978. Europe was already much more efficient in the use of energy by the 1970s as the BTU content of GDP of many European countries was a substantially small fraction relative to the US.

More recently in the US, regulatory policy has required water utilities to encourage the reduction in water use by their consumers. The US and European utility industries seem to observe each other's experiments in decoupling and price caps before adopting such alternative ratemaking policy movements. Price cap regulation, where utility prices are allowed to rise to a cap set by an inflation index minus a total factor productivity offset that reflects potential cost savings (known as $RPI - X$), was implemented decades ago for British utilities. Only afterward was it adopted by many other utilities in Europe (EU). However, it has largely not been adopted in the US as very few utilities are under price cap regulation except for telecommunications local exchange carriers. On the other hand, decoupling, which effectively disassociates revenue levels from commodity (electric, gas or water) sales has been sweeping across the US in the last two decades for energy and water utilities, while being not adopted in Europe.

Campini and Rondi (2010) show that alternative rate mechanisms in the EU have been in the form of price caps to promote efficient investment and operating expenditures. There is no mention in that article of decoupling. They also point out that since many utilities in the EU are government owned there has not been any major adoption of alternative regulatory rate making methods across the utility industry as government utility rates are not regulated. Therefore, this study is limited to analyzing decoupling in the US, as it is still almost exclusively a regulatory tool implemented in the US.

A major financial impediment preventing investor-owned utilities from encouraging conservation of energy and water usage and sales is the profit disincentive associated with subsequent revenue and profit reductions. Therefore, various regulatory policy mechanisms have been developed to provide utilities with a financial incentive, or, at least, remove the disincentive to utilities to encourage energy and water efficiency. Some mechanisms have been the inclusion of conservation expenditures in rate base so the such expenditures earn a return. Other mechanisms allow for a profit incentive equal to a proportion of the life cycle of net benefits, as well as rate of return premiums for meeting or exceeding conservation goals. Increasingly, revenues are being decoupled from sales volumes so that reductions in sales volumes will

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potentially stabilize profits rather than reduce them.[1] Decoupling revenues from sales volumes was first implemented in California in 1982 and in New York in the 1980s. Although decoupling did not gain momentum outside of California and New York for decades afterward, it has recently been implemented in various state regulatory jurisdictions across the US for electric, natural gas, and water public utilities. Fig. 1 is a map depicting the extent of decoupling across the US developed by the National Resources Defense Council (2018). Although it shows the extent of decoupling across the US for electricity and natural gas utility industries, it does not show the same for water/wastewater utility industries. Fig. 1 shows that as of August 2018, 26 states have adopted gas decoupling (compared with 20 in 2013) and 17 have adopted electricity decoupling (compared with 14 in 2013).

The types of decoupling generally fall into three categories: fixed and variable mechanisms, lost revenue recovery from commodity sales reductions due specifically to energy or water efficiency programs, and fixed revenue true-up mechanisms. Fixed and variable rate mechanisms have a high fixed rate component that may or may not include a set maximum volume of the commodity included in the fixed rate and the variable component is the rate for partial or all volume use. The fixed rate is meant to cover all or most fixed costs. They are rarely used in the electric or gas utility industries but are frequently used for water utilities. Lost revenue recovery mechanisms allow the utility to collect the revenue lost directly from the specific sales reductions due to energy or water efficiency programs. True-up mechanisms set a fixed overall level of revenues and the utility can recover a shortfall in revenues from the set level in higher rates. Nadel and Herndon (2014) discuss the future of the energy utilities industries and the role that decoupling as a form of alternative ratemaking may play in that future. Also, see Carter (2001), Cavanaugh (2013), Eto et al. (1997) and the American Council for an Energy Efficient Economy and Natural Resource Defense Council websites for discussion on the trends, theory and implementation of decoupling and various decoupling mechanisms.

One key consideration in many US rate proceedings and policy discussions is the impact of decoupling on the investment risk of a public utility and its cost of common equity (and therefore the allowed rate of return set by regulators). Since decoupling disassociates revenues with sales volumes, the intended impact is that it generates an increasingly stable and non-declining level of revenues and net income if sales do decline. Therefore, the public utility is expected to be perceived by investors as having lower investment risk, which would lead to a lower cost of common equity capital, i.e., the investor required return.

Decoupling can also be viewed as exacerbating investment risk rather than decreasing it. To the extent that investors are concerned about a changing regulatory regime, uncertainty about the measurement of the savings impacts of conservation programs, partially implemented or gamed mechanisms, to name a few potential issues associated with such an alternative ratemaking mechanism, may exacerbate investors' perceived risk and the cost of common equity.

Decoupling is implemented with the intention to reduce or eliminate volume risk and therefore potentially the cost of common equity as stated above. If the utility hedges volume risk due to weather, which is the most likely cause of demand shocks to electric, gas or water commodities, hedging derivatives[2] allow the utility to insure such risk. If the utility hedges most of the commodity demand risk while meeting demand regardless of compensation mechanisms, the risk may fall if the volume risk is systematic. Whether such weather risk is systematic or not is questionable as weather shocks do not affect most common stocks in a highly diversified portfolio nor the business cycle that drives the systematic risk of a market portfolio. It may not be systematic even within a utility-only portfolio as weather patterns can be diversified away with geographical diversification. If weather happens to have a systematic effect on the risk of the public utility common stock, it is conceivable that cost-effective hedges may reduce risk and the cost of common equity. Should the utility hedge risks that do not materialize into an adverse effect such as a demand shock, they incur costs to do so, and the hedges do not payoff. That is, they spend too much on hedged positions or insurance or take title to commodity that they cannot sell, such as with a take-or-pay contract, thus facing increased risk, costs and higher costs of common equity. Therefore, volume risk is not actually alleviated with decoupling. Essentially, the question is that although the risk of the business is not changed by reward mechanisms, as demand shocks (positive or negative) still occur, do investors perceive, as do some regulators and utility management, that decoupling reduces risk? A change in the reward structure does not change the fundamental riskiness of a firm. It is the investors' perceived risk that affects the cost of common equity. This would not seem to occur in an efficient market, but it is not so obvious that financial markets are efficient.

