S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief. _______________________________________	))))))	Case No. U-20134

EXHIBITS

OF

JAMES R. ANDERSON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Schedule B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Electric High Voltage Distribution (HVD)
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-12 (JRA-1)
Schedule: B-5.4
Page: 2 of 3
Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
			Projected Bridge Year			**Projected Test Year**
Line No.	**Description**	**Historical 12 Mos Ended 12/31/2017**	**12 Mos Ended 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	HVD New Business Program	7,113	13,572	10,000	23,572	10,000
	Contractor	2,317	4,126	3,243	7,369	3,243
	Labor	667	1,187	933	2,120	933
	Materials	3,561	6,339	4,984	11,323	4,984
	Business Expenses	6	11	8	19	8
	Contingency	-	909	45	954	45
	Other (Loadings, Chargebacks)	562	1,001	787	1,787	787
2	Reliability Program	51,926	84,686	107,243	191,929	107,243
	Contractor	18,210	29,585	37,609	67,194	37,609
	Labor	3,112	5,056	6,427	11,483	6,427
	Materials	12,509	20,323	25,836	46,159	25,836
	Business Expenses	16	26	33	59	33
	Contingency	-	324	-	324	-
	Other (Loadings, Chargebacks)	18,079	29,372	37,338	66,710	37,338
3	Capacity Program	30,519	29,645	35,336	64,981	35,336
	Contractor	9,588	9,047	11,101	20,149	11,101
	Labor	2,438	2,300	2,823	5,123	2,823
	Materials	7,322	6,909	8,478	15,387	8,478
	Business Expenses	64	60	74	134	74
	Contingency	-	847	-	847	-
	Other (Loadings, Chargebacks)	11,107	10,481	12,861	23,342	12,861
4	Demand Failures Program	33,074	29,467	30,672	60,139	30,672
	Contractor	7,911	6,953	7,337	14,290	7,337
	Labor	2,775	2,439	2,574	5,013	2,574
	Materials	10,453	9,187	9,694	18,881	9,694
	Business Expenses	9	8	8	16	8
	Contingency	-	398	-	398	-
	Other (Loadings, Chargebacks)	11,925	10,481	11,059	21,539	11,059
5	Asset Relocation Program	168	601	848	1,449	848
	Contractor	274	983	1,388	2,371	1,388
	Labor	27	98	138	237	138
	Materials	123	440	621	1,061	621
	Business Expenses	0	0	0	0	0
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	(257)	(921)	(1,299)	(2,220)	(1,299)
6	Electric Operations Other Program	1,055	5,030	5,638	10,668	5,638
	Contractor	141	672	754	1,426	754
	Labor	1	7	8	15	8
	Materials	867	4,134	4,633	8,767	4,633
	Business Expenses	2	8	8	16	8
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	44	209	234	443	234
					-	-
					-	-
					-	-
7	**Total Capital**	123,854	163,001	189,737	352,738	189,737

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Electric HVD 5-Year Historical
Summary of Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-17 (JRA-2)
Page: 1 of 1
Witness: JRAnderson
Date: May 2018

Line No.	(a) Program / Sub-Program	(b) Witness	(c) 2013 Actuals	(d) 2014 Actuals	(e) 2015 Actuals	(f) 2016 Actuals	(g) 2017 Actuals	(h) 5-Year Average	(i) 2018 Projected Bridge Year	(j) 2019 Projected Test Year	(k) Test Year vs 5-Year Average Variance (j - h)
1	HVD New Business	JRAnderson	5,496	8,213	7,035	27,864	7,113	11,144	13,572	10,000	-1,144
2	**HVD New Business**		**5,496**	**8,213**	**7,035**	**27,864**	**7,113**	**11,144**	**13,572**	**10,000**	**-1,144**
3	HVD Lines Reliability	JRAnderson	17,703	26,702	14,640	37,825	17,325	22,839	36,672	38,837	15,998
4	LVD Substations Reliability	JRAnderson	13,898	6,780	8,936	11,135	14,112	10,972	19,273	20,202	9,230
5	HVD Subs Reliability	JRAnderson	5,672	2,021	3,458	3,850	4,342	3,869	3,765	4,879	1,010
6	HVD System Protection	JRAnderson	1,334	2,372	1,899	1,569	4,244	2,284	1,976	2,325	41
7	Substations Comm Upgrades	JRAnderson	0	10	508	1,324	11,903	2,749	23,000	41,000	38,251
8	**Reliability**		**38,607**	**37,885**	**29,441**	**55,703**	**51,926**	**42,712**	**84,686**	**107,243**	**64,531**
9	HVD Lines & Subs Capacity	JRAnderson	9,308	13,596	15,612	20,965	16,823	15,261	17,814	22,188	6,927
10	LVD Substations Capacity	JRAnderson	9,768	10,927	7,209	18,044	13,696	11,929	11,831	13,148	1,219
11	**Capacity**		**19,076**	**24,523**	**22,821**	**39,009**	**30,519**	**27,190**	**29,645**	**35,336**	**8,146**
12	HVD Lines and Substations Failures	JRAnderson	12,132	11,688	14,877	13,206	17,623	13,905	15,889	16,849	2,944
13	LVD Substations Failures	JRAnderson	8,369	11,125	7,613	9,399	15,451	10,391	13,578	13,823	3,432
14	**Demand Failures**		**20,501**	**22,813**	**22,490**	**22,605**	**33,074**	**24,297**	**29,467**	**30,672**	**6,375**
15	HVD Asset Relocations	JRAnderson	-61	364	1,056	288	168	363	601	848	485
16	**Asset Relocations**		**-61**	**364**	**1,056**	**288**	**168**	**363**	**601**	**848**	**485**
17	Computer & Equipment	JRAnderson	282	393	113	76	430	258.8	260	270	11
18	System Control Projects	JRAnderson	280	174	88	2	619	232.6	1700	2050	1,817
19	NERC/NESC Compliance	JRAnderson	0	0	0	0	0	0	2920	3160	3,160
20	Substation Fall Protection	JRAnderson	523	251	196	80	6	211.2	150	158	-53
21	**Electric Operations Other**		**1,085**	**818**	**397**	**158**	**1,055**	**703**	**5,030**	**5,638**	**4,935**
22	**Total Capital - Loaded**		**84,704**	**94,616**	**83,240**	**145,627**	**123,855**	**106,408**	**163,001**	**189,737**	**83,329**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
HVD New Business Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-18 (JRA-3)
Page: 1 of 1
Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	HVD New Business Program	7,113	13,572	10,000	23,572	10,000
	Contractor	2,317	4,126	3,243	7,369	3,243
	Labor	667	1,187	933	2,120	933
	Materials	3,561	6,339	4,984	11,323	4,984
	Business Expenses	6	11	8	19	8
	Contingency		909	45	954	45
	Other (Loadings, Chargebacks)	562	1,001	787	1,787	787
					-	-
					-	-
					-	-
2	**Total Capital**	7,113	13,572	10,000	23,572	10,000

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
HVD Reliability Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-19 (JRA-4)
Page: 1 of 1
Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	HVD Lines Reliability	17,325	36,672	38,837	75,509	38,837
	Contractor	9,830	20,808	22,036	42,844	22,036
	Labor	337	713	755	1,467	755
	Materials	1,592	3,370	3,569	6,939	3,569
	Business Expenses	4	8	9	17	9
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	5,562	11,773	12,468	24,241	12,468
2	LVD Substations Reliability	14,112	19,273	20,202	39,475	20,202
	Contractor	1,697	2,282	2,429	4,711	2,429
	Labor	1,259	1,693	1,802	3,495	1,802
	Materials	6,037	8,121	8,642	16,763	8,642
	Business Expenses	6	8	8	16	8
	Contingency		290	-	290	-
	Other (Loadings, Chargebacks)	5,114	6,879	7,321	14,199	7,321
3	HVD Substations Reliability	4,342	3,765	4,879	8,644	4,879
	Contractor	554	476	622	1,098	622
	Labor	724	622	813	1,435	813
	Materials	1,291	1,109	1,451	2,560	1,451
	Business Expenses	1	1	1	2	1
	Contingency		34	-	34	-
	Other (Loadings, Chargebacks)	1,772	1,523	1,992	3,515	1,992
4	HVD System Protection	4,244	1,976	2,325	4,301	2,325
	Contractor	1,329	619	728	1,347	728
	Labor	456	212	250	462	250
	Materials	930	433	509	942	509
	Business Expenses	1	0	0	1	0
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	1,528	711	837	1,549	837
5	Substations Comm Upgrades	11,903	23,000	41,000	64,000	41,000
	Contractor	4	9	15	24	15
	Labor	4,800	9,275	16,534	25,809	16,534
	Materials	337	651	1,160	1,811	1,160
	Business Expenses	2,659	5,138	9,159	14,297	9,159
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	4,102	7,927	14,131	22,058	14,131
6	**Total Capital**	51,926	84,686	107,243	191,929	107,243

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
HVD Capacity Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-20 (JRA-5)
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Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				**Projected Test Year**
		Historical	**Projected Bridge Year**			
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ended 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	HVD Lines & Subs Capacity	16,823	17,814	22,188	40,002	22,188
	Contractor	6,469	6,728	8,532	15,260	8,532
	Labor	1,746	1,815	2,302	4,117	2,302
	Materials	2,212	2,300	2,917	5,218	2,917
	Business Expenses	33	34	43	78	43
	Contingency		318	-	318	-
	Other (Loadings, Chargebacks)	6,364	6,618	8,393	15,012	8,393
2	LVD Substations Capacity	13,696	11,831	13,148	24,979	13,148
	Contractor	3,119	2,574	2,994	5,568	2,994
	Labor	692	571	665	1,236	665
	Materials	5,110	4,217	4,906	9,123	4,906
	Business Expenses	31	25	30	55	30
	Contingency		529	-	529	-
	Other (Loadings, Chargebacks)	4,743	3,914	4,554	8,468	4,554
					-	-
					-	-
					-	-
3	**Total Capital**	30,519	29,645	35,336	64,981	35,336

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
HVD Demand Failures Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-21 (JRA-6)
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Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ended 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	HVD Lines and Substations Failures	17,623	15,889	16,849	32,738	16,849
	Contractor	6,489	5,805	6,204	12,009	6,204
	Labor	1,340	1,199	1,281	2,480	1,281
	Materials	3,445	3,082	3,294	6,376	3,294
	Business Expenses	2	2	2	4	2
	Contingency		123	-	123	-
	Other (Loadings, Chargebacks)	6,346	5,678	6,068	11,745	6,068
2	LVD Substations Failures	15,451	13,578	13,823	27,401	13,823
	Contractor	1,423	1,225	1,273	2,498	1,273
	Labor	1,435	1,236	1,284	2,519	1,284
	Materials	7,008	6,034	6,269	12,303	6,269
	Business Expenses	7	6	6	12	6
	Contingency		275	-	275	-
	Other (Loadings, Chargebacks)	5,578	4,803	4,991	9,794	4,991
					-	-
					-	-
					-	-
3	**Total Capital**	33,073	29,467	30,672	60,139	30,672

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
HVD Asset Relocation Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-22 (JRA-7)
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Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				**Projected Test Year**
		Historical	**Projected Bridge Year**			
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ended 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	HVD Asset Relocations	168	601	848	1,449	848
	Contractor	274	983	1,388	2,371	1,388
	Labor	27	98	138	237	138
	Materials	123	440	621	1,061	621
	Business Expenses	0	0	0	0	0
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	(257)	(921)	(1,299)	(2,220)	(1,299)
					-	-
					-	-
					-	-
2	**Total Capital**	168	601	848	1,449	848

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
HVD Electric Operations Other Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-23 (JRA-8)
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Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ended 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	Computer & Equipment	430	260	270	530	270
	Contractor	1	1	1	1	1
	Labor	1	0	0	1	0
	Materials	424	256	266	522	266
	Business Expenses	1	1	1	2	1
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	1	1	1	1	1
2	System Control Projects	619	1,700	2,050	3,750	2,050
	Contractor	140	383	462	845	462
	Labor	0	1	2	3	2
	Materials	438	1,203	1,451	2,654	1,451
	Business Expenses	0	1	1	2	1
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	41	111	134	245	134
3	NERC/NESC Compliance	-	2,920	3,160	6,080	3,160
	Contractor	-	1,123	1,215	2,338	1,215
	Labor	-	303	328	631	328
	Materials	-	384	415	799	415
	Business Expenses	-	6	6	12	6
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	1,105	1,195	2,300	1,195
4	Substation Fall Protection	6	150	158	308	158
	Contractor		-	-	-	-
	Labor	0	11	12	23	12
	Materials	3	84	89	173	89
	Business Expenses		-	-	-	-
	Contingency		-	-	-	-
	Other (Loadings, Chargebacks)	2	55	58	113	58
					-	-
					-	-
					-	-
5	**Total Capital**	1,055	5,030	5,638	10,668	5,638

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
High Voltage Distribution (HVD) Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending December 31, 2019
($000)

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2019 Test Year	(d) Units	(e) Unit Type	(f) Investment Category
1	HVD New Business	Completion of new 8.5 mile 138 kV line to connect a new customer-owned substation in mid-Michigan (began in 2018)	375			
2		Completion of new 138 kV dedicated customer substation and 0.2 miles of 138 kV line in southern Michigan (began in 2018)	165			
3		New 138 kV dedicated customer substation and 0.6 miles of 138 kV line in west Michigan	3,000			
4		Anticipated projects yet to be specifically identified	6,460			
5		**HVD Strategic Customers Total**	**10,000**			
6	HVD Lines Reliability	Rosebush - New Line	2,265	6	Miles	Rebuild
7		Ionia #2	2,032	6.5	Miles	Rebuild
8		Fine Lake South	1,893	5	Miles	Rebuild
9		Gun Lake (Martin Spur)	1,812	5.4	Miles	Rebuild
10		Mendon - Wakeshma Spur	1,725	5.3	Miles	Rebuild
11		North Adams - West (025I)	1,719	6.2	Miles	Rebuild
12		West Branch West (066I)	1,611	5	Miles	Rebuild
13		Pierson (Trufant to Greenville - East)	1,260	4.2	Miles	Rebuild
14		Pierson (Trufant to Greenville - West)	1,241	3.8	Miles	Rebuild
15		Fine Lake North (023B)	1,205	4	Miles	Rebuild
16		Hammond Rd	965	2	Miles	Rebuild
17		Orleans	949	2	Miles	Rebuild
18		Joppa	835	2.3	Miles	Rebuild
19		Union City - North rebuild	810	2	Miles	Rebuild
20		Greenville	578	1.1	Miles	Rebuild
21		Union City - North Relocate	531	1.7	Miles	Rebuild
22		Fine Lake Towers	332	0.8	Miles	Rebuild
23		St. Charles	1,234	23.1	Miles	Rehabilitation
24		Lake City PH1	704	8.3	Miles	Rehabilitation
25		Grover	678	8	Miles	Rehabilitation
26		Hamilton PH1	653	7.7	Miles	Rehabilitation
27		Lake City PH2	611	7.2	Miles	Rehabilitation
28		Hamilton PH2	602	7.1	Miles	Rehabilitation
29		Glen Oaks	594	7	Miles	Rehabilitation
30		Eastwood	432	5.1	Miles	Rehabilitation
31		Fennville	136	1.6	Miles	Rehabilitation
32		Projects to be identified	1,350	~16	Miles	Rehabilitation
33		Pole Replacements	10,081	560	Poles	
34		**HVD Lines Reliability Total**	**38,837**			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
High Voltage Distribution (HVD) Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending December 31, 2019
($000)