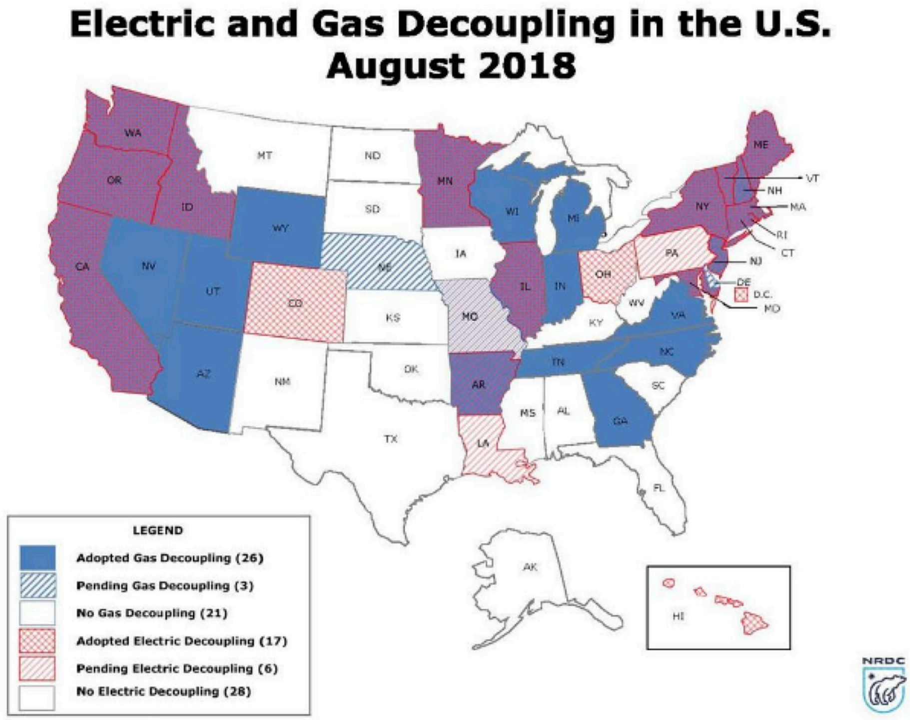
An efficient market is one of a number of assumptions that has been relaxed in the derivation of the generalized consumption asset model (GCAPM) used in this paper. As one example of inefficiency, cash flows generate the fundamental value of a firm, yet the best predictor of common stock prices statistically is earnings per share growth rates, not cash flow per share growth. Investors seem to erroneously price common stocks with earnings, not cash flow based on their perceptions of what affects common equity financial value.

The topic of this paper has been the subject of only a few empirical investigations so far by Wharton and Vilbert (2015) and Vilbert et al. (2016). Moody's (2011) has estimated the change in business risk and credit metrics due to decoupling, but not the impacts on the cost of capital. There are no empirical studies on water utilities such as those performed herein.

Wharton and Vilbert (2015) developed an index of decoupling exposure for public utility and utility holding company common stocks and estimated the after-tax weighted average cost of capital (ATWACC) using the dividend discount model to estimate the cost of common equity. They regressed the ATWACC on an index of decoupling intensity for each public utility in their sample and observed the slope to

[1] In response to the challenges to achieving the allowed return on common equity due to expected significant capital expenditures to repair and replace utility infrastructure, as well as declining per capita commodity consumption, the National Association of Regulatory Utility Commissioners (NARUC) recommends that regulators carefully consider and implement appropriate ratemaking measures so that water and sewer utilities have a reasonable opportunity to earn their allowed rate of return on common equity. Decoupling, or revenue adjustment stabilization mechanisms (RAM) separate rates/revenues from electricity, gas or water volumes sold. Such mechanisms address the effects of the more efficient use of the commodity and declining per capita consumption, for water, and to a lesser extent, electricity, while maintaining the financial soundness and viability of the utilities. With RAMs, utilities are made whole for revenue shortfalls from allowed revenues used to design rates, which generally result from weather and conservation efforts by customers. RAMs allow for the recovery/crediting of differences between actual and allowed quantity charge revenues. RAMs seem to be effective in mitigating the effects of regulatory lag and improving utilities' opportunities to earn their allowed returns on common equity while upgrading infrastructure, ensuring safe and reliable service, removing the incentive to sell more commodity, and helping to protect valuable natural resources. However, in base rate cases for utilities that have such mechanisms, the question often arises as to whether and to what extent the presence of such mechanisms reduces the utility's investment risk as well and to what extent such a perceived or actual reduction in risk should be reflected in the allowed return on common equity.

[2] Water derivatives, although not traded in markets as are gas and electricity futures and forwards, are created through private contracts. Some water distribution systems are interconnected to others and have various contracting structures for buying water if a demand shock should cause the need for more water that the incumbent system cannot supply. Some sewer systems have similar contracts to transfer excessive wastewater flows to another utility's treatment plant if their own capacity reaches its limit.



	2013		2018	
	Utilities	States	Utilities	States
Gas	49	20	64	26
Electric	24	14	41	17
Total	73	25	105	32

Fig. 1. Trend in Energy Utility Decoupling in the US. Source: https://www.nrdc.org/resources/gas-and-electric-decoupling, accessed March 31, 2019

estimate the impact. Although the slope of the regression is negative, it is not statistically significant. They concluded that decoupling has no statistically significant measurable impact on the public utility cost of common equity. They found that decoupling may reduce revenue volatility, but it may not reduce investment risk. They find that it may actually exacerbate risk as decoupling regulatory policy is viewed as a new and uncertain regime and may be used to promote other regulatory policy goals and create regulatory risk.[3]

Reductions in peak loads and the commodity sales impacts of consumer energy or water efficiency measures are difficult and expensive to estimate. This difficulty introduces an additional regulatory risk that may result in exposure to regulatory financial penalties due to the uncertainties associated with such efficiency estimation. Thus, Wharton and Vilbert (2015) concluded that on a net basis, decoupling may increase the investment risk of utilities.

Chu and Sappington (2013) developed a social welfare model that investigated under what conditions a utility would provide a welfare maximizing level of energy efficiency services to its consumers. Their investigation is important to our discussion as decoupling is implemented as a tool to incent utilities to encourage consumers to invest in the optimal level of end-use efficiency resources. In considering the use of decoupling, Chu and Sappington (2013) found that, generally, decoupling alone is not sufficient to induce utilities to provide the socially optimal level, that is, enough energy efficiency services. One problem is that end-use energy efficiency resources cause a rebound effect {Khazzoom (1980, 1987)} whereby lower utility bills cause consumers to increase their energy use as they buy more comfort with the savings.

Chu and Sappington (2013) also discuss that, if the price of electricity is above the private marginal cost (in contrast to social marginal cost), falling sales reduce the utility's profits.[4] Since public utility ratemaking uses average cost to set rates, this is a highly unlikely occurrence to find price above marginal cost. Depending on the specific conditions facing a utility, decoupling may not generate a profit motive for utilities to reduce sales through energy or water efficiency. Utilities could be placed into the position of delivering the predicted amount of energy savings expected by regulators but possibly without any profit motive other than the avoidance of regulatory penalties for not meeting a goal. This disincentive has become a major topic relative to alternative ratemaking mechanisms, as the growth in electricity sales is less correlated with the growth rate in the US GDP relative to the past, with such sales growing more slowly than the general economy has been in recent years.[5]

Brennan (2010) developed a social welfare model to derive conditions under which utilities would be incented to provide energy efficiency services, showing that decoupling must separate revenues from the generation of electricity and not just revenues and sales from the

[3] Since multiple types of risk are discussed, we generically define risk as the chance of a disappointment in financial performance.

[4] The key problem with the over-use of utility services is that public utility pricing is based on average versus marginal cost pricing. Utility services have an excess demand (over-consumed) and end-use efficiency resources have an excess supply (under-consumed) with general equilibrium not attained. The authors of this study are hard-pressed to find where the actual price of electricity is above private marginal cost.

[5] US electricity use is expected to experience an annual average growth rate of 0.9% compared with a 2.4% US GDP annual growth rate between 2011 and 2040, according to the US Energy Information Administration (EIA) forecast in 2013, as demonstrated in the EIA graph below.

distribution of electricity, leading to a highly complex form of electricity pricing regulation, rather than just the simpler separation of sales to the consumer and the related revenues collected. Brennan (2010a) compared incentive regulation using price caps versus decoupling. His paper analyzed the difference between separating profits from management decision-making and incentive-based regulation in the form of price caps which are meant to promote better input decision-making than rate of return regulation that provides an opportunity to earn a set rate of return, somewhat regardless of the outcomes of input choice decision-making. Brennan (2010a) concluded that utilities will encourage energy savings or more usage under price caps depending upon whether the price is below or above marginal cost, respectively.

Since the US is widely adopting decoupling (revenue caps) whereas the EU is doing the same with price caps, it is an ongoing natural experiment that allows for comparisons of the consumer surplus and shareholder value performance (collectively, social welfare) from EU price cap utilities and US decoupled utilities. Since the EU has adopted price caps and US has adopted decoupling, the data are not available to include EU decoupled utilities in this investigation.

Since decoupling, as a regulatory policy tool, is being adopted rapidly in the US {Edison Electric Institute, the US electric utility trade association, EEI (2015)}, questions arise in rate proceedings regarding the impacts on the cost of common equity. Due to the importance of this issue and the lack of related literature, we investigate the impact of decoupling on the investor perceived risk of public utilities and resultant cost of common equity. The next section discusses the models that are the basis of the analysis. Section 3 discusses the empirical methodology. Section 4 describes the data. Section 5 discusses the results and Section 6 provides concluding remarks, policy recommendations and areas for future research.

2. The modeling approach

This paper uses the GCAPM developed by Michelfelder and Pilotte (2011) to estimate the impact of decoupling on the public utility cost of common equity. The model is based on generalizing variants of intertemporal capital asset pricing models. The literature discussing the development of the model based on more restrictive versions is voluminous and summarized by Michelfelder and Pilotte (2011) and therefore not repeated here. The GCAPM was empirically applied by Michelfelder and Pilotte (2011) to the full spectrum of assets on the US Treasury yield curve. The GCAPM is a financial valuation model recently developed as an alternative to the CAPM and the dividend discount model for estimating the cost of common equity. Ahern et al. (2011) and as Michelfelder (2015) review and apply the GCAPM to estimate public utilities' cost of common equity.

The GCAPM model has the following characteristics. It does not have restrictions on the coefficient of risk aversion in investors' utility function as do most models. It allows for a negative relation between the rate of return and volatility.[6] This relation will occur for assets with prices that move in the opposite direction of the business cycle. Unlike the CAPM, the GCAPM prices the total risk actually faced by the investor and does not assume that all unsystematic risk is diversified away, which is a key foundation of the standard CAPM. There is no perfect portfolio that removes all idiosyncratic risk as assumed in the development of the CAPM. Unsystematic risk is reduced but not completely mitigated with a highly diversified portfolio and the standard CAPM understates the cost of common equity as it does not price all risk exposure. The priced risk in the GCAPM is based on the level of risk actually faced by the investor, not the risk theoretically imposed by the CAPM. Fama and French (2004) find that the CAPM understates returns and risk, based on a large empirical study of portfolios of common stocks with a continuum of low to high betas. The GCAPM also does not assume or require the efficient markets assumption as does the CAPM.