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2019 Test Year	(d) Units	(e) Unit Type	(f) Investment Category
1	LVD Substations Reliability					
2		Carson City	675			Rebuild Substation
3		Port Calcite	615			Rebuild Substation
4		Walloon	1,500			Rebuild Substation
5		Five Channels Hydro	900			New Substation
6		Bentheim	1,500			Rebuild Substation
7		Additional substation rebuild to be identified	810			Rebuild Substation
8		Mobile #23	3,000			New Mobile Substation
9		Alger	90			Animal Mitigation
10		Ballenger	90			Animal Mitigation
11		Becker	90			Animal Mitigation
12		Chapin	90			Animal Mitigation
13		Dean Road	113			Animal Mitigation
14		Duquite	90			Animal Mitigation
15		East Genesee Avenue	90			Animal Mitigation
16		Honor	90			Animal Mitigation
17		Kent City	90			Animal Mitigation
18		Kipp Road	113			Animal Mitigation
19		Larkin	113			Animal Mitigation
20		Neeley	90			Animal Mitigation
21		Norton	90			Animal Mitigation
22		Plainfield	90			Animal Mitigation
23		Rix Road	90			Animal Mitigation
24		Rodney	90			Animal Mitigation
25		Skylark	113			Animal Mitigation
26		Smallwood	90			Animal Mitigation
27		Standish	90			Animal Mitigation
28		Vanderbilt	113			Animal Mitigation
29		Village Green	113			Animal Mitigation
30		19 Substations to be determined	1,975			Animal Mitigation
31		5 Transformer Replacements - Harlem, Leland, Mendon, Northport, and Schuss Mountain Substations	3,000			Transformer Replacement
32		90 Regulator Replacements - locations to be determined	3,000			Regulator Replacement
33		Reclosers, 138kV fuses, and spring operated ground switches (SOGS) - locations to be determined	1,202			Other Replacement
34		**LVD Substations Reliability Total**	**20,202**			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
High Voltage Distribution (HVD) Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending December 31, 2019
($000)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected 2019 Test Year**	**Units**	**Unit Type**	**Investment Category**
1	HVD Substations Reliability					
2		Bronson 288	120	1	Breakers	Circuit Breaker and Circuit Switcher
3		Cement City 266 & 388	240	2	Breakers	Circuit Breaker and Circuit Switcher
4		Emmet 146, 1177, & 1288	500	3	Breakers	Circuit Breaker and Circuit Switcher
5		Kellogg 188 & 277	240	2	Breakers	Circuit Breaker and Circuit Switcher
6		North Belding 200, 1488, & 1588	360	3	Breakers	Circuit Breaker and Circuit Switcher
7		Ventura 400	150	1	Breakers	Circuit Breaker and Circuit Switcher
8		Vernon 166	120	1	Breakers	Circuit Breaker and Circuit Switcher
9		Wealthy 499, 766 & 1077	420	3	Breakers	Circuit Breaker and Circuit Switcher
10		Wexford 1177	120	1	Breakers	Circuit Breaker and Circuit Switcher
11		White Lake 166, 199, 388, 488, & 600	660	5	Breakers	Circuit Breaker and Circuit Switcher
12		Whitestone Point 177 & 277	240	2	Breakers	Circuit Breaker and Circuit Switcher
13		Chauncey TB1	80			Transformer Bushing Replacement
14		Eleventh Street TB1	80			Transformer Bushing Replacement
15		Ervin TB1	80			Transformer Bushing Replacement
16		Kiesel TB1	80			Transformer Bushing Replacement
17		Lambertville TB1	80			Transformer Bushing Replacement
18		LaSalle TB1	80			Transformer Bushing Replacement
19		Morrell TB1	80			Transformer Bushing Replacement
20		Orbital TB1	80			Transformer Bushing Replacement
21		Oshtemo TB1	80			Transformer Bushing Replacement
22		Otisville TB1	80			Transformer Bushing Replacement
23		Palmer TB1	80			Transformer Bushing Replacement
24		Scottville TB1	80			Transformer Bushing Replacement
25		Treatment TB1 & TB2	100			Transformer Bushing Replacement
26		Twin Lake TB1	80			Transformer Bushing Replacement
27		Watkins TB1	80			Transformer Bushing Replacement
28		Whitestone Point TB1-2	50			Transformer Bushing Replacement
29		Lambertville 199	35	1	Switches	Switch Replacements
30		Owosso 299 & 399	100	2	Switches	Switch Replacements
31		Swartz Creek 199	30	1	Switches	Switch Replacements
32		Tecumseh Products 188	35	1	Switches	Switch Replacements
33		Whitestone Point 175, 275, & 199	100	3	Switches	Switch Replacements
34		Hazelwood	15	1	Potential Transformers	Potential Transformer Replacements
35		Hughes Road	15	1	Potential Transformers	Potential Transformer Replacements
36		Simpson	15	1	Potential Transformers	Potential Transformer Replacements
37		Ventura	45	3	Potential Transformers	Potential Transformer Replacements
38		Wexford	15	1	Potential Transformers	Potential Transformer Replacements
39		White Lake	34	2	Potential Transformers	Potential Transformer Replacements
40		**HVD Substations Reliability Total**	**4,879**			
41	HVD System Protection		-			
42		Amber	150	2	Relay Packages	Relay Replacements
43		Bangor	75	1	Relay Packages	Relay Replacements
44		White Lake	375	5	Relay Packages	Relay Replacements
45		Cleveland	300	4	Relay Packages	Relay Replacements
46		Monitor	225	3	Relay Packages	Relay Replacements
47		Holland Road	675	9	Relay Packages	Relay Replacements
48		Dort	525	7	Relay Packages	Relay Replacements
49		**HVD System Protection Total**	**2,325**	**31**	Relay Packages	Relay Replacements
50		Wealthy (NESC Working Space)	900	15	Relay Packages	Relay Replacements and NESC Working Space

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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($000)

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2019 Test Year	(d) Units	(e) Unit Type	(f) Investment Category
1	Substation Communication Upgrades					
2		WD0131 GREY IRON ANALOG MULTI-DROP REPL$	307			
3		WD0094 HODENPYL ANALOG MULTI-DROP REPL $	306			
4		WD0565 HOLLAND ROAD ANALOG MULTI-DROP RE	329			
5		WD0167 HSC ANALOG MULTI-DROP REPL $	306			
6		WD0684 IOSCO ANALOG MULTI-DROP REPL $	301			
7		WD1100 LINDBERGH ANALOG MULTI-DROP REPL	306			
8		WD1140 LUDINGTON PUMPED ST ANALOG MULTI-	308			
9		WD1169 MECOSTA ANALOG MULTI-DROP REPL $	309			
10		WD0190 MORROW ANALOG MULTI-DROP REPL $	306			
11		WD1161 OAKLAND ANALOG MULTI-DROP REPL $	218			
12		WD1073 OGEMAW ANALOG MULTI-DROP REPL	307			
13		WD0775 ROCKPORT ANALOG MULTI-DROP REPL	306			
14		WD1090 SCOTT LAKE ANALOG MULTI-DROP REPL	307			
15		WD2046 STERNBERG ANALOG MULTI-DROP REPL	329			
16		WD0670 STOVER ANALOG MULTI-DROP REPL $	307			
17		WD1083 SUMMERTON ANALOG MULTI-DROP REPL$	297			
18		WD1000 THETFORD ANALOG MULTI-DROP REPL $	308			
19		WD0076 TIPPY HYDRO ANALOG MULTI-DROP REP	311			
20		WD0958 LAYTON ANALOG MULTI-DROP REPL $	305			
21		WD0276 TWINING ANALOG MULTI-DROP REPL $	306			
22		WD1135 UPJOHN ANALOG MULTI-DROP REPL $	311			
23		WD1489 VERNON ANALOG MULTI-DROP REPL $	295			
24		WD1109 WACKERLY ANALOG MULTI-DROP REPL $	297			
25		WD1149 WASHTENAW ANALOG MULTI-DROP REPL	305			
26		WD0402 WAYLAND ANALOG MULTI-DROP REPL $	297			
27		WD0400 WHITING ANALOG MULTI-DROP REPL $	307			
28		WD2051 ADA COGE ANALOG MULTI-DROP REPL	328			
29		WD2086 ADRIAN ENERGY PLANT ANALOG MULTID	324			
30		WD2055 BRENT RUN ANALOG MULTI-DROP REPL	328			
31		WD2104 C&C GENERATING PLT ANALOG MULTIDR	329			
32		WD2062 FILER CITY ANALOG MULTIDROP REPL$	329			
33		WD0495 GAYLORD GEN STATION ANALOG MULTI-	302			
34		WD2080 GRAND BLANC GEN ANALOG MULTI-DROP	269			
35		WD2065 GRANGER COGEN ANALOG MULTI-DROP R	329			
36		WD2064 GRAYLING COGEN ANLOG MULTI-DROP R	329			
37		WD2047 HILLMAN COGEN ANALOG MULTIDROP RE	329			
38		WD2052 KENT COUNTY COGEN ANLOG MULTIDROP	311			

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2019 Test Year	(d) Units	(e) Unit Type	(f) Investment Category
1	Substation Communication Upgrades					
2		WD0049 LOUD HYDRO ANALOG MULTI-DROP REPL	311			
3		WD0937 MENASHA ANALOG MULTI-DROP REPL	329			
4		WD2081 MICHIGAN POWER ANALOG MULTIDROP R	308			
5		WD2077 OTTAWA GENERATING ANALOG MULTI-DR	329			
6		WD2093 PEOPLES GENERATING ANALOG MULTI-D	324			
7		WD0021 ROGERS HYDRO ANALOG MULTIDROP REP	311			
8		WD1173 STRAITS PLANT ANALOG MULTI-DROP R	329			
9		WD2149 VENICE PARK WEST ANALOG MULTI-DRO	307			
10		WD2056 VIKING LINCOLN ANALOG MULTIDROP R	329			
11		WD2054 VIKINGMCBAI ANALOG MULTIDROP REPL	329			
12		WD0022 WEBBER DAM ANALOG MULTI-DROP REPL	300			
13		WD2123 ZEELAND GEN ANALOG MULTI-DROP REP	311			
14		WD0325 BOSTON SQUARE ANALOG MULTI-DROP R	306			
15		WD1242 BRETON ANALOG MULTI-DROP REPL	309			
16		WD0035 CADILLAC ANALOG MULTI-DROP REPL	300			
17		WD0142 CANNON ANALOG MULTI-DROP REPL $	298			
18		WD0658 COLDBROOK ANALOG MULTI-DROP REPL	309			
19		WD0369 COOLEY ANALOG MULTI-DROP REPL	297			
20		WD0191 CROTTY ANALOG MULTI-DROP REPL	319			
21		WD0949 CUMBERLAND ANALOG MULTI-DROP REPL	319			
22		WD0473 DIETZ ROAD ANALOG MULTI-DROP REPL	301			
23		WD0806 EATON RAPIDS MUNICIP ANALOG MULTI	320			
24		WD0562 ENGINE PLANT ANALOG MULTI-DROP RE	297			
25		WD0440 FAIRBANKS ANALOG MULTI-DROP REPL	297			
26		WD0596 FRAME PLANT ANALOG MULTI-DROP REP	295			
27		WD0145 GREENVILLE ANALOG MULTI-DROP REPL	315			
28		WD0979 HALSEY ANALOG MULTI-DROP REPL$	297			
29		WD0338 HARRISON ANALOG MULTI-DROP REPL	324			
30		WD0110 HASTINGS ANALOG MULTI-DROP REPL	302			
31		WD0599 HEMLOCK ANALOG MULTI-DROP REPL	319			
32		WD0203 LAKE SHORE ANALOG MULTI-DROP REPL	315			
33		WD0765 LOVELL ANALOG MULTI-DROP REPL	300			
34		WD0088 QUINCY ANALOG MULTI-DROP REPL	307			
35		WD0161 ROCHESTER PRODUCTS ANALOG MULTI-D	311			
36		WD1002 SHAFFER ANALOG MULTI-DROP REPL	297			
37		WD0768 SILICON ANALOG MULTI-DROP REPL	310			
38		WD1129 SPARTAN ANALOG MULTI-DROP REPL	306			
39		WD0745 STATE HOSPITAL ANALOG MULTI-DROP	308			
40		WD0359 TECUMSEH PRODUCTS ANALOG MULTI-DR	312			
41		WD1262 TIHART ANALOG MULTIDROP REPL $	306			
42		WD0547 VAN SLYKE ANALOG MULTI-DROP REPL	298			
43		WD0070 WATER STREET ANALOG MULTI-DROP RE	319			
44		WD0281 WHITESTONE POINT ANALOG MULTI-DRO	319			
45		WD0798 ANTRIM ANALOG MULTI-DROP REPL	310			

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($000)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected 2019 Test Year**	**Units**	**Unit Type**	**Investment Category**
1	Substation Communication Upgrades					
2		WD0545 ASYLUM ANALOG MULTI-DROP REPL	302			
3		WD0727 BURLINGAME ANALOG MULTI-DROP REPL	325			
4		WD0102 GRAND LEDGE ANALOG MULTIDROP REPL	305			
5		WD0170 HARVEY STREET ANALOG MULTI-DROP R	322			
6		WD0492 HASKELITE ANALOG MULTI-DROP REPL	319			
7		WD0074 HUDSON ANALOG MULTI-DROP REPL	324			
8		WD1449 IVA ROAD ANALOG MULTI-DROP REPL	323			
9		WD0212 PHILLIPS ANALOG MULTI-DROP REPL	324			
10		WD0341 POTTER ANALOG MULTI-DROP REPL	308			
11		WD0999 RICKERT ANALOG MULTI-DROP REPL	321			
12		WD0589 THORNAPPLE ANALOG MULTI-DROP REPL	322			
13		WD0362 WASHINGTON ANALOG MULTI-DROP REPL	307			
14		WD0176 WESTERN AVENUE ANALOG MULTI-DROP	300			
15		WD1108 WILLIAMS ANALOG MULTI-DROP REPL	307			
16		WD0235 BEALS ROAD ANALOG MULTI-DROP REPL	310			
17		WD0725 BEGOLE ANALOG MULTIDROP REPL $	306			
18		WD0211 BLACK RIVER ANALOG MULTI-DROP REP	306			
19		WD0132 CALHOUN ANALOG MULTI-DROP REPL $	307			
20		WD0151 DELHI ANALOG MULTI-DROP REPL $	324			
21		WD0136 EDENVILLE DAM ANALOG MULTI-DROP R	299			
22		WD0433 FOUR MILE ANALOG MULTI-DROP REPL	328			
23		WD1117 LAWNDALE ANALOG MULTIDROP REPL $	310			
24		WD0095 CROTON ANALOG MULTIDROP REPL $	328			
25		WD0640 MARQUETTE ANALOG MULTI-DROP REPL	323			
26		WD0032 MIO DAM ANALOG MULTI-DROP REPL	329			
27		WD0270 NORTH BELDING ANALOG MULTI-DROP R	308			
28		WD1250 RANSOM ANALOG MULTIDROP REPL $	305			
29		WD0980 SPAULDING ANALOG MULTI-DROP REPL$	327			
30		WD0286 VERONA ANALOG MULTI-DROP REPL $	307			
31		WD0195 WEADOCK J C PLANT ANALOG MULTI-DR	304			
32		WD0201 EDMORE ANALOG MULTI-DROP REPL	317			
33		WD1082 GOODALE ANALOG MULTI-DROP REPL	325			
34		WD0705 KALKASKA ANALOG MULTI-DROP REPL	329			
35		WD0763 KELLOGG ANALOG MULTI-DROP REPL	325			
36		WD0297 LAMBERTVILLE ANALOG MULTI-DROP RE	326			
37		WD0405 LASALLE ANALOG MULTI-DROP REPL	329			
38		WD0231 MENDON ANALOG MULTI-DROP REPL	325			
39		WD0807 PERKEY RD ANALOG MULTI-DROP REPL	329			
40		WD0742 POST CEREAL ANALOG MULTI-DROP REP	325			
41		WD0156 BROWNPAPER ANALOG MULTI-DROP REPL	329			
42		WD0264 NORTHLANSING ANALOG MULTIDROP REP	325			
43		WD0351 BELSAY ANALOG MULTI-DROP REPL	330			
44		WD0882 CARY ROAD MOAB ANALOG MULTI-DROP	330			
45		WD0062 GRAND BLANC ANALOG MULTI-DROP REP	330			
46		WD1427 IRISH ROAD ANALOG MULTI-DROP REPL	330			
47		WD1277 LEVELY ANALOG MULTI-DROP REPL	330			
48		WD1595 PEARLINE ANALOG MULTI-DROP REPL	330			
49		WD1523 SINCLAIR ANALOG MULTI-DROP REPL	330			
50		WD0696 SUPPLY DEPOT ANALOG MULTI-DROP RE	330			
51		WD0084 KARN SUB ANALOG MULTI-DROP REPL $	329			
52		**Substation Communication Upgrades Total**	**41,034**			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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For the Test Year 12 Months Ending December 31, 2019
($000)