Ahern et al. (2011) find that the CAPM generates lower costs of common equity than the GCAPM. Michelfelder (2015) applied the GCAPM to estimate the cost of common equity to public utilities concluding that the CAPM does not price all risk faced by the investor and that the CAPM understates the cost of common equity for public utilities. The GCAPM is specified as:

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{vol_t[M_{t+1}]}{E_t[M_{t+1}]} vol_t[R_{i,t+1}] corr_t[M_{t+1}, R_{i,t+1}], \tag{1}$$

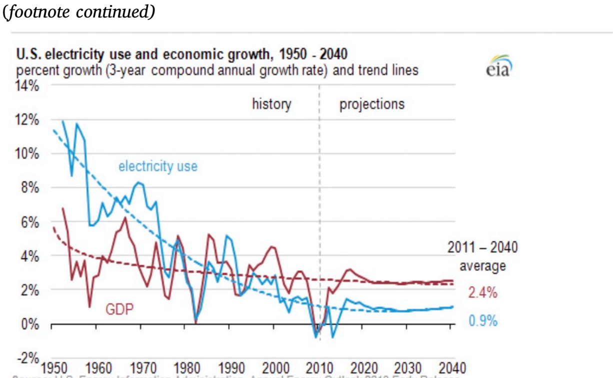
where the anticipated risk premium on an asset i depends on the conditional volatility of the asset; $R_{i,t+1}$ is the ex ante return on asset i; $R_{f,t}$ is the rate of return on a risk-free asset at time t; M_{t+1} is the stochastic discount factor (SDF); vol_t is the conditional volatility of the rate of return; and $corr_t$ is the conditional correlation coefficient. The SDF is the intertemporal marginal rate of substitution in consumption, which is the ratio of expected future marginal utility to the current marginal utility of consumption. This is an important factor to discuss as this model specification allows for the empirical estimation to determine if decoupling results in more stable revenues for utilities relative to changes in the business cycle. If this holds true for a utility during a recession, then investment in the common stock of public utilities could be a business cycle hedge. The SDF is:

$$M_{t+1} = \left(\frac{1}{1+k}\right)\frac{U_{c,t+1}}{U_{c,t}}, \tag{2}$$

where the U_c's are the marginal utilities of consumption and k is the discount rate for the period from t to $t+1$. The ratio M_{t+1} rises if expected future consumption falls below the current level due to the standard concave (to the origin) shape of investors' consumption utility function. This property allows the model to accommodate the business cycle (represented by consumption expenditures) hedging property of a given asset.

If the conditional volatility of intertemporal consumption, or consumption risk, rises, investors will price a greater risk premium into the asset. The sign of the relation between risk premium and its conditional volatility is defined by the correlation ($corr_t$) of the risk premium and the SDF. The sign of the risk premium-to-volatility relation is opposite to the sign of the correlation of the asset return and the ratio of the marginal utilities. A decline in business cycle consumption increases investors' marginal utility. An asset that generates positive returns

(*footnote continued*)



[6] It seems counterintuitive, yet some investors are willing to pay (give up return) for more volatility in an asset's return rather than less, if the pattern of that volatility is desired by those investors. Some researchers confuse risk and volatility as synonymous. For example, gold returns have a tendency to spike upward during recessions and downturns in stock markets. Thus, gold can hedge the downturn in an investor's portfolio and offset the reduction in income from employment. Systematic upward spikes in gold prices increase volatility. Such increases in volatility are generally associated with reductions in the market returns to gold. Such assets with negative relations among returns and volatility are business cycle hedges.

when the business cycle is in a contraction with falling consumption, is a business cycle hedge. Therefore, a negative risk premium-to-volatility slope identifies the asset as a business cycle hedge.

This property allows us to infer whether decoupling causes a public utility common stock to be a business cycle hedge. If profits rise or are flat as GDP declines with lower commodity sales and stable revenues, the common stock price could systematically rise when the business cycle is contracting.[7] A public utility with a strong level of decoupling would conceivably experience stable revenues during a contraction in the business cycle. Therefore, utility profits may rise, or at least not fall, when commodity sales fall generated by consumer end-use efficiency and contracting GDP.

To calibrate the GCAPM, we perform a simple test of this property by estimating the model with the risk premium on gold (percent change in the price of gold per troy ounce minus a risk-free rate). Gold is commonly known to be a business cycle and common stock market hedging asset {Hillier et al. (2006)}. The correlation coefficient between the quarterly percent changes in the price of gold and real GDP (data are publicly available from the St. Louis Federal Reserve Database) from 1968 to 2017 is −0.058. Hillier et al. (2006) show that gold is a common stock market hedge, especially during abnormally high periods of common stock market volatility. We used the daily and monthly US gold commodity cash price data and futures price data to estimate the GCAPM. The risk-premium-to-volatility slope "α" (see footnote 10) is either negative and significant or insignificant using daily and monthly data and many rolling time frames for estimation. These calibration test results for the GCAPM show that the model does detect a hedging asset.[8]

The GCAPM can be applied to any asset that is traded in any financial market and therefore can be applied to all traded public utility common stocks. The GCAPM has the added advantage that the decoupling impact on changes in common stock returns as well as the conditional volatility of these returns can be estimated separately within the same model using the GARCH-in-Mean (GARCH-M) method initially developed for asset model estimation. The GARCH-M method is discussed in the next section.

Decoupling is expected to lower the variance of the operating cash flows of a public utility due to the increased stability of revenues {Moody's (2011)}. The variance of operating cash flows should be driven mainly by the variance of costs as follows: Operating Cash Flows (*OCF*) is Revenues (*R*) – Cost (*C*), therefore the variance of *OCF* is *VAR (R-C) = VAR (R) + VAR (C) + 2COV (R,C)*. Since the volatility of revenues is theoretically equal to zero with decoupling, the covariance of revenues and costs is zero as revenues do not vary, and volatility of *OCF* is purely driven by costs only as *VAR (R-C) = VAR (C)*. Therefore, in comparing the variance of operating cash flows with and without decoupling, the *VAR (OCF with decoupling) = VAR (C) < VAR (OCF without decoupling) = VAR (R) + VAR (C) + 2COV (R,C)* as *VAR (R) = 0* and *COV (R,C) = 0* with decoupling and *VAR (R) > 0* and *COV (R,C) ≠ 0* without decoupling. This is essentially the model used by Moody's (2011) which found that utilities with decoupling experienced a reduction in business risk as measured by the change in the standard deviation of the growth rate in gross profit before and after decoupling.

We also estimate changes in systematic investment risk resulting from decoupling by analyzing the change in the short-term CAPM beta. This short-term beta (12-month), a measure of systematic risk, should be more sensitive to regime changes for a common stock relative to the standard betas estimated with five years of data typically employed to assess investment risk. Beta is expected to decline with decoupling.[9]

The only other studies on the impact of decoupling on the utility cost of capital, Wharton and Vilbert (2015), estimated the impact of decoupling on the cost of capital for the overall electric and gas utility industries. They also addressed the issue that decoupled utilities may represent substantially less than the entire portfolio of assets reflected in the common stock price of a holding company. Using the standard dividend discount model to estimate the cost of common equity portion of their weighted average cost of capital estimates, they regressed this cost of capital on an intensity index of decoupling for each publicly-traded utility common stock with a panel-data regression to estimate the industry impact. They found no statistically significant impact of decoupling on the cost of capital.

The present study estimates the impact on the cost of common equity of the decoupled firm individually rather than that on an industry as a whole. We use the GCAPM and changes in beta before and after the implementation of decoupling to estimate the impact on risk and the cost of common equity.

3. Methodology

The GCAPM is estimated with the GARCH-M method.[10] GARCH-M specifies the conditional risk premium as a linear function of its conditional volatility, which is the specification of the GCAPM in equation (1). Since the returns data contains ARCH effects (available on request), another benefit of using GARCH-M is that it improves the efficiency of the estimates. Engle et al. (1987) developed the GARCH-M method and used it to estimate the relation between US Treasury and corporate bond yield risk premiums and their volatilities.

Two versions of the GCAPM-GARCH-M model are estimated. The first estimation includes a binary variable that reflects the implementation of decoupling for the specific utility ($D_i = 1$ if decoupled, 0 otherwise) in the risk premium equation only and the volatility equation the same:

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma^2_{i,t+1} + \alpha_{i,D}D_{i,t} + \varepsilon_{i,t+1} \tag{3}$$

where "αi, D" is an estimate of the decoupling impact on the risk premium.

The second estimation has the same variable in the volatility equation of the GARCH-M model only and the return equation does not (as shown in footnote 10 in the second set of equations):

$$\sigma^2_{i,t+1} = \beta_0 + \beta_1\sigma^2_{i,t} + \beta_2\varepsilon^2_{i,t} + \beta_{i,D}D_{i,t} + \eta_{i,t+1} \tag{4}$$

[7] One of the most effective "energy efficiency tools" to generate energy use reduction is a recession. Although the energy-use-US-GDP correlation has declined, it remains substantially positive {EIA (2013), as shown in the figure in footnote 4 above, www.eia.gov/todayinenergy/detail.php?id=10491}.

[8] All empirical results on gold are available on request.

[9] Systematic risk is defined as $\beta_i = \rho_{i,m}\ \sigma_i/\sigma_m$, where $\rho_{i,m}$ is the correlation coefficient of the individual stock (i) and the market (m) total rates of return and σ_i and σ_m are the standard deviations of the individual stock and market returns, respectively. Defining variables with superscript "D", to denote decoupling, σ_i^D and $\rho_{i,m}^D$ should be lower as the volatility of the utility's returns are lower with decoupling and the utility's return has a lower correlation with the market return as the utility's revenues and profits are decoupled from the business cycle. Therefore systematic risk is lower with decoupling and defined as $\beta_i^D = \rho_{i,m}^D\ \sigma_i^D/\sigma_m$. Therefore, β_i^D is less than β_i as.

$$\rho^D_{i,m}\sigma_i^D/\sigma^D_m \ < \ \rho_{i,m}\sigma_i/\sigma_m$$

[10] The GCAPM was estimated with the GARCH-M method. The estimated models are.

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma^2_{i,t+1} + \alpha_{i,D}D_{i,t} + \varepsilon_{i,t+1}$$

$$\sigma^2_{i,t+1} = \beta_0 + \beta_1\sigma^2_{i,t} + \beta_2\varepsilon^2_{i,t} + \eta_{i,t+1},$$

And $R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma^2_{i,t+1} + \varepsilon_{i,t+1}$

$$\sigma^2_{i,t+1} = \beta_0 + \beta_1\sigma^2_{i,t} + \beta_2\varepsilon^2_{i,t} + \beta_{i,D}D_{i,t} + \eta_{i,t+1}.$$

where "βi, D "is an estimate of the decoupling impact on the volatility of the risk premium.

These specifications provide separate empirical estimates of the impacts of decoupling on conditional public utility common stock returns and conditional volatility. As event studies, these and all financial market-based event studies face the question of when the event impacted asset prices. Asset prices can reflect forthcoming events before they are implemented. One example that is relevant for this investigation is when decoupling implementation was announced in a utility's regulatory decision. We find that using the date of implementation is a conservative approach to estimating the impact as it is most likely the latest date that a decoupling impact would be detected in a common stock price and much of the impact may already have been priced in the asset. However, if a utility's revenues have been decoupled from sales to the extent that revenues are not affected by the business cycle, then the utility's common stock as a hedging asset would be detected in a zero or negative alpha. Also, if a sufficiently long pre-decoupling time period for observing returns and volatility is obtained, the change in the post-period should be detected as all of the post-decoupling period returns and volatilities are in a different business risk regime.