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected 2019 Test Year**	**Units**	**Unit Type**	**Investment Category**
1	HVD Capacity					
2		WD0000 NEW 138/46 COOPERSVILLE/RAVENNA	3,446			Load Carrying Capabilities and Voltage Support
3		LN063E STERNS RD LINE RBLD 2.1 MI 46KV	1,700			Load Carrying Capabilities and Voltage Support
4		LN_ NEW 138/46 COOPERSVILLE/RAVENNA 46kV LINE	1,569			Load Carrying Capabilities and Voltage Support
5		LN063J JACKMAN LINE RBLD 3.3 MI 46KV	1,500			Load Carrying Capabilities and Voltage Support
6		WD0190 MORROW REPL 156 VARMASTER	383			Load Carrying Capabilities and Voltage Support
7		WD0560 RIVERVIEW REPL 156 VARMASTER	338			Load Carrying Capabilities and Voltage Support
8		WD1085 AMBER REPL 156 VARMASTER	255			Load Carrying Capabilities and Voltage Support
9		LN_SEVEN MILE SUB 138 KV LINE	3,075			New Interconnections
10		LN_STONEY CORNERS - NEW 69kV SPUR	900			New Interconnections
11		LN0008AO_KROMDYKE - NEW 138kV SPUR	900			New Interconnections
12		LN019W MECOSTA RBLD 1.1 MI 46 kV %	284			New Interconnections
13		LN018C ONEKAMA, NEW 46kV SWS	240			New Interconnections
14		LN044AF RANKIN NEW 46kV TAP & SW	150			New Interconnections
15		LN071TT - TEMPORARY 46kV SUB TAP (MDOT)	113			New Interconnections
16		LN018_ HIGH BRIDGE, NEW 46kV TAP	90			New Interconnections
17		LN0019D NEWAYGO_RETIRE STR#129 - #138	15			New Interconnections
18		LN0019J NEWAYGO_RETIRE STR#129 - #138-1	15			New Interconnections
19		LN018C ONEKAMA, REM 6409 & 6421 SWS	15			New Interconnections
20		LN018G KALEVA SPUR REM 46KV TAP	15			New Interconnections
21		WD1489 VERNON ADD 4 BKRS 46KV	1,050			Improved Functionality
22		WD0565 Holland Rd Repl 399 SOGS w CKT SWR	278			Improved Functionality
23		LN015E UPTON 46KV RBLD 7.0MI METC COORD.	1,735			Coordinate with Transmission
24		WD1249 ALGOMA INST DUAL PILOT RLY & CCVT	570			Coordinate with Transmission
25		WD0387 DORT REPL 199 AND 299 BKRS	375			Coordinate with Transmission
26		WD0190 MORROW MODIFY RELAYING FOR METC	213			Coordinate with Transmission
27		WD0190 MORROW RELO FENCE FOR METC$	98			Coordinate with Transmission
28		ELECTRIC DISTRIBUTION EASMENTS	1,622			Right of Way Procurement
29		LN033CA ROSEBUSH R/W 46KV 8MI	625			Right of Way Procurement
30		LN_ SEVEN MILE SUB 138KV LINE R/W	323			Right of Way Procurement
31		LN033Y FROST R/W 46KV 1 MI	175			Right of Way Procurement
32		LN033KK SURREY R/W 46KV 0.3 MI	110			Right of Way Procurement
33		ELECTRIC FRANCHISE & CONSENT	10			Right of Way Procurement
34		WD1267 TAMARACK-LAKEVIEW ISOLATOR RIGHTS	1			Right of Way Procurement
35		**HVD Capacity Total**	**22,188**			
36		WD0560 RIVERVIEW NEW 46KV CCH WORK SPACE (NESC Working Space)	1,125			Improved Functionality NESC Working Space
37		WD0605 WEXFORD INST NEW CCH (NESC Working Space)	715			Improved Functionality NESC Working Space
38		WD0999 RICKERT INST NEW CCH & REPL PNLS (NESC Working Space)	420			Improved Functionality NESC Working Space

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2019 Test Year	(d) Units	(e) Unit Type	(f) Investment Category
1	LVD Substation Capacity					
2		Seven Mile	1,700			New Substations
3		Beaver Creek	1,500			New Substations
4		Case Lake	1,500			New Substations
5		Kromdyke	1,200			New Substations
6		Paradise	2,000			New Substations
7		Stoney Corners	2,000			New Substations
8		Bagley	750			Increase Capacity at Existing Substation
9		Harvey Street	98			Increase Capacity at Existing Substation
10		Keating	75			Increase Capacity at Existing Substation
11		Lagrave	450			Increase Capacity at Existing Substation
12		Millers Point	375			Increase Capacity at Existing Substation
13		Morenci	1,500			Increase Capacity at Existing Substation
14		**LVD Substation Capacity Total**	**13,148**			
15	System Control Projects					
16		Disposal Plant 177 & 188	45			Upgrade to enable remote control and monitoring
17		Homestead 46kV Line	75			Minimize the need and the impact to customers of cutting jumpers at this location by: Installing a switch to this line.
18		Hughes Road 46kV Line	263			Enable line to be used to remediate high load contingencies by: Re-building 0.78 miles of the existing line using a higher capacity conductor.
19		Hurley177 & 188	45			Upgrade to enable remote control and monitoring
20		Isabella 477 & 488	45			Upgrade to enable remote control and monitoring
21		Kearsley 277 & 377	45			Upgrade to enable remote control and monitoring
22		Kellogsville 277 & 377	45			Upgrade to enable remote control and monitoring
23		Kent City 277 & 288	45			Upgrade to enable remote control and monitoring
24		Kings Corner 388 & 488	45			Upgrade to enable remote control and monitoring
25		Merson 188	188			New installation of a switching device with remote control and monitoring enabled resulting in faster restoration times.
26		Metro 46KV Line	45			Upgrade to enable remote control and monitoring
27		Petoskey 46kV Line	75			Minimize the need and the impact to customers of cutting jumpers at this location by:- Installing a switch to this line.
28		Ravenna - Apple	23			Upgrade to enable remote control and monitoring
29		Ravenna - Ravenna	23			Upgrade to enable remote control and monitoring
30		Saginaw Street 288 & 277	375			New installation of two switching devices with remote control and monitoring enabled resulting in faster restoration times.
31		Shepherd 277	23			Upgrade to enable remote control and monitoring
32		South Washington 277 & 677	45			Upgrade to enable remote control and monitoring
33		Stanley 46kV Line	75			Increase the capacity Line by 48% by:- Replacing one switch to a higher capacity switch type.
34		Temprance 277 & 288	45			Upgrade to enable remote control and monitoring
35		Vandercook Lake 188	23			Upgrade to enable remote control and monitoring
36		Wolverine 5788 & 5776	45			Upgrade to enable remote control and monitoring
37		Office Expansion and Technology	415			
38		**System Control Projects Total**	**2,050**			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Division - HVD
Summary of Actual and Projected Electric & Common O&M Expenses
For the Year 2018 and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-25 (JRA-10)
Page: 1 of 2
Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos. Ending 12/31/2017**	**12 Mos. Ended 12/31/2018**	**12 Mos. Ending 12/31/2019**	**Source**
1	Electric Division Expenses - HVD	$ 36,728	$ 36,257	$ 38,255	
2	Smart Energy Direct O&M Benefits	-	-	-	
3					
4	**Total Expense**	**$ 36,728**	**$ 36,257**	**$ 38,255**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Division - HVD
Summary of Actual and Projected Electric & Common O&M Expenses
For the Year 2018 and Test Year 12 Months Ending December 31, 2019
($000)

Line No.	(a) Description	(b) Historical Labor 12 Mos. Ended 12/31/2017	(c) Historical Non-Labor 12 Mos. Ended 12/31/2017	(d) Historical Total 12 Mos. Ended 12/31/2017	(e) Projected Labor 12 Mos. Ending 12/31/2018	(f) Projected Non-Labor 12 Mos. Ending 12/31/2018	(g) Projected Total 12 Mos. Ending 12/31/2018	(h) Projected Labor 12 Mos. Ending 12/31/2019	(i) Projected Non-Labor 12 Mos. Ending 12/31/2019	(j) Projected Total 12 Mos. Ending 12/31/2019	(k) Source
1	Electric Division Expenses - HVD	$ 18,981	$ 17,747	$ 36,728	$ 19,885	$ 16,372	$ 36,257	$ 20,871	$ 17,384	$ 38,255	
2	Smart Energy Direct O&M Benefits	-	-	-	-	-	-	-	-	-	
3											
4	**Total Expense**	**$ 18,981**	**$ 17,747**	**$ 36,728**	**$ 19,885**	**$ 16,372**	**$ 36,257**	**$ 20,871**	**$ 17,384**	**$ 38,255**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Operations - HVD and Electric Engineering & Support - HVD
Summary of Actual and Projected Electric & Common O&M Expenses
For the Year 2018 and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-26 (JRA-11)
Page: 1 of 1
Witness: JRAnderson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos. Ended 12/31/2017**	**12 Mos. Ending 12/31/2018**	**12 Mos. Ending 12/31/2019**	**Source**
1	Electric Operations - HVD	$ 31,806	$ 32,437	$ 32,851	
2	Electric Engineering & Support - HVD	4,922	3,820	5,404	
3					
4	**Electric Division Expenses - HVD**	**$ 36,728**	**$ 36,257**	**$ 38,255**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Division Programs
Summary of Actual and Projected Electric & Common O&M Expenses
For the Year 2018 and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-27 (JRA-12)
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Witness: JRAnderson
Date: May 2018

Electric Division Programs

Line No.	(a) **Description**	(b) **2017 Actual**	(c) **2018 Projected**	(d) **2019 Projected**
1	Lines Reliability - HVD	147	125	125
2	Substations Reliability - LVD	1,697	1,618	1,618
3	Substations Reliability - HVD	1,145	1,282	1,282
4	Forestry - HVD	11,394	10,140	10,200
5	**Reliability**	**14,383**	**13,165**	**13,225**
6	Lines Demand - HVD	785	750	798
7	Substations Demand - LVD	2,728	3,100	3,162
8	Substations Demand - HVD	2,054	2,111	2,151
9	Alma Equipment Repair	1,058	1,173	1,174
10	**Ops, Maint and Metering**	**6,625**	**7,134**	**7,285**
11	Supervision/Admin - Staff	6,725	7,147	7,343
12	**Field Operations Services**	**6,725**	**7,147**	**7,343**
13	**Grid Management**	**4,073**	**4,991**	**4,998**
14	**Electric Operations - HVD**	**31,806**	**32,437**	**32,851**
15	Rate Case Administration	95	84	87
16	Regulatory & Compliance	721	193	199
17	Electric Engineering - HVD	4,106	3,543	5,118
18	**Electric Engineering & Support - HVD**	**4,922**	**3,820**	**5,404**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
5yr Historical
Summary of Actual and Projected Electric & Common O&M Expenses
For the Historic Actuals, Year 2018 and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-28 (JRA-13)

Witness: JRAnderson
Date: May 2018

Electric Division Programs

Line No.	Description (a)	2013 Actual (b)	2014 Actual (c)	2015 Actual (d)	2016 Actual (e)	2017 Actual (f)	5-Year Average (g)	2018 Projected (h)	2019 Projected (i)	2019 vs. 5-Year Average (j)
1	Lines Reliability - HVD	646	628	236	317	147	395	125	125	(270)
2	Substations Reliability - LVD	1,547	1,999	1,549	1,794	1,697	1,717	1,618	1,618	(99)
3	Substations Reliability - HVD	1,193	839	1,069	957	1,145	1,041	1,282	1,282	241
4	Forestry - HVD	3,945	6,295	5,718	9,468	11,394	7,364	10,140	10,200	2,836
5	**Reliability**	**7,331**	**9,761**	**8,572**	**12,536**	**14,383**	**10,517**	**13,165**	**13,225**	**2,708**
6	Lines Demand - HVD	3,243	2,007	1,167	533	785	1,547	750	798	(749)
7	Substations Demand - LVD	3,197	3,748	3,393	3,321	2,728	3,277	3,100	3,162	(115)
8	Substations Demand - HVD	2,277	2,826	2,420	2,150	2,054	2,345	2,111	2,151	(194)
9	Alma Equipment Repair	1,032	1,248	980	1,136	1,058	1,091	1,173	1,174	83
10	**Ops, Maint and Metering**	**9,749**	**9,829**	**7,960**	**7,140**	**6,625**	**8,261**	**7,134**	**7,285**	**(976)**
11	Supervision/Admin - Staff	5,988	6,586	6,556	6,063	6,725	6,384	7,147	7,343	959
12	**Field Operations Services**	**5,988**	**6,586**	**6,556**	**6,063**	**6,725**	**6,384**	**7,147**	**7,343**	**959**
13	**Grid Management**	**3,179**	**2,628**	**2,807**	**2,778**	**4,073**	**3,093**	**4,991**	**4,998**	**1,905**
14	**Electric Operations - HVD**	**26,247**	**28,804**	**25,895**	**28,517**	**31,806**	**28,254**	**32,437**	**32,851**	**4,597**
15	Rate Case Administration	61	53	51	24	95	57	84	87	30
16	Regulatory & Compliance	12	79	37	112	721	192	193	199	7
17	Electric Engineering - HVD	6,303	6,362	6,452	6,299	4,106	5,904	3,543	5,118	(786)
18	**Electric Engineering & Support - HVD**	**6,376**	**6,494**	**6,540**	**6,435**	**4,922**	**6,153**	**3,820**	**5,404**	**(749)**
	Total O&M - HVD	**32,623**	**35,298**	**32,435**	**34,952**	**36,728**	**34,407**	**36,257**	**38,255**	**3,848**

2016 Loss Study Report

Apr. 20, 2018

Introduction

The purpose of this study is to allocate system energy and demand losses among the various components of the electric system by calculating a percentage Loss Factor for each system component. This information will be used to update loss calculations used in electric rate design. Customer and Service Infrastructure - HVD calculated Loss Factors for the 345, 138 and 46 kV systems and the low side of the 138 and 46 kV industrial systems. The Loss Factor for the Distribution Primary system was calculated with input from Customer and Service Infrastructure - LVD. Finally, the Loss Factor for the Distribution Secondary system (including secondary transformers) was calculated from the amount of system loss remaining after all other system component losses were allocated.

Definitions:

1. **System Component Losses:** Generated and purchased (“input” or “delivery”) Power or Energy (including imports) minus consumed or distributed (“output”) Power or Energy.

   Note: *The total generated and purchased energy megawatt-hours (MWh) for 2016 and the total MWh delivered (sold) at each component during 2016 were provided by the Accounting Dept. and Rates Dept., respectively. The overall electric system loss percentage is derived from the generated and purchased energy data rather than from system models.*

2. **Loss Factor (%):**
   $$\left[1-\frac{\text{COMPONENT OUTPUT POWER/ENERGY}}{\text{COMPONENT INPUT POWER/ENERGY}}\right]\times 100\% = \left[\frac{\text{COMPONENT POWER/ENERGY LOSS}}{\text{COMPONENT INPUT POWER/ENERGY}}\right]\times 100\%$$

3. **Efficiency Factor:** [100% - Loss Factor (%)] or [1 – Loss Factor $_{\text{p.u.}}$]

4. **Energy Loss Factor:** Total System Component MWh Loss divided by Total System Component MWh Input

5. **Demand Loss Factor:** Average of Monthly Peak System Component MW Losses divided by Monthly Peak System Component MW Inputs.
   Note: *Average based on twelve monthly peak hours as identified in FERC Form 1, Page 401b*

6. **Cumulative Loss Factor (Energy or Demand):** One minus the product of one minus the per-unit Loss Factor for that system component and one minus the per-unit loss factor for each of the upstream system components. Or, one minus the product of the per-unit efficiency factors for the system component and all upstream system components.

   Note: *Cumulative loss factors are used to estimate the generation requirements necessary to serve a particular amount of load at any system component.*

Energy Losses - Method

1. Loadflow model cases were created for each of the 8784 hours in 2016. Software developed by the Models and Dynamics group extracted data for losses and deliveries at various points of the electric Transmission and High Voltage Distribution (HVD) systems from each loadflow case (*i.e.* each hour).

2. Utilizing the MWh loss and delivery data, loss percentages for each Transmission or HVD system component were then calculated as:

$$\frac{\sum \text{Component MWh Loss}}{\sum \text{Component MWh Delivery}}$$

3. For Distribution Primary, average load and loss data from approximately 400 representative circuits at nine different system gross load levels for all-switched-capacitors-on and all-switched-capacitors-off scenarios were provided by Customer and Service Infrastructure - LVD Substation Planning. A line loss percentage was calculated from load and loss figures interpolated between the caps-on and caps-off data, based on the per system load level distribution capacitor schedule (tone groups). The line loss, along with Distribution Primary transformer losses calculated in the hourly loadflow cases, comprise the total losses for Distribution Primary.

4. For Distribution Secondary, sales (output) data per system component were provided by Rates Dept. Generation requirements (input) per system component were estimated based on cumulative loss percentages previously calculated for each of the other system components. Total system generation requirements were estimated based on an overall system loss percentage derived from Generation and Purchased Power data provided by Accounting Dept. The difference between the total system estimated generation requirements and the sum of the estimated generation requirements for each system component (except for Distribution Secondary) gives the estimated generation requirement for Distribution Secondary. The difference between Distribution Secondary estimated generation requirements and Distribution Secondary sales gives a cumulative loss percentage, from which the Distribution Secondary loss percentage was derived.

Demand Losses - Method

1. The loss and delivery data from the loadflow cases for the 12 monthly peak hours, as identified in FERC Form 1, were selected and the loss percentages for each Transmission or HVD system component were calculated as the average of ratios of losses to deliveries:

$$\overline{\left[\frac{\text{MW Loss}_{\text{pk}}}{\text{MW Delivery}_{\text{pk}}}\right]}$$

2. For Distribution Primary, demand line loss percentages for each of the 12 monthly peak hours were calculated similarly as for energy loss. Demand loss percentages were calculated as the average of the loss to delivery ratios, as with the Transmission and HVD system components.

3. For Distribution Secondary, the ratios of monthly peak gross MW sendouts to the hourly average gross MW sendout were used to estimate an average monthly peak MW delivery per system component. Similar to Distribution Secondary energy loss calculations, an average of monthly peak generation was then estimated from the system component cumulative demand loss percentages. Distribution Secondary average peak generation and, subsequently, cumulative demand loss percentage were estimated, similarly as with energy losses. From that, the Distribution Secondary demand loss percentage was derived. See “Losses Applied to MWh Deliveries,” below.

Demand Losses – Method, continued

4. Monthly peak demand MW deliveries and losses are tabulated for each system component. The loss factors and cumulative loss factors for each of the 12 monthly peaks were calculated using the previously described methods. For Distribution Secondary, the annual Demand Loss Factor was applied to each of the monthly peak MW deliveries to estimate monthly peak losses and monthly peak Cumulative Loss Factors. Using the annual Distribution Secondary Loss Factor in this manner was necessary since the MWh sales figures used to estimate Distribution Secondary losses is available on an annual, not monthly, basis.

Losses Applied to MWh Deliveries

1. The cumulative Loss Factors at each system component (Energy and Demand, in per-unit) were used to estimate the generation necessary to provide the given delivery to that system component, per the following formula:

$$\text{Generation} = \frac{\text{Delivery}}{\text{1-Loss Factor}_{\text{p.u.}}}$$

2. The difference between the total power generated and purchased (for the entire system) and the sum of the generation requirements for all system components except Distribution Secondary yielded the cumulative losses for Distribution Secondary. The Loss Factor for Distribution Secondary was then found by rearranging the definition for cumulative losses, as follows:

$$\text{Loss Factor}_{Sec.Dist.,p.u.} = 1 - \frac{1 - \text{Cum. Loss Factor}_{Sec.Dist.,p.u.}}{1 - \text{Cum. Loss Factor}_{Prim.Dist.,p.u.}}$$

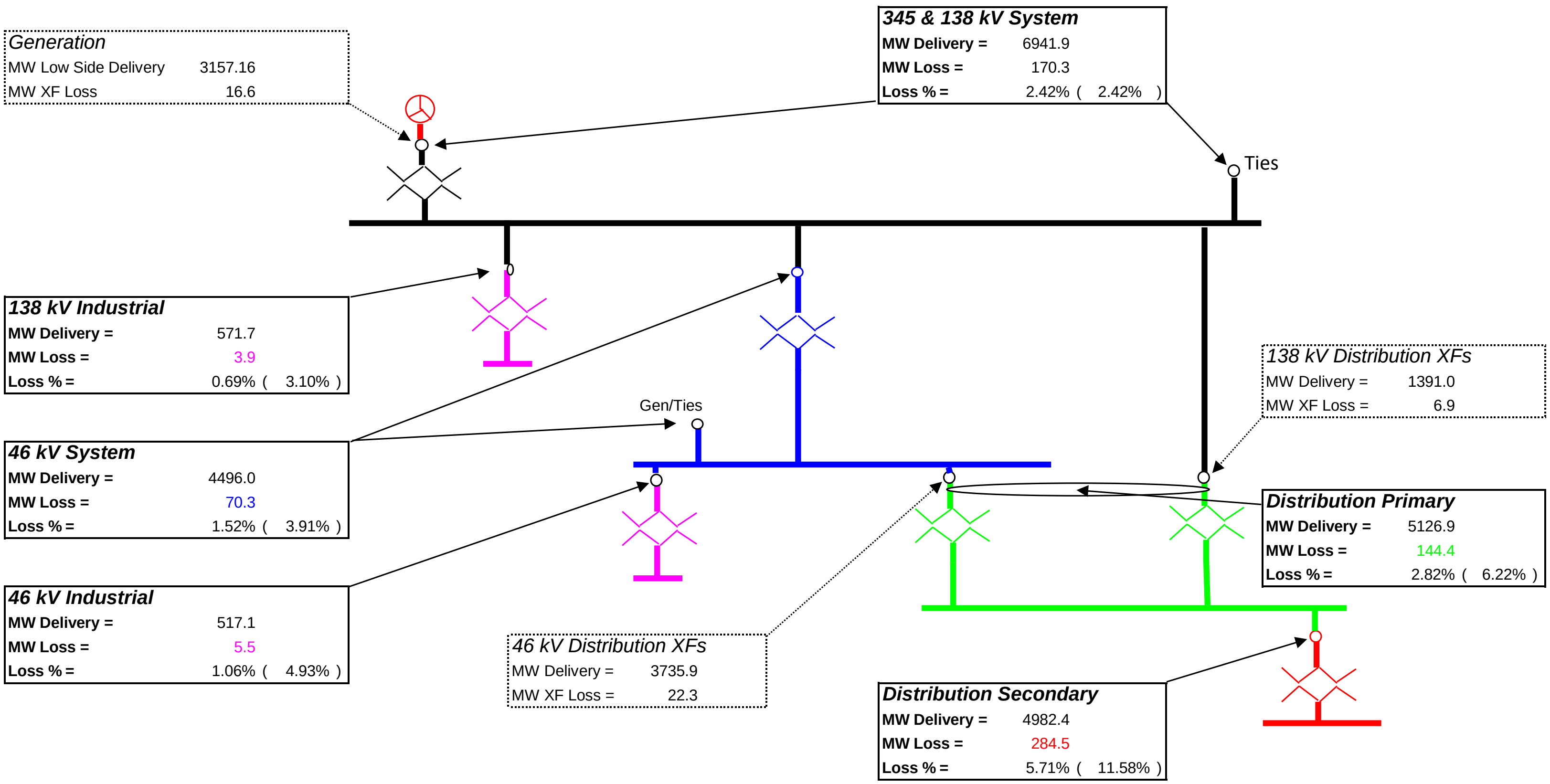
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20134
Exhibit No.: A-29 (JRA-14)

Witness: JRAnderson
Date: May 2018

2016 SYSTEM LOSS STUDY -- DEMAND LOSSES AND DELIVERIES (AVERAGE OF 12 MONTHLY PEAKS)

Combined Method (Each Component Includes Transformation to that Component)



General Notes

- Each separate component is color-coded, arrows indicate point of delivery
- Loss %'s in parentheses are the Cumulative Loss %'s.
- Loss %'s are calculated as Loss % = (MW Loss/MW Delivery)*100%
- Cumulative Loss %'s are calculated as one minus the product of one minus the Loss %(pu) for that component and all higher components.
- Loss % for Distribution Primary Lines (2.26%) provided by C&SI - LVD
- Generation Transformers were combined with the 345 & 138 kV system because all customers are connected at lower voltages (components).

Notes for Distribution Primary and Secondary

- MW Delivery is high-side sum of 138/DST and 46/DST XFs
- MW Loss includes 138 & 46 /DST XF AND primary line loss
- Cumulative Loss % is adjusted based on the weighted average amount of load served from 138 kV and 46 kV
  First, [(3736)*3.91%+(1391)*2.42%]/(3736+1391)=3.50%
  Then, [1-(1-0.0282)*(1-0.0350)]*100%=6.22%
- Distribution Secondary cumulative demand loss % estimated using the average monthly peak deliveries. Refer to estimating sheet.

2016 SYSTEM LOSS STUDY -- CUMULATIVE DEMAND LOSS PERCENTAGES APPLIED TO MWh DELIVERIES

Combined Method (Each Component Includes Transformation to that Component)

Electrical System Voltage Level	MWh Deliveries (Total)[5]	Average Hourly MW Delivery	Estimated Average Monthly Peak MW Delivery	Cumulative % Demand Loss[4]	MW @ Generation	% Demand Losses	
138 kV System	762,614	86.82	119	2.42%	122	2.42%	Generation Transformers, 345 &138 kV Systems Combined
V1: >120kV[1]	4,395,256	500.37	686	3.10%	708	0.69%	Cum(%) = [1-(1-138IND%)*(1-138Sys_cum%)]*100%
46 kV System[1]	411,175	46.81	64	3.91%	67	1.52%	Cum(%) = [1-(1-46Sys%)*(1-138Sys_cum%)]*100%
V2: 25kV - 120kV[1]	3,540,400	403.05	552	4.93%	581	1.06%	Cum(%) = [1-(1-46IND%)*(1-46Sys_cum%)]*100%
V3: <25kV, Primary Distribution[1&2]	8,154,860	928.38	1272	6.22%	1357	2.82%	Cum(%) = [1-(1-DSTprimary%)*(1-46&138AVG_cum%)]*100% (2)
V4: Secondary Distribution[1,2&3]	20,701,679	2356.75	3230	11.58%	3653	5.71%	Cum(%) = [(MWh Gen - MWh Del)/MWh Gen]*100% (3)
	37,965,983	4322	5923	8.68%	6487		

NOTE:

1. The cumulative loss for any level is equal to one minus the product of one minus the loss % for that level and one minus the cumulative loss % one level higher.

2. The Cumulative Loss Percentages for the Distribution Primary and Secondary were adjusted to account for load served from 138 kV distribution subs. This adjustment was based on a weighted average cumulative loss % from the total MWh delivered to either 46kV/Dist. or 138/Dist.

3. The Distribution Secondary Cumulative Loss % was calculated from the MWh Gen and MWh Del remaining. Then the Energy Loss % was calculated in reverse from the cumulative.

4. All cumulative loss %s are calculated assuming the 345 kV and 138 kV Systems are combined along with the Generation Transformers (GSUs)

5. MWh Delivery figures include ROA amounts.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

2016 SYSTEM LOSS STUDY - MONTHLY DEMAND LOSSES AND DELIVERIES

Combined Method (Each Component Includes Transformation to that Component)

	PEAKS	Jan 11, 2016 19:00	Feb 10, 2016 20:00	Mar 1, 2016 20:00	Apr 4, 2016 10:00	May 26, 2016 16:00	Jun 20, 2016 16:00	Jul 22, 2016 16:00	Aug 11, 2016 15:00	Sep 6, 2016 16:00	Oct 17, 2016 19:00	Nov 21, 2016 19:00	Dec 19, 2016 19:00
GENERATION	Deliveries (MW)	3230.8	3081.8	2963.5	1598.2	2854.8	3017.6	3062.3	4213.2	3997.5	3916.7001	2481.4	3468.1
	Losses (MW)	17.3	17.2	16.5	13.0	14.9	17.5	18.0	21.1	20.3	15.6	12.5	15.8
345&138 KV SYSTEM	Deliveries (MW)	6601.5	6434.1	6063.8	5869.7	6933.9	7982.1	8325.0	8660.3	8282.3	5670.6	6049.5	6430.1
	Losses (MW)	158.3	122.2	105.8	111.3	156.0	199.7	227.9	259.2	237.2	182.3	129.9	153.5
	Loss Factor	2.40%	1.90%	1.74%	1.90%	2.25%	2.50%	2.74%	2.99%	2.86%	3.21%	2.15%	2.39%
138 KV INDUSTRIAL	Deliveries (MW)	581.0	612.8	587.8	557.2	583.7	591.9	578.2	588.0	421.4	601.7	581.7	575.5
	Losses (MW)	3.8	4.0	3.9	3.8	3.9	4.1	3.9	4.0	3.9	4.1	3.8	3.9
	Loss Factor	0.66%	0.65%	0.67%	0.69%	0.67%	0.68%	0.68%	0.68%	0.93%	0.68%	0.66%	0.68%
	Cumulative Loss Factor[2]	3.04%	2.54%	2.40%	2.57%	2.91%	3.17%	3.39%	3.65%	3.77%	3.87%	2.79%	3.05%
46 KV SYSTEM	Deliveries (MW)	4108.2	3797.0	3787.6	3498.6	4430.8	5286.8	5690.0	5922.5	5715.8	3723.4	3740.5	4251.0
	Losses (MW)	57.6	51.5	50.1	43.9	64.9	89.9	104.5	111.7	104.2	52.1	51.0	62.1
	Loss Factor	1.40%	1.36%	1.32%	1.26%	1.46%	1.70%	1.84%	1.89%	1.82%	1.40%	1.36%	1.46%
	Cumulative Loss Factor[2]	3.77%	3.23%	3.04%	3.13%	3.68%	4.16%	4.52%	4.82%	4.63%	4.57%	3.48%	3.81%
46 KV INDUSTRIAL	Deliveries (MW)	487.6	496.4	482.1	497.1	513.1	546.1	549.7	576.7	564.3	542.8	468.3	481.4
	Losses (MW)	5.3	5.3	5.2	5.3	5.5	5.6	5.8	5.9	5.9	5.6	5.2	5.3
	Loss Factor	1.09%	1.07%	1.08%	1.06%	1.07%	1.03%	1.05%	1.02%	1.04%	1.04%	1.12%	1.10%
	Cumulative Loss Factor[2]	4.81%	4.27%	4.09%	4.16%	4.71%	5.15%	5.52%	5.79%	5.63%	5.56%	4.56%	4.88%
138 KV DISTRIBUTION	Deliveries (MW)	1175.0	1399.1	1273.9	1181.4	1509.2	1620.5	1784.0	1848.1	1676.9	1169.0	1004.4	1051.0
	Losses (MW)	5.4	7.0	6.0	5.5	7.8	8.3	9.6	9.8	8.6	5.3	4.5	4.7
46 KV DISTRIBUTION	Deliveries (MW)	3401.8	3101.3	3104.9	2813.4	3684.6	4443.7	4811.9	5017.2	4853.6	2985.9	3072.4	3539.5
	Losses (MW)	19.3	17.9	17.6	16.3	21.4	27.2	30.3	32.1	31.0	16.9	17.9	20.3
DISTRIBUTION PRIMARY	Deliveries (MW)	4576.8	4500.4	4378.8	3994.8	5193.8	6064.1	6595.8	6865.3	6530.6	4154.9	4076.8	4590.5
	Losses (MW)	118.7	115.4	107.3	96.0	146.5	194.9	223.9	241.6	216.0	102.3	99.8	120.3
	Loss Factor	2.59%	2.56%	2.45%	2.40%	2.82%	3.21%	3.39%	3.52%	3.31%	2.46%	2.45%	2.62%
	Cumulative Loss Factor[2]	5.92%	5.31%	5.05%	5.10%	5.99%	6.81%	7.30%	7.70%	7.35%	6.55%	5.52%	6.02%
DISTRIBUTION SECONDARY	Deliveries (MW)	4458.1	4385.0	4271.6	3898.8	5047.3	5869.2	6371.9	6623.7	6314.6	4052.6	3977.0	4470.2
	Losses (MW)	254.6	250.4	243.9	222.6	288.2	335.1	363.8	378.2	360.6	231.4	227.1	255.2
	Loss Factor[1]	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%
	Cumulative Loss Factor[2]	11.29%	10.71%	10.47%	10.52%	11.36%	12.13%	12.59%	12.97%	12.64%	11.88%	10.92%	11.38%

NOTE:

1. The Distribution Secondary Loss Factor presented above represents an annual average loss percentage. This Loss Factor is applied to each of the 12 monthly peaks to estimate monthly peak demand losses and cumulative demand Loss Factors.