4. Data

We perform the empirical work on US utilities only. As discussed in the Introduction, decoupling has not been adopted in the EU. EU investor-owned utilities and their regulators have widely adopted price cap regulation, an alternative form of regulation to rate-base-rate-of-return regulation to promote expense and investment efficiency, but not necessarily to encourage utility expenditure on consumer end-use energy and water efficiency. The group of US public utility common stocks includes all electric and gas combination companies that have 95% or more of their revenues decoupled and water utility common stocks that have all of their revenues decoupled before 2014. Data for the common stock rates of return are the total monthly rates of return on the common stock of the public utilities from the Center for Research in Security Prices database (CRSP) of the University of Chicago. Data for each public utility common stock include differing pre- and post-decoupling dates and therefore differing rate of rate and beta samples. The pre-decoupling data for each common stock include all available past monthly returns data in the CRSP before decoupling for that common stock. Post-decoupling rate of returns data for all common stocks end at December 2014 for consistency in the post-decoupling ending period for all utility common stocks. We calculated historical monthly common stock equity risk premiums monthly common stock returns less the monthly yields on long-term U.S. Treasury Bonds for the selected publicly traded water utilities using common stock returns data from the CRSP database and Morningstar (2015) SBBI® 2015 Market Results for Stocks, Bonds, Bill and Inflation 1926–2015 and the Federal Reserve Statistical Release H.15 for long-term Treasury bond yields. The CAPM beta data include all short-term betas available for each public utility common stock that has been decoupled in the CRSP database and ends at 2014. They are available on an annual basis. The CAPM short-term beta[11] is a one-year estimate of beta that approximately involves regressing daily rates of return on the public utility common stock on a market index as shown footnote 10. The standard beta available from financial firm databases such as Value Line Investment Survey or CRSP is a 5-year beta based on regressing monthly or weekly common stock rates of return for the past 5 years on a market index. We find that the longer-term beta would be less sensitive to regime changes in risk such as decoupling. We restrict the sample of pre- and post-decoupling betas for each common stock so that the number of beta observations are the same before and after decoupling.

Since the number of data observations has different times series of ranges for each public utility common stock and decoupling occurred on different dates for most utilities, we have developed Table 1 to show each public utility common stock's data date range, that is, the dates and number of risk premium (rate of return minus risk-free rate) observations used to estimate the GCAPM and the total number of betas used for the pre- and post beta comparison. Table 1 also has the date of decoupling for each public utility.

5. Results and discussion

Table 2 presents the public utility common stocks in the study and the empirical results of the GCAPM estimates. The risk-premium-to-volatility slopes ("alpha") are shown along with the decoupling slope in the risk-premium and volatility equations for each electric, electric and gas combination, and water utility common stocks. The decoupling slope in the risk-premium equation will be negative (positive) if the risk premium should decline (rise) and decoupling creates a reduction (increase) in business risk. None of these slope estimates are statistically significant. The decoupling slope in the volatility equation should be negative (positive) if decoupling caused a reduction (increase) in the volatility of the profit of the utilities. Two of the slopes are negative and significant at $p = 0.10$, yet the magnitudes of the slopes are very small.

All of the alphas, except for one of the energy utilities are positive and significant, yet none in the water utility group are significant. These results indicate that the energy utility common stocks are not business cycle hedging assets and that their profits are synchronized with the business cycle. The results for the water group may indicate that they are business cycle hedging assets as none are statistically significant. The zero value for alpha implies that there is no relation between the business cycle as represented by expected changes in consumption and the return on water utility common stocks. Water utility profits are not correlated with the business cycle even in the absence of decoupling. Also, water use attrition is occurring across the US as households (water consumption per household is declining) due to the use of water-efficient appliances (such as low-flow faucets, showerheads and efficient toilets) and the change per capita water use habits to conserve water.

Table 3 presents the pre- and post-decoupling changes in the systematic risk as represented by the short-term CAPM beta for all of the public utility common stocks. The betas drop after the implementation of decoupling but none of the changes in beta are statistically significant using a t-statistic at a $p = 0.05$. Additionally, the standard errors of the betas (σ_{pre} and σ_{post}) show no consistent pattern of increasing or decreasing after decoupling.

Our results do not show any statistically significant impacts of decoupling on the cost of common equity and risk. Therefore, we find no evidence to conclude that decoupling affects investor perceived risk or the cost of common equity. While electric and gas public utility common stocks were not found to be business cycle hedges, we do find that water utility common stocks may be business cycle hedges.

Our results are based on the moderate amount of data available to date. Although we would obviously prefer more data than are available at this juncture, there is no time to wait for a larger volume of data. Regulators and utilities have been and are implementing policy now as if decoupling does reduce risk and the costs of capital without any

[11] The CRSP short-term beta is described by CRSP as "a statistical measurement of the relationship between two time series, and has been used to compare security data with benchmark data to measure risk in financial data analysis. CRSP provides annual betas computed using the methods developed by Scholes and Williams (Myron Scholes and Joseph Williams, "Estimating Betas from Nonsynchronous Data," *Journal of Financial Economics*, vol 5, 1977, 309–327). Beta is calculated each year as follows where.

$$\beta_i = \frac{\Sigma(lr_{i,t} * M3_t) - \left(\frac{1}{n_i}\right) * (\Sigma lr_{i,t}) * (\Sigma M3_t)}{\Sigma(lM_t * M3_t) - \left(\frac{1}{n_i}\right) * (\Sigma lM_t) * (\Sigma M3_t)}$$

Table 1
Data description for risk premiums and betas.