2. See Page 5 for additional notes regarding cumulative losses.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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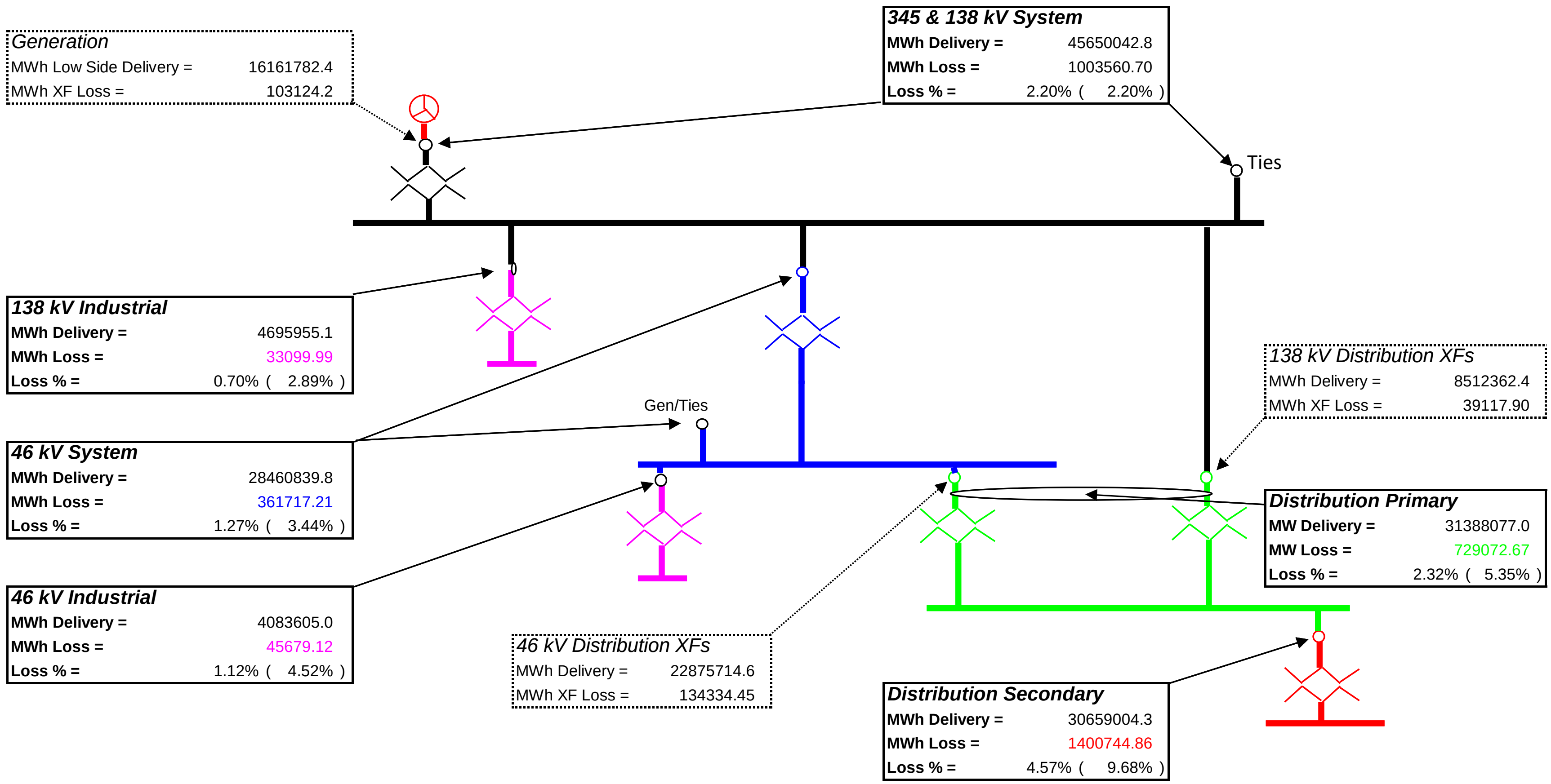
Date: May 2018

2016 SYSTEM LOSS STUDY -- ENERGY LOSSES AND DELIVERIES (TOTAL YEARLY MWh)

Combined Method (Each Component Includes Transformation to that Component)



General Notes

- Each separate component is color-coded, arrows indicate point of delivery
- Loss %'s in parantheses are the Cumulative Loss %'s.
- Loss %'s are calculated as Loss % = (MWh Loss/MWh Delivery)*100%
- Cumulative Loss %'s are calculated as one minus the product of one minus the Loss %(pu) for that component and all higher components.
- Loss % for Distribution Primary Lines (1.78%) provided by C&SI - LVD
- Generation Transformers were combined with the 345 & 138 kV system because all customers are connected at lower voltages (components).

Notes for Distribution Primary

- MW Delivery is high-side sum of 138/DST and 46/DST XFs
- MW Loss includes 138 & 46 /DST XF AND primary line loss
- Cumulative Loss % is adjusted based on the weighted average amount of load served from 138 kV and 46 kV
- First, [(22875715)*3.44%+(8512362)*2.20%]/(22875715+8512362)=3.10%
- Then, [1-(1-0.0232)*(1-0.0310)]*100%=5.35%

2016 SYSTEM LOSS STUDY -- CUMULATIVE ENERGY LOSS PERCENTAGES APPLIED TO MWh DELIVERIES

Combined Method (Each Component Includes Transformation to that Component)

Electrical System Voltage Level	MWh Deliveries (Total)[5]	Cumulative % Energy Loss[4]	MWh @ Generation	% Energy Loss
138 kV System	762,614	2.20%	779,756	2.20%
V1: >120kV[1]	4,395,256	2.89%	4,525,954	0.70%
46 kV System[1]	411,175	3.44%	425,829	1.27%
V2: 25kV - 120kV[1]	3,540,400	4.52%	3,708,058	1.12%
V3: <25kV, Primary Distribution[1&2]	8,154,860	5.35%	8,616,255	2.32%
V4: Secondary Distribution[1,2&3]	20,701,679	9.68%	22,920,134	4.57%
TOTAL	37,965,983	7.35%	40,975,986	

NOTE:

1. The cumulative loss for any level is equal to one minus the product of one minus the loss % for that level and one minus the cumulative loss % one level higher

2. The Cumulative Loss Percentages for the Distribution Primary and Secondary were adjusted to account for load served from 138 kV distribution subs. This adjustment was based on a weighted average cumulative loss % from the total MWh delivered to either 46kV/Dist. or 138/Dist.

3. The Distribution Secondary Cumulative Loss % was calculated from the MWh Gen and MWh Del remaining. Then the Energy Loss % was calculated in reverse from the cumulative.

4. All cumulative loss %s are calculated assuming the 345 kV and 138 kV Systems are combined along with the Generation Transformers (GSUs)

5. MWh Delivery figures include ROA amounts.

2016 SYSTEM LOSS STUDY -- ENERGY AND DEMAND LOSS PERCENTAGES

4-Year Summary

ENERGY LOSS %	**2013**	**2014**	**2015**	**2016**	**4-yr Avg**
345 & 138 kV System	2.34%	2.38%	2.04%	2.20%	2.24%
138 kV Industrial	0.78%	0.69%	0.69%	0.70%	0.72%
46 kV System	1.34%	1.35%	1.39%	1.27%	1.34%
46 kV Industrial	1.12%	1.11%	1.12%	1.12%	1.12%
Distribution Primary	2.37%	2.64%	2.75%	2.32%	2.52%
Distribution Secondary	4.03%	4.12%	4.35%	4.57%	4.27%

ENERGY LOSS CUMULATIVE %	**2013**	**2014**	**2015**	**2016**	**4-yr Avg**
345 & 138 kV System	2.34%	2.38%	2.04%	2.20%	2.24%
138 kV Industrial	3.11%	3.05%	2.72%	2.89%	2.94%
46 kV System	3.54%	3.70%	3.41%	3.44%	3.52%
46 kV Industrial	4.63%	4.77%	4.49%	4.52%	4.60%
Distribution Primary	5.53%	5.94%	5.68%	5.35%	5.63%
Distribution Secondary	9.35%	9.82%	9.78%	9.68%	9.66%

DEMAND LOSS %	**2013**	**2014**	**2015**	**2016**	**4-yr Avg**
345 & 138 kV System	2.55%	2.62%	2.30%	2.42%	2.47%
138 kV Industrial	0.76%	0.69%	0.68%	0.69%	0.71%
46 kV System	1.67%	1.65%	1.67%	1.52%	1.63%
46 kV Industrial	1.06%	1.06%	1.07%	1.06%	1.06%
Distribution Primary	2.98%	3.27%	3.20%	2.82%	3.07%
Distribution Secondary	4.47%	5.98%	4.22%	5.71%	5.10%

DEMAND LOSS CUMULATIVE %	**2013**	**2014**	**2015**	**2016**	**4-yr Avg**
345 & 138 kV System	2.55%	2.62%	2.30%	2.42%	2.47%
138 kV Industrial	3.29%	3.29%	2.96%	3.10%	3.16%
46 kV System	4.06%	4.23%	3.92%	3.91%	4.03%
46 kV Industrial	5.07%	5.25%	4.95%	4.93%	5.05%
Distribution Primary	6.56%	7.00%	6.54%	6.22%	6.58%
Distribution Secondary	10.73%	12.56%	10.49%	11.58%	11.34%

General Notes

- Annual Loss %'s are calculated as Loss % = [MW(h) Loss/MW(h) Delivery]*100%.
- Annual Cumulative Loss %'s are calculated as one minus the product of one minus the Loss % (pu) for that component and all higher components.
- 4-yr Average Loss %'s and Cumulative Loss %'s are the averages of the annual loss percentages.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
____	)	

EXHIBITS

OF

JOSNELLY C. APONTE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
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______________________________________	)	

EXHIBITS

OF

JOSNELLY C. APONTE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Summary
RETURN

Line No.	(a) Description	(b)	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Total Rate Base		10,715,023	10,668,437	5,226,771	2,992,421	2,326,125	117,023	6,098	46,585
2	Total Rate Revenue		4,189,566	4,164,811	1,928,645	1,056,640	1,132,640	43,302	3,584	24,755
3	Total Revenue Credits		159,038	158,942	70,536	40,824	46,101	1,426	55	96
4	Total Revenue		4,348,605	4,323,753	1,999,181	1,097,464	1,178,741	44,728	3,639	24,851
5	Expenses:									
6	Fuel and P&I Expense		1,684,726	1,667,675	649,296	389,844	619,343	8,518	675	17,051
7	Transmission Expense		439,642	435,365	182,312	101,010	149,596	2,360	88	4,277
8	Other O & M Expense		596,376	593,863	311,229	152,433	116,239	13,727	235	2,514
9	Depreciation & Amortization Expense		655,409	652,156	320,442	181,119	140,690	9,591	314	3,253
10	Other Taxes		240,354	239,648	119,651	66,623	49,768	3,364	243	706
11	Federal Income Taxes		110,944	111,391	63,080	31,284	15,625	1,086	316	(447)
12	Total Expenses		3,727,452	3,700,098	1,646,010	922,312	1,091,260	38,646	1,870	27,354
13	Net Operating Income		621,152	623,655	353,171	175,152	87,481	6,082	1,769	(2,503)
14	Other Income Adjustments		8,834	8,782	4,072	2,293	2,314	97	5	52
15	Adjusted Net Operating Income		629,986	632,437	357,243	177,445	89,795	6,179	1,774	(2,451)
16	Rate of Return on Rate Base		5.88%	5.93%	6.83%	5.93%	3.86%	5.28%	29.10%	-5.26%
17	Index of Return (Jurisdictional)			100	115	100	65	89	491	
18	Return on Rate Base @ 6.33%		678,581	675,631	331,011	189,510	147,313	7,411	386	2,950
19	Income Deficiency (Sufficiency)		48,595	43,194	(26,232)	12,064	57,518	1,232	(1,388)	5,401
20	Revenue Deficiency (Sufficiency)		65,073	57,840	(35,127)	16,155	77,020	1,650	(1,859)	7,233
21	Revenue Requirement/Total Cost of Service		4,413,677	4,381,593	1,964,054	1,113,619	1,255,762	46,378	1,781	32,084
22	Less: Revenue Credits		159,038	158,942	70,536	40,824	46,101	1,426	55	96
23	Proposed Rate Design Revenue		4,254,639	4,222,651	1,893,518	1,072,795	1,209,660	44,952	1,725	31,988
24	Production: Net Capacity Cost		1,039,771	1,030,272	435,290	249,906	343,011	1,882	183	9,499
25	Production: Capacity Related Cost Offset		621,419	614,507	235,577	140,895	234,626	3,208	202	6,912
26	Production: Non-Capacity Related Cost		1,373,164	1,357,561	523,232	312,206	512,766	8,763	594	15,603
27	Distribution: Demand Related Cost		1,029,470	1,029,557	565,438	325,567	107,167	30,650	734	(87)
28	Distribution: Customer Related Cost		190,814	190,754	133,981	44,222	12,090	449	12	61
29	Full Service MWH Sales		33,639,746	33,258,060	12,226,200	7,390,670	13,396,515	226,556	18,120	381,686
30	ROA MWH Sales		3,852,071	3,852,071	-	225,216	3,626,855	-	-	-
31	MWH Sales		37,491,817	37,110,131	12,226,200	7,615,885	17,023,370	226,556	18,120	381,686
32	Customers		1,824,591	1,824,589	1,604,424	215,234	4,183	738	10	2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1

Case No.: U-20134
Exhibit No.: A-16 (JCA-1)
Schedule: F-1
Page: 2 of 39
Witness: JCAponte
Date: May 2018

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Residential/Secondary
RETURN

Line No.	(a) Description	(b) Rate RS	(c) Rate RT	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Rate GS GEI	(h) Rate GSD GEI	(i) Total Commercial Secondary
1	Total Rate Base	5,203,993	22,778	5,226,771	1,615,541	1,222,053	51,918	102,909	2,992,421
2	Total Rate Revenue	1,920,637	8,008	1,928,645	556,102	458,132	13,119	29,287	1,056,640
3	Total Revenue Credits	70,250	286	70,536	21,402	17,610	606	1,206	40,824
4	Total Revenue	1,990,887	8,294	1,999,181	577,504	475,742	13,725	30,493	1,097,464
5	Expenses:								
6	Fuel and P&I Expense	646,507	2,789	649,296	196,032	178,899	4,932	9,980	389,844
7	Transmission Expense	181,513	799	182,312	51,067	45,714	1,380	2,848	101,010
8	Other O & M Expense	310,077	1,153	311,229	85,882	59,223	2,492	4,837	152,433
9	Depreciation & Amortization Expense	319,109	1,333	320,442	98,515	73,768	2,996	5,840	181,119
10	Other Taxes	119,153	497	119,651	35,978	27,458	1,015	2,171	66,623
11	Federal Income Taxes	62,819	261	63,080	16,674	13,742	138	730	31,284
12	Total Expenses	1,639,178	6,832	1,646,010	484,149	398,804	12,954	26,405	922,312
13	Net Operating Income	351,709	1,462	353,171	93,355	76,938	771	4,087	175,152
14	Other Income Adjustments	4,056	16	4,072	1,213	972	37	71	2,293
15	Adjusted Net Operating Income	355,765	1,478	357,243	94,569	77,910	808	4,159	177,445
16	Rate of Return on Rate Base	6.84%	6.49%	6.83%	5.85%	6.38%	1.56%	4.04%	5.93%
17	Index of Return (Jurisdictional)	115	109	115	99	108	26	68	100
18	Return on Rate Base @ 6.33%	329,568	1,443	331,011	102,312	77,392	3,288	6,517	189,510
19	Income Deficiency (Sufficiency)	(26,197)	(36)	(26,232)	7,743	(518)	2,480	2,358	12,064
20	Revenue Deficiency (Sufficiency)	(35,079)	(48)	(35,127)	10,369	(693)	3,321	3,158	16,155
21	Revenue Requirement/Total Cost of Service	1,955,807	8,246	1,964,054	587,873	475,049	17,046	33,651	1,113,619
22	Less: Revenue Credits	70,250	286	70,536	21,402	17,610	606	1,206	40,824
23	Proposed Rate Design Revenue	1,885,557	7,960	1,893,518	566,471	457,439	16,440	32,445	1,072,795
24	Production: Net Capacity Cost	433,798	1,492	435,290	124,725	115,550	3,399	6,231	249,906
25	Production: Capacity Related Cost Offset	234,553	1,024	235,577	70,496	65,144	1,807	3,448	140,895
26	Production: Non-Capacity Related Cost	520,778	2,454	523,232	157,747	142,176	3,937	8,346	312,206
27	Distribution: Demand Related Cost	562,974	2,464	565,438	177,852	126,666	6,979	14,069	325,567
28	Distribution: Customer Related Cost	133,454	526	133,981	35,652	7,902	318	350	44,222
29	Full Service MWH Sales	12,167,796	58,404	12,226,200	3,722,116	3,391,992	88,967	187,595	7,390,670
30	ROA MWH Sales	-	-	-	6,716	140,339	15,206	62,955	225,216
31	MWH Sales	12,167,796	58,404	12,226,200	3,728,832	3,532,331	104,173	250,549	7,615,885
32	Customers	1,602,178	2,246	1,604,424	192,544	20,212	1,636	841	215,234