Electric, Elec. & Gas Comb. Utility	Effective Decoupling Date	Beginning of Measurement Period Returns Data	Total # of Months Return Data	Total Number of Pre- and Post- Annual Beta Observations
Consolidated Edison	10/2007	07/30/02	126	10
Pacific Gas & Electric	01/1983	01/31/53	720	60
Edison International	01/1983	01/31/53	720	60
CH Energy Group	07/2009	01/31/06	84	6
CMS Energy Corp.	05/2010	9/30/07	64	6
Hawaii Electric	12/2010	11/30/08	50	5
Portland General Electric	12/2010	11/30/08	50	6
Idaho Power	03/2007	05/30/01	140	12
Water Utility				
American States Water	1/2002	6/2002	153	12
California Water	1/2009	10/2001	162	12
Connecticut Water	7/2008	10/2002	150	10
Artesian Resources	11/2008	6/1996	226	12

Table 2
GCAPM estimation results.[a]

Electric, Elec. & Gas Comb. Utility	α_i	α_D	β_D
Consolidated Edison	1.460***	0.004	−0.000
Pacific Gas & Electric	1.781***	0.001	−0.001
Edison International	1.379***	0.003	0.000
CH Energy Group	2.094***	0.004	−0.000
CMS Energy Corp.	1.440***	0.011	−0.000
Hawaii Electric	1.607***	0.004	−0.000*
Portland General Electric	0.461	0.010	−0.000
Idaho Power	1.939***	0.003	−0.000
Water Utility	$\boldsymbol{\alpha_i}$	α_D	β_D
American States Water	0.596	0.011	0.000
California Water	0.525	0.004	−0.000
Connecticut Water	−1.008	0.009	0.000
Artesian Resources	3.006	−0.004	−0.002*

[a] The GCAPM was estimated with the GARCH-M method. The estimated models are.

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma_{i,t+1}^2 + \alpha_{i,D}D_{i,t} + \varepsilon_{i,t+1}$$

$$\sigma_{i,t+1}^2 = \beta_0 + \beta_1\sigma_{i,t}^2 + \beta_2\varepsilon_{i,t}^2 + \eta_{i,t+1},$$

And $R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma_{i,t+1}^2 + \varepsilon_{i,t+1}$

$$\sigma_{i,t+1}^2 = \beta_0 + \beta_1\sigma_{i,t}^2 + \beta_2\varepsilon_{i,t}^2 + \beta_{i,D}D_{i,t} + \eta_{i,t+1}.$$

Table 3
Changes in systematic risk from decoupling. [a]

	Mean β_{PRE}	Mean β_{POST}	σ (β_{PRE})	σ(β_{POST})	t-Statistic
Electric, Elec. & Gas Comb. Utility					
Consolidated Edison	0.608	0.427	0.172	0.064	−1.329
Pacific Gas & Electric	0.522	0.535	0.174	0.373	0.112
Edison International	0.588	0.582	0.199	0.294	−0.051
CH Energy Group	0.680	0.401	0.279	0.326	−0.759
CMS Energy Corp.	0.758	0.559	0.198	0.140	−0.815
Hawaii Electric	0.619	0.570	0.253	0.155	−0.171
Portland General Electric	0.637	0.658	0.069	0.052	−0.151
Idaho Power	0.905	0.728	0.251	0.125	−0.818
Mean	0.670	0.560			
Water Utility					
American States Water	0.975	0.623	0.535	0.279	−1.430
California Water	1.192	0.520	0.544	0.257	−2.735***
Connecticut Water	0.664	0.502	0.235	0.176	−1.232
Artesian Resources	0.075	0.146	0.100	0.161	0.909
Mean	0.434	0.475			

[a] Beta is the annual year-ending beta from the CRSP database. The data timeframe is different for each utility with an equal number of annual pre- and post-decoupling beta data observations for the specific stock in the CSRP database and ends in 2014. Each single beta was estimated with one year of daily rate of return data. See Table 1 and footnote 11. ***, **, * refers to statistical significance at 0.01, 0.05, and 0.10 respectively.

evidence that it does. This paper serves as an early warning signal, albeit with the limited evidence that is available.

6. Conclusion and policy implications

We conclude that decoupling has no statistically measurable impact on the cost of common equity based on our empirical analysis for electric, electric and gas, and water utility common stocks. Some researchers may view this result as a "non-result." This is an important finding as it is consistent with the empirical findings of Vilbert et al. (2016). It is also important for policy globally as decoupling is considered as a potential reducer to risk and the cost of common equity by regulators and public utilities in the US based on intuition, without any empirical evidence.

Moody's (2011) finds a reduction in business risk as measured by the change in the variability of gross profit after decoupling but did not estimate the impact on the cost of common equity. Moody's (2011) did find that electric utilities were somewhat reluctant to adopt decoupling as electric utility executives anticipated that growth in sales would return to the industry after the steep recession that ended with the business cycle trough in June 2009 {NBER (2018)}. Since the US business cycle expansion post-June 2009, electricity sales have remained almost flat, which may have caused the change in sentiment toward decoupling by electric utility executives. Growth in a utility's commodity sales above the level used to design regulated rates would increase the profit and rate of return on common equity. The US investor-owned electric utility industry also expected that the adoption of decoupling would cause state public utility regulators to reduce their allowed rate of return under the notion that it reduces risk. Moody's (2011) was written soon after the recession had ended, but the anticipated growth in sales has not materialized after more than ten years into the US business cycle expansion. A few years after the Moody's (2011) study, the EEI found in a more recent report a change in sentiment {EEI (2015)} that electric utilities favor decoupling and that it has become more widespread across the US.

We conclude that decoupling has no statistically significant impact on investor perceived risk and the cost of common equity. This does not mean necessarily that decoupling has no impact on the perceived risk and the cost of common equity of public utilities. We find that it cannot be isolated and estimated, given the many other factors affecting investor perceived risk. For many electric utilities, some current major risk drivers are flat or declining sales from customer-owned solar projects and energy efficiency resources; the requirement to buy back excess customer generated electric from renewable resources at full retail rates (net metering); increasing requirements in the proportion of a utility's sales that have to be generated from renewable energy, causing larger purchases of renewable energy credits (known as renewable portfolio standards that have been adopted by many states and across Europe); increasingly stringent environmental regulations on coal plants; and the impact of falling and low natural gas prices on the competitiveness of existing coal and nuclear plants.

For water utilities, we find their common stocks to be moderate business cycle hedges (no correlation with the business cycle rather than a strong negatively correlated hedge). Since water utility sales are declining on a per capita basis and unassociated with the business cycle, decoupling may provide financial protection if water revenues decline. To the extent that there is positive growth in the number of water utility customers that offsets the declining per capita consumption, total revenues and sales may not be falling. The impact of decoupling on water utility investment risk and cost of common equity was not able to be detected in this study. This is the first study on decoupling in the water utility industry and an area for future research.