Projected 12-Month Period Ending Dec 31, 2019
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(thousands of dollars)

Primary & Lighting
RETURN

Line No.	(a) Description	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) - Rate GU-XL	(o) Rate GU	(p) Total Lighting & Unmetered
1	Total Rate Base	296,668	408,394	344,509	1,111,265	51,331	22,788	5,544	14,742	70,884	2,326,125	5,010	93,766	12	18,234	117,023
2	Total Rate Revenue	142,017	214,613	179,943	515,187	21,951	21,746	2,051	5,523	29,609	1,132,640	1,743	33,239	2	8,318	43,302
3	Total Revenue Credits	5,084	9,949	7,544	20,613	799	607	126	260	1,118	46,101	55	1,063	0	307	1,426
4	Total Revenue	147,102	224,563	187,487	535,801	22,749	22,353	2,177	5,783	30,727	1,178,741	1,798	34,302	2	8,626	44,728
5	Expenses:															
6	Fuel and P&I Expense	61,468	151,490	105,761	261,370	9,253	12,479	1,943	2,984	12,595	619,343	483	3,887	0	4,148	8,518
7	Transmission Expense	15,593	36,383	25,604	64,961	2,559	-	432	752	3,311	149,596	158	1,274	0	928	2,360
8	Other O & M Expense	13,802	22,279	17,942	54,131	2,337	1,553	292	654	3,249	116,239	379	12,385	1	962	13,727
9	Depreciation & Amortization Expense	16,691	28,191	23,284	63,672	2,641	1,262	381	952	3,615	140,690	310	8,146	1	1,134	9,591
10	Other Taxes	7,035	6,626	7,795	24,344	1,176	765	50	329	1,648	49,768	123	2,837	0	404	3,364
11	Federal Income Taxes	4,927	(3,092)	1,076	10,202	725	954	(140)	17	956	15,625	52	875	(0)	159	1,086
12	Total Expenses	119,517	241,876	181,463	478,680	18,691	17,013	2,958	5,688	25,375	1,091,260	1,505	29,403	3	7,735	38,646
13	Net Operating Income	27,585	(17,313)	6,024	57,120	4,059	5,340	(781)	95	5,353	87,481	293	4,899	(0)	890	6,082
14	Other Income Adjustments	269	447	386	1,067	44	19	6	16	61	2,314	3	78	0	16	97
15	Adjusted Net Operating Income	27,854	(16,867)	6,410	58,187	4,103	5,359	(775)	110	5,414	89,795	296	4,977	(0)	906	6,179
16	Rate of Return on Rate Base	9.39%	-4.13%	1.86%	5.24%	7.99%	23.52%	-13.98%	0.75%	7.64%	3.86%	5.90%	5.31%	-3.69%	4.97%	5.28%
17	Index of Return (Jurisdictional)	158	(70)	31	88	135	397	(236)	13	129	65	100	90	(62)	84	89
18	Return on Rate Base @ 6.33%	18,788	25,864	21,818	70,376	3,251	1,443	351	934	4,489	147,313	317	5,938	1	1,155	7,411
19	Income Deficiency (Sufficiency)	(9,066)	42,730	15,408	12,189	(852)	(3,916)	1,126	823	(925)	57,518	21	961	1	248	1,232
20	Revenue Deficiency (Sufficiency)	(12,140)	57,219	20,632	16,322	(1,141)	(5,244)	1,508	1,102	(1,238)	77,020	29	1,287	2	333	1,650
21	Revenue Requirement/Total Cost of Service	134,961	281,781	208,119	552,123	21,609	17,109	3,685	6,885	29,489	1,255,762	1,827	35,589	4	8,958	46,378
22	Less: Revenue Credits	5,084	9,949	7,544	20,613	799	607	126	260	1,118	46,101	55	1,063	0	307	1,426
23	Proposed Rate Design Revenue	129,877	271,832	200,575	531,509	20,810	16,502	3,559	6,625	28,371	1,209,660	1,772	34,526	4	8,651	44,952
24	Production: Net Capacity Cost	39,087	75,271	55,781	156,031	5,695	-	1,029	2,261	7,856	343,011	-	-	-	1,882	1,882
25	Production: Capacity Related Cost Offset	21,484	60,064	42,405	96,777	3,207	4,210	828	1,146	4,504	234,626	192	1,484	0	1,532	3,208
26	Production: Non-Capacity Related Cost	49,075	129,717	89,041	212,387	7,695	10,827	1,599	2,192	10,232	512,766	572	4,607	1	3,584	8,763
27	Distribution: Demand Related Cost	16,808	5,743	12,246	60,849	3,794	1,346	87	981	5,312	107,167	985	28,031	3	1,631	30,650
28	Distribution: Customer Related Cost	3,422	1,037	1,101	5,465	419	119	16	45	466	12,090	22	404	0	23	449
29	Full Service MWH Sales	1,215,945	3,496,839	2,344,117	5,419,133	185,056	383,083	44,170	54,795	253,378	13,396,515	14,989	120,653	14	90,900	226,556
30	ROA MWH Sales	46,511	1,053,383	1,317,337	955,479	24,079	-	2,836	75,246	151,985	3,626,855	-	-	-	-	-
31	MWH Sales	1,262,456	4,550,222	3,661,453	6,374,612	209,135	383,083	47,006	130,040	405,363	17,023,370	14,989	120,653	14	90,900	226,556
32	Customers	1,589	47	165	1,980	189	19	3	9	182	4,183	272	-	-	466	738

Projected 12-Month Period Ending Dec 31, 2019
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4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Summary
Rate Base Summary

Line No.	(a) Description	(b)	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Net Plant									
2	Production		3,867,081	3,831,753	1,574,265	914,730	1,329,832	11,914	1,012	35,328
3	Transmission		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
4	Distribution		5,392,375	5,387,964	2,902,208	1,720,727	685,572	74,891	4,567	4,411
5	General/Common/Intangible		709,797	707,007	375,459	181,570	133,873	15,826	278	2,790
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0
7	Total Net Plant		9,969,253	9,926,724	4,851,932	2,817,027	2,149,277	102,631	5,856	42,530
8	Working Capital									
9	Total Current Assets		1,891,807	1,883,229	956,922	490,091	400,225	35,148	842	8,578
10	Total Current Liabilities		1,087,796	1,083,314	550,401	295,839	217,057	19,467	551	4,481
11	Total Working Capital		804,011	799,915	406,522	194,252	183,169	15,681	292	4,096
12	Additions to Rate Base		0	0	0	0	0	0	0	0
13	Deductions from Rate Base		58,242	58,201	31,683	18,859	6,321	1,289	50	41
14	Adjustments to Rate Base		(58,242)	(58,201)	(31,683)	(18,859)	(6,321)	(1,289)	(50)	(41)
15	Total Rate Base		10,715,023	10,668,437	5,226,771	2,992,421	2,326,125	117,023	6,098	46,585

Projected 12-Month Period Ending Dec 31, 2019
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4CP 75/0/25 Production and 12CP Transmission
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Residential/Secondary
Rate Base Summary

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	**Description**	**Rate RS**	**Rate RT**	**Total Residential**	**Rate GS**	**Rate GSD**	**Rate GS GEI**	**Rate GSD GEI**	**Commercial Secondary**
1	Net Plant								
2	Production	1,568,384	5,881	1,574,265	457,516	422,206	12,102	22,906	914,730
3	Transmission	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
4	Distribution	2,887,979	14,228	2,902,208	958,601	658,203	34,446	69,476	1,720,727
5	General/Common/Intangible	374,114	1,345	375,459	102,369	70,455	2,993	5,752	181,570
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0
7	Total Net Plant	4,830,478	21,454	4,851,932	1,518,486	1,150,864	49,542	98,135	2,817,027
8	Working Capital								
9	Total Current Assets	953,284	3,639	956,922	270,634	196,239	7,809	15,409	490,091
10	Total Current Liabilities	548,231	2,170	550,401	162,967	117,939	5,055	9,878	295,839
11	Total Working Capital	405,053	1,469	406,522	107,667	78,300	2,754	5,530	194,252
12	Additions to Rate Base	0	0	0	0	0	0	0	0
13	Deductions from Rate Base	31,537	145	31,683	10,612	7,112	378	757	18,859
14	Adjustments to Rate Base	(31,537)	(145)	(31,683)	(10,612)	(7,112)	(378)	(757)	(18,859)
15	Total Rate Base	5,203,993	22,778	5,226,771	1,615,541	1,222,053	51,918	102,909	2,992,421

Projected 12-Month Period Ending Dec 31, 2019
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(thousands of dollars)

Primary & Lighting
Rate Base Summary

Line No.	(a) Description	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) - Rate GU-XL	(o) Rate GU	(p) Total Lighting & Unmetered
1	Net Plant															
2	Production	143,201	305,696	220,874	587,504	21,086	10,525	4,079	7,833	29,034	1,329,832	441	3,548	0	7,924	11,914
3	Transmission	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
4	Distribution	116,134	42,647	75,093	379,743	24,179	8,401	728	5,185	33,461	685,572	3,763	63,164	8	7,955	74,891
5	General/Common/Intangible	16,500	24,333	20,469	63,607	2,792	1,122	324	835	3,891	133,873	418	14,337	2	1,069	15,826
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant	275,836	372,676	316,436	1,030,854	48,057	20,047	5,132	13,852	66,386	2,149,277	4,623	81,050	11	16,948	102,631
8	Working Capital															
9	Total Current Assets	48,693	75,128	62,450	186,571	8,080	4,819	944	2,369	11,171	400,225	1,034	30,966	4	3,144	35,148
10	Total Current Liabilities	26,842	39,039	33,543	102,729	4,590	1,996	525	1,422	6,371	217,057	599	17,095	2	1,771	19,467
11	Total Working Capital	21,851	36,090	28,906	83,842	3,491	2,823	419	947	4,800	183,169	435	13,871	2	1,373	15,681
12	Additions to Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Deductions from Rate Base	1,019	372	834	3,431	217	82	6	58	302	6,321	47	1,154	0	87	1,289
14	Adjustments to Rate Base	(1,019)	(372)	(834)	(3,431)	(217)	(82)	(6)	(58)	(302)	(6,321)	(47)	(1,154)	(0)	(87)	(1,289)
15	Total Rate Base	296,668	408,394	344,509	1,111,265	51,331	22,788	5,544	14,742	70,884	2,326,125	5,010	93,766	12	18,234	117,023

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Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Summary
O&M Summary

Line No.	(a) Description	(b)	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production									
2	Fuel Expense		530,311	524,562	195,987	120,722	204,141	3,446	266	5,749
3	Purchased & Interchange Power Expense		1,154,415	1,143,113	453,309	269,121	415,201	5,072	409	11,302
4	Total Fuel and P&I Expense		1,684,726	1,667,675	649,296	389,844	619,343	8,518	675	17,051
5	Fossil O&M Exp		117,668	116,472	45,384	26,991	43,414	634	49	1,196
6	Nuclear O&M Exp		0	0	0	0	0	0	0	0
7	Hydro O&M Exp		14,906	14,760	5,881	3,463	5,345	66	5	145
8	Peaker O&M Exp		38,840	38,485	15,811	9,187	13,356	120	10	355
9	Other O&M		10,151	10,059	4,133	2,401	3,491	31	3	93
10	Total Prod O&M Exp		181,565	179,776	71,208	42,043	65,607	851	67	1,789
11	Total Prod O&M Expense Including Fuel and P&I		1,866,291	1,847,451	720,504	431,887	684,950	9,369	742	18,840
12	Trans and Dist O&M									
13	Trans O&M Exp		439,642	435,365	182,312	101,010	149,596	2,360	88	4,277
14	Other O&M Adjustments		0	0	0	0	0	0	0	0
15	Distr Oper Exp		67,771	67,754	37,119	17,893	5,538	7,174	29	17
16	Distr Maint Exp		121,245	121,214	67,684	40,485	11,626	1,348	70	31
17	Total T&D Expense		628,658	624,333	287,115	159,388	166,760	10,882	188	4,325
18	Customer Related O&M									
19	Customer Accounts Exp		44,461	44,461	39,141	5,251	64	5	0	0
20	Customer Service Exp		8,693	8,634	4,397	1,525	2,672	37	3	60
21	Sales Expense		165	165	145	20	0	0	0	0
22	Total Customer Expense		53,320	53,260	43,683	6,796	2,737	42	3	60
23	Admin & General Expense		172,475	171,859	91,534	45,216	30,732	4,312	65	617
24	Total Electric O&M Expense		2,720,745	2,696,903	1,142,837	643,286	885,178	24,605	998	23,842

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Version 1
4CP 75/0/25 Production and 12CP Transmission
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Residential/Secondary
O&M Summary

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Rate RS	Rate RT	Total Residential	Rate GS	Rate GSD	Rate GS GEI	Rate GSD GEI	Commercial Secondary
1	Production								
2	Fuel Expense	195,057	930	195,987	60,951	55,156	1,474	3,142	120,722
3	Purchased & Interchange Power Expense	451,451	1,859	453,309	135,082	123,743	3,458	6,838	269,121
4	Total Fuel and P&I Expense	646,507	2,789	649,296	196,032	178,899	4,932	9,980	389,844
5	Fossil O&M Exp	45,186	197	45,384	13,555	12,416	338	681	26,991
6	Nuclear O&M Exp	0	0	0	0	0	0	0	0
7	Hydro O&M Exp	5,857	24	5,881	1,736	1,595	44	87	3,463
8	Peaker O&M Exp	15,752	59	15,811	4,595	4,241	122	230	9,187
9	Other O&M	4,117	15	4,133	1,201	1,108	32	60	2,401
10	Total Prod O&M Exp	70,913	296	71,208	21,088	19,361	536	1,059	42,043
11	Total Prod O&M Expense Including Fuel and P&I	717,420	3,084	720,504	217,120	198,260	5,468	11,039	431,887
12	Trans and Dist O&M								
13	Trans O&M Exp	181,513	799	182,312	51,067	45,714	1,380	2,848	101,010
14	Other O&M Adjustments	0	0	0	0	0	0	0	0
15	Distr Oper Exp	36,953	167	37,119	10,630	6,308	322	633	17,893
16	Distr Maint Exp	67,398	286	67,684	23,020	15,035	814	1,616	40,485
17	Total T&D Expense	285,863	1,252	287,115	84,717	67,057	2,517	5,096	159,388
18	Customer Related O&M								
19	Customer Accounts Exp	39,086	55	39,141	4,697	493	40	21	5,251
20	Customer Service Exp	4,384	13	4,397	882	584	19	41	1,525
21	Sales Expense	145	0	145	17	2	0	0	20
22	Total Customer Expense	43,616	68	43,683	5,596	1,079	59	61	6,796
23	Admin & General Expense	91,198	337	91,534	25,547	17,439	761	1,468	45,216
24	Total Electric O&M Expense	1,138,097	4,740	1,142,837	332,981	283,836	8,804	17,665	643,286

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Primary & Lighting
O&M Summary

Line No.	(a) Description	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) Rate GU-XL	(o) Rate GU	(p) Lighting & Unmetered
1	Production															
2	Fuel Expense	19,138	51,892	35,482	83,518	2,928	5,742	649	841	3,952	204,141	219	1,761	0	1,466	3,446
3	Purchased & Interchange Power Expense	42,331	99,598	70,279	177,852	6,325	6,738	1,293	2,143	8,643	415,201	264	2,126	0	2,683	5,072
4	Total Fuel and P&I Expense	61,468	151,490	105,761	261,370	9,253	12,479	1,943	2,984	12,595	619,343	483	3,887	0	4,148	8,518
5	Fossil O&M Exp	4,233	10,716	7,455	18,256	636	902	138	206	872	43,414	38	304	0	292	634
6	Nuclear O&M Exp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Hydro O&M Exp	543	1,283	906	2,293	81	84	17	28	111	5,345	4	28	0	34	66
8	Peaker O&M Exp	1,438	3,070	2,218	5,901	212	106	41	79	292	13,356	4	36	0	80	120
9	Other O&M	376	802	580	1,542	55	28	11	21	76	3,491	1	9	0	21	31
10	Total Prod O&M Exp	6,590	15,872	11,160	27,992	984	1,119	206	333	1,351	65,607	47	377	0	427	851
11	Total Prod O&M Expense Including Fuel and P&I	68,058	167,362	116,921	289,362	10,236	13,598	2,149	3,317	13,946	684,950	530	4,264	0	4,575	9,369
12	Trans and Dist O&M															
13	Trans O&M Exp	15,593	36,383	25,604	64,961	2,559	-	432	752	3,311	149,596	158	1,274	0	928	2,360
14	Other O&M Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Distr Oper Exp	1,156	84	493	3,236	215	35	2	33	285	5,538	133	6,967	1	73	7,174
16	Distr Maint Exp	1,947	245	1,148	7,058	437	88	4	79	619	11,626	81	1,080	0	187	1,348
17	Total T&D Expense	18,696	36,712	27,245	75,254	3,211	123	438	865	4,216	166,760	372	9,321	1	1,188	10,882
18	Customer Related O&M															
19	Customer Accounts Exp	24	1	3	30	3	0	0	0	3	64	3	-	-	2	5
20	Customer Service Exp	200	712	574	1,001	33	60	7	20	64	2,672	3	19	0	15	37
21	Sales Expense	0	0	0	0	0	0	0	0	0	0	0	-	-	0	0
22	Total Customer Expense	225	713	576	1,032	36	60	7	21	67	2,737	6	19	0	17	42
23	Admin & General Expense	3,885	5,365	4,566	14,813	666	250	72	188	927	30,732	112	3,940	1	259	4,312
24	Total Electric O&M Expense	90,864	210,152	149,307	380,462	14,149	14,032	2,666	4,390	19,155	885,178	1,020	17,544	2	6,038	24,605