Another explanation for the lack of detection of a change in risk or the cost of common equity from decoupling is that risk may be created with the implementation of decoupling and the net impact may not be clear as an increase or decrease in risk as Vilbert et. al. (2016) and Wharton and Vilbert (2015) concludes. They find that the implementation of decoupling is a new and alternative regulatory regime that may be a new source of regulatory risk for the utility. Finally, as discussed in detail in the Introduction above, volume risk, that is, the fundamental nature of the business and business risk, is not alleviated by changing the reward mechanism, and attempts to do so may increase risk and the cost of common equity. The point is that there are cogent theoretical and practical bases to expect that decoupling increases or decreases risk, so it is problematic to develop an *a priori* hypothesis to test a one-way directional impact of risk and return from decoupling.

Therefore, we do not recommend that public utility regulators in the US or elsewhere reduce or increase authorized common equity cost rates in the presence of decoupling mechanisms based on the assumption of changed or reduced risk. The impact is *de minimis* and not statistically significant amongst all of the other investor perceived risk factors affecting the market prices of public utility common stocks. While an alternative research approach may attempt to isolate the impacts of other individual risk factors on the cost of common equity and risk, making for a long regression equation, we cannot detect a statistically significant signal of decoupling on the cost of common equity or volatility. As a contrast, for example, the risk and cost of common equity impact of owning nuclear power generation assets (versus no nuclear assets) has a measureable impact on investors' returns, risk and cost of common equity without attempting to isolate the myriad of other risk variable impacts. Decoupling as a regulatory policy mechanism to encourage public utilities to provide resources and funding to their consumers to conserve electricity, natural gas, and water (therefore also wastewater flows) has no *measurable* impact on the investment risk and the cost of common equity (either up or down). As a policy prescription, public utility regulators should not adjust the allowed rate of return which affects the public utility's rates as a spillover impact of using decoupling to promote environmental policy.

Finally, the US may be further ahead in adopting rate mechanisms that address energy and water efficiency due to its long-term lag relative to Europe in the efficient use of energy and water and the recent "necessity-is-the-mother-of-invention" US driver of energy and water efficiency. European and regulators globally should proceed slowly in adopting decoupling and assuming that decoupling reduces risk as there is no empirical evidence to date that it does.

An extension of this research could evaluate risk premiums or discounts in bond yields as there are many more investor-owned utilities which have outstanding bonds relative to those that have their own publicly traded common stock due to consolidation in the utility industry in the US. For example, Exelon is the holding company of six utilities whose stocks were publicly traded on the New York Stock Exchange. They are Atlantic City Electric, Baltimore Gas and Electric, Commonwealth Edison, Delmarva Power and Light, Philadelphia Electric and Potomac Edison Power. Another future extension could focus on decoupling when some EU investor-owned utilities and regulators, inevitably, adopt decoupling should it prove to substantially encourage more conservation in the US. An investigation of hedging costs and savings, risk impacts, and effects on profits with and without decoupling may shed more light on the topic. There also needs more research on water/wastewater decoupling as this is the first study known to date on the topic involving cost of capital and risk. Lastly, a social welfare comparison, separating out consumer-surplus and shareholder-value creation and investigating the impacts on conservation from price and revenue caps is another extension of this paper for future research.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2019.04.006.where R_i is the conditional total return on the stock, R_f is the risk-free rate of return, $\sigma^2_{i,\ t+1}$ is the next period conditional volatility, D is the dummy variable that equals 1 when decoupling is in place, and α_D and β_D are the slopes on the conditional returns and volatility decoupling dummy variable that represent the impact of decoupling on those variables. Monthly returns data are from the CRSP database and includes all data available from the CRSP database and ends at 12/2014. The monthly risk-free rate of return is the Ibbotson income return on Long-Term US Treasuries. ***, **, * refers to statistical significance at p values of 0.01, 0.05 and 0.10 respectively.where R_i is the conditional total return on the stock, R_f is the risk-free rate of return, $\sigma_{2i,\ t+1}$ is the next period conditional volatility of the risk premium for asset *i.* $\varepsilon_{i,t}$ and $\eta_{i,t+1}$ are the error terms for the mean and volatility equations, D is the dummy variable that equals 1 when decoupling is in place for utility i, and α_D and β_D are the slopes on the conditional returns and volatility decoupling dummy variable that represent the impact of decoupling on those variables.

The parameter, α_i, is the risk-premium-to-volatility slope. It is specified from equation (1) as:

$$\alpha_{i,t} = -\frac{vol_t\,[M_{t+1}]}{E_t\,[M_{t+1}]} corr_t\,[M_{t+1},\ R_{i,t+1}]$$

It is positive for assets that are not business cycle hedges as $corr_t$ is negative. A rising (falling) M and rising (falling) expected marginal utility from falling (rising) consumption in a recession is associated with a fall (rise) in returns. The above empirical model specifies a 0 intercept in the risk premium equation as does the GCAPM. The estimation results support the 0 intercept specification (results available upon request).

β_i is the Beta for security i for the year being calculated, $r_{i,t}$ is the return of security i at day t,$lr_{i,t} = \ln(1+r_{i,t})$ is the natural log of the return of security i at time $t+1$ or the continuously compounded return, M_t is the value-weighted market return at time t, $lM_t = \ln(1+M_t)$ is the natural log of the value-weighted market return at time $t+1$ or the continuously compounded return.

$M3_t = lM_t\text{-}1 + lM_t + lM_{t+1}$ is the three-day moving window of the above market return, n_i is the number of non-missing returns for security i during the year, where the summations are over t and include all days on which security i traded, beginning with the first trading day of the year and ending with the last trading day of the year."

(http://www.crsp.com/products/documentation/index-definitions-calculations, accessed March 12, 2019.)

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