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1

Case No.: U-20134
Exhibit No.: A-16 (JCA-1)
Schedule: F-1

Witness: JCAponte
Date: May 2018

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Summary
Allocators 1

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
	Input Allocation Schedules									
1	Energy @ Generation	100	100.000	98.916	37.175	22.472	38.528	0.689	0.052	1.084
2	Energy On-Peak @ Generation	101	100.000	98.916	35.882	23.648	38.896	0.444	0.046	1.084
3	Energy Off-Peak @ Generation	102	100.000	98.916	38.700	21.086	38.094	0.978	0.058	1.084
4	Energy On-Peak @ Generation Summer	103	100.000	98.916	36.286	23.338	38.899	0.345	0.048	1.084
5	Energy Off-Peak @ Generation Summer	104	100.000	98.916	38.473	20.562	38.904	0.912	0.066	1.084
6	Energy On-Peak @ Generation Non-Summer	105	100.000	98.916	35.662	23.817	38.894	0.497	0.045	1.084
7	Energy Off-Peak @ Generation Non-Summer	106	100.000	98.916	38.817	21.357	37.676	1.012	0.054	1.084
8	Energy Critical On-Peak @ Gen	107	100.000	98.916	35.736	25.121	37.723	0.297	0.038	1.084
9	Energy Summer Mid-Peak @ Gen	108	100.000	98.916	36.419	22.905	39.184	0.357	0.051	1.084
10	12CP Dmd @ Generation	120	100.000	99.027	41.468	22.975	34.027	0.537	0.020	0.973
11	4CP Dmd @ Generation	121	100.000	99.086	41.864	24.035	32.989	0.181	0.018	0.914
12	Class Peak @ Subtransmission	122	100.000	99.938	42.975	26.776	29.092	0.665	0.429	0.062
13	Classpeak @ Transmission	127	100.000	99.178	38.545	24.016	35.636	0.596	0.385	0.822
14	Total Rate Revenue	143	100.000	99.413	45.993	25.211	27.128	1.032	0.048	0.587
15	Billed Sales	150	100.000	98.982	32.610	20.313	45.406	0.604	0.048	1.018
16	Billed Sales Excluding Rate E1	151	100.000	98.982	32.610	20.313	45.406	0.604	0.048	1.018
17	Number Of Customers	160	100.000	100.000	87.933	11.796	0.229	0.040	0.001	0.000
18	Weighted Customer	170	100.000	99.997	60.256	27.246	12.446	0.020	0.029	0.003
	Calculated Allocation Schedules									
19	4CP Average & Excess	219	100.000	99.080	41.363	23.768	33.462	0.452	0.034	0.920
20	4CP 75/0/25	220	100.000	99.086	40.709	23.654	34.389	0.308	0.026	0.914
21	4CP 75/0/25 Exc WFR	222	100.000	99.960	41.067	23.863	34.693	0.311	0.026	0.040
22	4CP Dmd @ Gen Jurisdictional	224	100.000	100.000	42.250	24.256	33.293	0.183	0.018	-
23	12CP Demand @ Subtrans	226	100.000	100.000	45.750	25.348	28.302	0.592	0.007	-
24	Classpeak @ Primary	230	100.000	100.000	47.023	29.298	22.941	0.727	0.011	-
25	Classpeak @ Secondary	231	100.000	100.000	61.030	38.026	-	0.944	-	-
26	Classpeak for Streetlighting	233	100.000	99.324	-	-	-	99.324	-	0.676
27	Classpeak @ Single Phase	235	100.000	100.000	61.030	38.026	-	0.944	-	-
28	Billed Sales ROA	252	100.000	100.000	-	5.847	94.153	-	-	-
29	Billed Sales - Primary	253	100.000	100.000	43.147	26.877	29.175	0.800	0.001	-
30	Customers - Residential	260	100.000	100.000	100.000	-	-	-	-	-
31	Customers - Drops	261	100.000	100.000	-	100.000	-	-	-	-
32	Customers - NonPID	263	100.000	100.000	88.159	11.826	-	0.015	-	-
33	Customers - NonMunicipal	264	100.000	100.000	87.969	11.801	0.229	-	0.001	0.000
34	PIS - 138kV Distribution	301	100.000	99.178	38.545	24.016	35.636	0.596	0.385	0.822
35	PIS - 46kV Distribution	302	100.000	99.938	42.975	26.776	29.092	0.665	0.429	0.062
36	PIS - 138kV Dist Subs S&E	303	100.000	99.178	38.545	24.016	35.636	0.596	0.385	0.822
37	PIS - 46kV Dist Subs S&E	304	100.000	99.938	42.975	26.776	29.092	0.665	0.429	0.062

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(thousands of dollars)

Residential/Secondary
Allocators 1

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Alloc	Rate RS	Rate RT	Total Residential	Rate GS	Rate GSD	Rate GS GEI	Rate GSD GEI	Commercial Secondary
	Input Allocation Schedules									
1	Energy @ Generation	100	36.998	0.178	37.175	11.318	10.314	0.271	0.570	22.472
2	Energy On-Peak @ Generation	101	35.711	0.171	35.882	11.919	10.681	0.329	0.719	23.648
3	Energy Off-Peak @ Generation	102	38.514	0.186	38.700	10.609	9.881	0.202	0.395	21.086
4	Energy On-Peak @ Generation Summer	103	36.127	0.158	36.286	11.368	11.112	0.291	0.567	23.338
5	Energy Off-Peak @ Generation Summer	104	38.300	0.173	38.473	9.759	10.277	0.192	0.334	20.562
6	Energy On-Peak @ Generation Non-Summer	105	35.484	0.177	35.662	12.220	10.445	0.349	0.803	23.817
7	Energy Off-Peak @ Generation Non-Summer	106	38.625	0.192	38.817	11.047	9.677	0.207	0.426	21.357
8	Energy Critical On-Peak @ Gen	107	35.594	0.142	35.736	12.695	11.540	0.286	0.600	25.121
9	Energy Summer Mid-Peak @ Gen	108	36.256	0.162	36.419	11.046	11.009	0.292	0.559	22.905
10	12CP Dmd @ Generation	120	41.286	0.182	41.468	11.616	10.398	0.314	0.648	22.975
11	4CP Dmd @ Generation	121	41.721	0.143	41.864	11.995	11.113	0.327	0.599	24.035
12	Class Peak @ Subtransmission	122	42.779	0.197	42.975	13.710	11.216	0.604	1.246	26.776
13	Classpeak @ Transmission	127	38.369	0.177	38.545	12.297	10.060	0.541	1.118	24.016
14	Total Rate Revenue	143	45.802	0.191	45.993	13.265	10.934	0.313	0.698	25.211
15	Billed Sales	150	32.455	0.156	32.610	9.946	9.422	0.278	0.668	20.313
16	Billed Sales Excluding Rate E1	151	32.455	0.156	32.610	9.946	9.422	0.278	0.668	20.313
17	Number Of Customers	160	87.810	0.123	87.933	10.553	1.108	0.090	0.046	11.796
18	Weighted Customer	170	59.687	0.569	60.256	19.570	7.210	0.166	0.300	27.246
	Calculated Allocation Schedules									
19	4CP Average & Excess	219	41.220	0.143	41.363	11.864	10.988	0.323	0.593	23.768
20	4CP 75/0/25	220	40.557	0.152	40.709	11.831	10.918	0.313	0.592	23.654
21	4CP 75/0/25 Exc WFR	222	40.914	0.153	41.067	11.935	11.014	0.316	0.598	23.863
22	4CP Dmd @ Gen Jurisdictional	224	42.105	0.145	42.250	12.106	11.216	0.330	0.605	24.256
23	12CP Demand @ Subtrans	226	45.550	0.201	45.750	12.815	11.472	0.346	0.715	25.348
24	Classpeak @ Primary	230	46.807	0.215	47.023	15.001	12.273	0.660	1.364	29.298
25	Classpeak @ Secondary	231	60.751	0.280	61.030	19.470	15.929	0.857	1.770	38.026
26	Classpeak for Streetlighting	233	-	-	-	-	-	-	-	-
27	Classpeak @ Single Phase	235	60.751	0.280	61.030	19.470	15.929	0.857	1.770	38.026
28	Billed Sales ROA	252	-	-	-	0.174	3.643	0.395	1.634	5.847
29	Billed Sales - Primary	253	42.941	0.206	43.147	13.159	12.466	0.368	0.884	26.877
30	Customers - Residential	260	99.860	0.140	100.000	-	-	-	-	-
31	Customers - Drops	261	-	-	-	89.458	9.391	0.760	0.391	100.000
32	Customers - NonPID	263	88.035	0.123	88.159	10.580	1.111	0.090	0.046	11.826
33	Customers - NonMunicipal	264	87.846	0.123	87.969	10.557	1.108	0.090	0.046	11.801
34	PIS - 138kV Distribution	301	38.369	0.177	38.545	12.297	10.060	0.541	1.118	24.016
35	PIS - 46kV Distribution	302	42.779	0.197	42.975	13.710	11.216	0.604	1.246	26.776
36	PIS - 138kV Dist Subs S&E	303	38.369	0.177	38.545	12.297	10.060	0.541	1.118	24.016
37	PIS - 46kV Dist Subs S&E	304	42.779	0.197	42.975	13.710	11.216	0.604	1.246	26.776

Schedule F-1

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Primary & Lighting
Allocators 1

Line No.	(a) Description	Alloc	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) Rate GU-XL	(o) Rate GU	(p) Lighting & Unmetered
	Input Allocation Schedules																
1	Energy @ Generation	100	3.528	9.889	6.743	15.725	0.537	1.088	0.125	0.158	0.735	38.528	0.046	0.367	0.000	0.276	0.689
2	Energy On-Peak @ Generation	101	4.124	9.507	6.555	15.861	0.651	1.124	0.112	0.160	0.802	38.896	0.022	0.178	0.000	0.244	0.444
3	Energy Off-Peak @ Generation	102	2.826	10.340	6.964	15.564	0.402	1.046	0.140	0.155	0.656	38.094	0.073	0.590	0.000	0.315	0.978
4	Energy On-Peak @ Generation Summer	103	4.208	8.980	6.538	16.455	0.556	1.084	0.112	0.184	0.781	38.899	0.013	0.101	0.000	0.232	0.345
5	Energy Off-Peak @ Generation Summer	104	2.911	9.972	7.135	16.482	0.351	1.056	0.145	0.193	0.659	38.904	0.067	0.539	0.000	0.306	0.912
6	Energy On-Peak @ Generation Non-Summer	105	4.078	9.794	6.564	15.537	0.703	1.145	0.113	0.147	0.814	38.894	0.027	0.220	0.000	0.250	0.497
7	Energy Off-Peak @ Generation Non-Summer	106	2.782	10.530	6.876	15.091	0.429	1.041	0.137	0.136	0.655	37.676	0.077	0.616	0.000	0.319	1.012
8	Energy Critical On-Peak @ Gen	107	4.145	8.359	6.191	16.446	0.554	0.944	0.103	0.190	0.792	37.723	-	-	-	0.297	0.297
9	Energy Summer Mid-Peak @ Gen	108	4.224	9.131	6.623	16.457	0.557	1.118	0.114	0.182	0.778	39.184	0.016	0.126	0.000	0.216	0.357
10	12CP Dmd @ Generation	120	3.547	8.276	5.824	14.776	0.582	-	0.098	0.171	0.753	34.027	0.036	0.290	0.000	0.211	0.537
11	4CP Dmd @ Generation	121	3.759	7.239	5.365	15.006	0.548	-	0.099	0.217	0.756	32.989	-	-	-	0.181	0.181
12	Class Peak @ Subtransmission	122	3.868	-	7.257	14.872	0.907	0.379	-	0.506	1.304	29.092	0.057	0.460	0.000	0.147	0.665
13	Classpeak @ Transmission	127	3.469	8.565	6.509	13.339	0.813	1.179	0.139	0.454	1.170	35.636	0.051	0.413	0.000	0.132	0.596
14	Total Rate Revenue	143	3.393	5.159	4.314	12.327	0.524	0.523	0.049	0.132	0.707	27.128	0.042	0.791	0.000	0.199	1.032
15	Billed Sales	150	3.367	12.137	9.766	17.003	0.558	1.022	0.125	0.347	1.081	45.406	0.040	0.322	0.000	0.242	0.604
16	Billed Sales Excluding Rate E1	151	3.367	12.137	9.766	17.003	0.558	1.022	0.125	0.347	1.081	45.406	0.040	0.322	0.000	0.242	0.604
17	Number Of Customers	160	0.087	0.003	0.009	0.109	0.010	0.001	0.000	0.000	0.010	0.229	0.015	-	-	0.026	0.040
18	Weighted Customer	170	4.586	0.143	0.503	6.023	0.545	0.058	0.008	0.027	0.555	12.446	0.020	-	-	-	0.020
	Calculated Allocation Schedules																
19	4CP Average & Excess	219	3.718	7.218	5.338	14.872	0.542	0.714	0.098	0.214	0.748	33.462	0.030	0.241	0.000	0.181	0.452
20	4CP 75/0/25	220	3.703	7.905	5.712	15.192	0.545	0.272	0.105	0.203	0.751	34.389	0.011	0.092	0.000	0.205	0.308
21	4CP 75/0/25 Exc WFR	222	3.736	7.975	5.762	15.327	0.550	0.275	0.106	0.204	0.757	34.693	0.012	0.093	0.000	0.207	0.311
22	4CP Dmd @ Gen Jurisdictional	224	3.794	7.306	5.414	15.145	0.553	-	0.100	0.219	0.763	33.293	-	-	-	0.183	0.183
23	12CP Demand @ Subtrans	226	3.913	-	6.425	16.302	0.642	-	-	0.189	0.831	28.302	0.040	0.320	0.000	0.233	0.592
24	Classpeak @ Primary	230	4.232	-	-	16.272	0.992	0.017	-	-	1.427	22.941	0.063	0.504	0.000	0.161	0.727
25	Classpeak @ Secondary	231	-	-	-	-	-	-	-	-	-	-	0.081	0.654	0.000	0.209	0.944
26	Classpeak for Streetlighting	233	-	-	-	-	-	-	-	-	-	-	10.975	88.340	0.010	-	99.324
27	Classpeak @ Single Phase	235	-	-	-	-	-	-	-	-	-	-	0.081	0.654	0.000	0.209	0.944
28	Billed Sales ROA	252	1.207	27.346	34.198	24.804	0.625	-	0.074	1.953	3.946	94.153	-	-	-	-	-
29	Billed Sales - Primary	253	4.455	-	-	22.496	0.738	0.055	-	-	1.431	29.175	0.053	0.426	0.000	0.321	0.800
30	Customers - Residential	260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Drops	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Customers - NonPID	263	-	-	-	-	-	-	-	-	-	-	0.015	-	-	-	0.015
33	Customers - NonMunicipal	264	0.087	0.003	0.009	0.109	0.010	0.001	0.000	0.000	0.010	0.229	-	-	-	-	-
34	PIS - 138kV Distribution	301	3.469	8.565	6.509	13.339	0.813	1.179	0.139	0.454	1.170	35.636	0.051	0.413	0.000	0.132	0.596
35	PIS - 46kV Distribution	302	3.868	-	7.257	14.872	0.907	0.379	-	0.506	1.304	29.092	0.057	0.460	0.000	0.147	0.665
36	PIS - 138kV Dist Subs S&E	303	3.469	8.565	6.509	13.339	0.813	1.179	0.139	0.454	1.170	35.636	0.051	0.413	0.000	0.132	0.596
37	PIS - 46kV Dist Subs S&E	304	3.868	-	7.257	14.872	0.907	0.379	-	0.506	1.304	29.092	0.057	0.460	0.000	0.147	0.665

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1

Case No.: U-20134
Exhibit No.: A-16 (JCA-1)
Schedule: F-1

Witness: JCAponte
Date: May 2018

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Summary
Allocators 2

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
	Calculated Allocation Schedules									
1	PIS - Overhead Primary System	305	100.000	100.000	61.030	38.026	-	0.944	-	(0.000)
2	PIS - Distribution Distribution	306	100.000	99.998	57.650	34.029	5.708	2.605	0.005	0.002
3	Overhead Distribution	307	100.000	99.984	57.185	34.158	7.892	0.695	0.054	0.016
4	Underground Distribution	308	100.000	100.000	59.902	37.322	1.848	0.927	0.001	(0.000)
5	Total Dist PIS	309	100.000	99.930	54.398	32.380	10.853	2.213	0.086	0.070
6	Distribution Services	310	100.000	100.000	66.547	33.453	-	-	-	-
7	Streetlighting Equipment	311	100.000	99.908	-	-	-	99.908	-	0.092
8	Line Equipment	312	100.000	100.000	59.260	36.923	2.899	0.917	0.001	-
9	Meters	313	100.000	99.997	60.256	27.246	12.446	0.020	0.029	0.003
10	PIS - System Power Control	314	100.000	199.116	81.521	50.792	64.728	1.261	0.814	(99.116)
11	PIS - General	315	100.000	99.607	52.897	25.581	18.861	2.230	0.039	0.393
12	Total PIS	316	100.000	99.582	49.082	28.473	20.475	1.493	0.059	0.418
13	Distribution Depreciation	317	100.000	99.954	55.375	33.206	7.549	3.732	0.092	0.046
14	CWIP	330	100.000	99.411	46.096	25.962	26.195	1.098	0.060	0.589
15	Working Capital	340	100.000	99.491	50.562	24.160	22.782	1.950	0.036	0.509
16	Rate Base	390	100.000	99.565	48.780	27.927	21.709	1.092	0.057	0.435
17	Operations - Distribution excl Sup & Eng	400	100.000	99.980	55.313	26.396	7.204	11.039	0.027	0.020
18	Maintenance - Distribution excl Sup & Eng	401	100.000	99.988	56.460	33.728	8.623	1.133	0.043	0.012
19	Operations - 138kV Distribution excl Sup & Eng	402	100.000	99.086	41.864	24.035	32.989	0.181	0.018	0.914
20	Maintenance - 138kV Distribution excl Sup & Eng	403	100.000	99.230	38.780	24.031	35.488	0.570	0.362	0.770
21	Operations - 46kV Distribution excl Sup & Eng	404	100.000	99.938	42.975	26.776	29.092	0.665	0.429	0.062
22	Maintenance - 46kV Distribution excl Sup & Eng	405	100.000	99.938	42.975	26.776	29.092	0.665	0.429	0.062
23	HV Distribution O&M exp.	406	100.000	99.746	41.966	26.051	30.701	0.627	0.400	0.254
24	Distribution O&M, excl. HV Dist	407	100.000	99.985	56.068	31.087	8.084	4.711	0.037	0.015
25	Customer Accounting	408	100.000	100.000	88.033	11.810	0.145	0.012	0.000	0.000
26	Customer Accounts & Service	409	100.000	99.888	81.908	12.748	5.148	0.079	0.006	0.112
27	Distribution O&M	410	100.000	99.975	55.447	30.885	9.081	4.509	0.053	0.025
28	Customer & Sales O&M	411	100.000	99.888	81.926	12.745	5.132	0.079	0.006	0.112
29	Administrative and General O&M	412	100.000	99.642	53.071	26.216	17.818	2.500	0.038	0.358
30	Jurisdictional Distribution O&M	414	100.000	100.000	55.461	30.893	9.083	4.510	0.053	-
31	O&M Excluding Adjustments	438	100.000	99.124	42.005	23.644	32.534	0.904	0.037	0.876
32	Pre Tax NOI	439	100.000	100.403	56.857	28.198	14.084	0.979	0.285	(0.403)
33	R&PP Tax	440	100.000	99.604	48.832	28.342	20.920	1.440	0.070	0.396
34	Depreciation & Amortization Expense	442	100.000	99.504	48.892	27.635	21.466	1.463	0.048	0.496
35	Non PSCR O&M Expense	443	100.000	99.579	52.187	25.560	19.491	2.302	0.039	0.421
36	Distribution Depreciation Expense	444	100.000	99.949	56.723	33.276	7.396	2.477	0.078	0.051
37	Gen/Comm/Int Depreciation Expense	445	100.000	99.607	52.897	25.581	18.861	2.230	0.039	0.393
38	Production Labor	500	100.000	99.086	40.709	23.654	34.389	0.308	0.026	0.914
39	Total Labor	502	100.000	99.607	52.897	25.581	18.861	2.230	0.039	0.393
40	50% O&M, 50% Net Plant	600	100.000	99.477	47.240	27.268	23.912	1.003	0.054	0.523
41	50/50 PIS & Labor	601	100.000	99.594	50.989	27.027	19.668	1.862	0.049	0.406

Projected 12-Month Period Ending Dec 31, 2019
Version 1
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(thousands of dollars)

Residential/Secondary
Allocators 2

Line No.	(a) Description	Alloc	(b) Rate RS	(c) Rate RT	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Rate GS GEI	(h) Rate GSD GEI	(i) Commercial Secondary
	Calculated Allocation Schedules									
1	PIS - Overhead Primary System	305	60.751	0.280	61.030	19.470	15.929	0.857	1.770	38.026
2	PIS - Distribution Distribution	306	57.386	0.265	57.650	19.473	12.565	0.667	1.325	34.029
3	Overhead Distribution	307	56.962	0.223	57.185	19.841	12.311	0.678	1.328	34.158
4	Underground Distribution	308	59.627	0.274	59.902	19.110	15.634	0.841	1.737	37.322
5	Total Dist PIS	309	54.148	0.250	54.398	18.220	12.211	0.649	1.300	32.380
6	Distribution Services	310	66.454	0.093	66.547	29.927	3.142	0.254	0.131	33.453
7	Streetlighting Equipment	311	-	-	-	-	-	-	-	-
8	Line Equipment	312	58.989	0.271	59.260	18.906	15.467	0.832	1.718	36.923
9	Meters	313	59.687	0.569	60.256	19.570	7.210	0.166	0.300	27.246
10	PIS - System Power Control	314	81.147	0.373	81.521	26.007	21.276	1.145	2.364	50.792
11	PIS - General	315	52.707	0.189	52.897	14.422	9.926	0.422	0.810	25.581
12	Total PIS	316	48.874	0.207	49.082	15.464	11.519	0.502	0.988	28.473
13	Distribution Depreciation	317	55.152	0.223	55.375	19.005	12.212	0.669	1.320	33.206
14	CWIP	330	45.914	0.181	46.096	13.736	11.000	0.416	0.809	25.962
15	Working Capital	340	50.379	0.183	50.562	13.391	9.739	0.343	0.688	24.160
16	Rate Base	390	48.567	0.213	48.780	15.077	11.405	0.485	0.960	27.927
17	Operations - Distribution excl Sup & Eng	400	55.064	0.248	55.313	15.782	9.222	0.470	0.922	26.396
18	Maintenance - Distribution excl Sup & Eng	401	56.222	0.238	56.460	19.243	12.470	0.676	1.339	33.728
19	Operations - 138kV Distribution excl Sup & Eng	402	41.721	0.143	41.864	11.995	11.113	0.327	0.599	24.035
20	Maintenance - 138kV Distribution excl Sup & Eng	403	38.606	0.175	38.780	12.285	10.133	0.528	1.085	24.031
21	Operations - 46kV Distribution excl Sup & Eng	404	42.779	0.197	42.975	13.710	11.216	0.604	1.246	26.776
22	Maintenance - 46kV Distribution excl Sup & Eng	405	42.779	0.197	42.975	13.710	11.216	0.604	1.246	26.776
23	HV Distribution O&M exp.	406	41.776	0.190	41.966	13.324	10.962	0.577	1.188	26.051
24	Distribution O&M, excl. HV Dist	407	55.826	0.242	56.068	18.000	11.296	0.602	1.188	31.087
25	Customer Accounting	408	87.910	0.123	88.033	10.565	1.109	0.090	0.046	11.810
26	Customer Accounts & Service	409	81.781	0.127	81.908	10.496	2.027	0.111	0.115	12.748
27	Distribution O&M	410	55.207	0.240	55.447	17.803	11.292	0.601	1.189	30.885
28	Customer & Sales O&M	411	81.799	0.127	81.926	10.496	2.024	0.110	0.115	12.745
29	Administrative and General O&M	412	52.876	0.195	53.071	14.812	10.111	0.441	0.851	26.216
30	Jurisdictional Distribution O&M	414	55.221	0.240	55.461	17.807	11.295	0.601	1.190	30.893
31	O&M Excluding Adjustments	438	41.830	0.174	42.005	12.239	10.432	0.324	0.649	23.644
32	Pre Tax NOI	439	56.622	0.235	56.857	15.029	12.386	0.124	0.658	28.198
33	R&PP Tax	440	48.626	0.206	48.832	15.338	11.518	0.500	0.986	28.342
34	Depreciation & Amortization Expense	442	48.689	0.203	48.892	15.031	11.255	0.457	0.891	27.635
35	Non PSCR O&M Expense	443	51.993	0.193	52.187	14.401	9.930	0.418	0.811	25.560
36	Distribution Depreciation Expense	444	56.453	0.270	56.723	19.089	12.262	0.644	1.281	33.276
37	Gen/Comm/Int Depreciation Expense	445	52.707	0.189	52.897	14.422	9.926	0.422	0.810	25.581
38	Production Labor	500	40.557	0.152	40.709	11.831	10.918	0.313	0.592	23.654
39	Total Labor	502	52.707	0.189	52.897	14.422	9.926	0.422	0.810	25.581
40	50% O&M, 50% Net Plant	600	47.034	0.206	47.240	14.590	11.306	0.460	0.913	27.268
41	50/50 PIS & Labor	601	50.791	0.198	50.989	14.943	10.722	0.462	0.899	27.027

Schedule F-1

Projected 12-Month Period Ending Dec 31, 2019
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(thousands of dollars)

Primary & Lighting
Allocators 2

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description	Alloc	Rate GP	Rate GPD Vlt 1	Rate GPD Vlt 2	Rate GPD Vlt 3	Rate GP GEI	Rate EIP	Rate GPD GEI Vlt 1	Rate GPD GEI Vlt 2	Rate GPD GEI Vlt 3	Total Primary	Rate GML	Rate GUL	Rate GU-XL	Rate GU	Lighting & Unmetered
	Calculated Allocation Schedules																
1	PIS - Overhead Primary System	305	-	-	-	-	-	-	-	-	-	-	0.081	0.654	0.000	0.209	0.944
2	PIS - Distribution Distribution	306	1.257	0.013	0.048	3.794	0.247	0.009	0.001	0.003	0.335	5.708	0.088	2.366	0.000	0.152	2.605
3	Overhead Distribution	307	1.257	0.091	0.871	4.834	0.295	0.058	0.001	0.061	0.424	7.892	0.060	0.481	0.000	0.154	0.695
4	Underground Distribution	308	0.341	-	-	1.311	0.080	0.001	-	-	0.115	1.848	0.080	0.641	0.000	0.205	0.927
5	Total Dist PIS	309	1.749	0.638	1.432	5.892	0.372	0.141	0.011	0.099	0.519	10.853	0.081	1.982	0.000	0.150	2.213
6	Distribution Services	310	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Streetlighting Equipment	311	-	-	-	-	-	-	-	-	-	-	1.497	98.397	0.014	-	99.908
8	Line Equipment	312	0.535	-	-	2.056	0.125	0.002	-	-	0.180	2.899	0.079	0.635	0.000	0.203	0.917
9	Meters	313	4.586	0.143	0.503	6.023	0.545	0.058	0.008	0.027	0.555	12.446	0.020	-	-	-	0.020
10	PIS - System Power Control	314	7.338	8.565	13.766	28.210	1.720	1.557	0.139	0.959	2.474	64.728	0.108	0.873	0.000	0.279	1.261
11	PIS - General	315	2.325	3.428	2.884	8.961	0.393	0.158	0.046	0.118	0.548	18.861	0.059	2.020	0.000	0.151	2.230
12	Total PIS	316	2.540	3.637	3.181	9.686	0.440	0.192	0.050	0.140	0.609	20.475	0.053	1.270	0.000	0.171	1.493
13	Distribution Depreciation	317	1.017	0.339	1.557	3.836	0.235	0.115	0.006	0.108	0.337	7.549	0.102	3.475	0.000	0.153	3.732
14	CWIP	330	3.046	5.058	4.364	12.076	0.498	0.216	0.068	0.179	0.690	26.195	0.037	0.880	0.000	0.180	1.098
15	Working Capital	340	2.718	4.489	3.595	10.428	0.434	0.351	0.052	0.118	0.597	22.782	0.054	1.725	0.000	0.171	1.950
16	Rate Base	390	2.769	3.811	3.215	10.371	0.479	0.213	0.052	0.138	0.662	21.709	0.047	0.875	0.000	0.170	1.092
17	Operations - Distribution excl Sup & Eng	400	1.607	0.101	0.438	4.314	0.292	0.038	0.003	0.029	0.383	7.204	0.203	10.729	0.002	0.105	11.039
18	Maintenance - Distribution excl Sup & Eng	401	1.512	0.074	0.681	5.444	0.338	0.047	0.001	0.047	0.478	8.623	0.067	0.911	0.000	0.155	1.133
19	Operations - 138kV Distribution excl Sup & Eng	402	3.759	7.239	5.365	15.006	0.548	0.000	0.099	0.217	0.756	32.989	0.000	0.000	0.000	0.181	0.181
20	Maintenance - 138kV Distribution excl Sup & Eng	403	3.490	8.485	6.439	13.453	0.797	1.104	0.137	0.439	1.144	35.488	0.048	0.387	0.000	0.135	0.570
21	Operations - 46kV Distribution excl Sup & Eng	404	3.868	-	7.257	14.872	0.907	0.379	-	0.506	1.304	29.092	0.057	0.460	0.000	0.147	0.665
22	Maintenance - 46kV Distribution excl Sup & Eng	405	3.868	-	7.257	14.872	0.907	0.379	-	0.506	1.304	29.092	0.057	0.460	0.000	0.147	0.665
23	HV Distribution O&M exp.	406	3.777	2.201	7.007	14.547	0.870	0.535	0.035	0.481	1.250	30.701	0.053	0.428	0.000	0.146	0.627
24	Distribution O&M, excl. HV Dist	407	1.544	0.077	0.584	5.030	0.321	0.043	0.002	0.040	0.443	8.084	0.116	4.457	0.001	0.137	4.711
25	Customer Accounting	408	0.055	0.002	0.006	0.069	0.007	0.001	0.000	0.000	0.006	0.145	0.008	-	-	0.004	0.012
26	Customer Accounts & Service	409	0.422	1.342	1.084	1.941	0.068	0.113	0.014	0.039	0.125	5.148	0.012	0.036	0.000	0.031	0.079
27	Distribution O&M	410	1.642	0.174	0.868	5.446	0.345	0.065	0.003	0.060	0.479	9.081	0.113	4.258	0.001	0.138	4.509
28	Customer & Sales O&M	411	0.421	1.338	1.080	1.935	0.067	0.113	0.014	0.038	0.125	5.132	0.012	0.035	0.000	0.031	0.079
29	Administrative and General O&M	412	2.253	3.111	2.647	8.589	0.386	0.145	0.042	0.109	0.537	17.818	0.065	2.284	0.000	0.150	2.500
30	Jurisdictional Distribution O&M	414	1.642	0.174	0.868	5.447	0.345	0.065	0.003	0.060	0.479	9.083	0.113	4.259	0.001	0.138	4.510
31	O&M Excluding Adjustments	438	3.340	7.724	5.488	13.984	0.520	0.516	0.098	0.161	0.704	32.534	0.038	0.645	0.000	0.222	0.904
32	Pre Tax NOI	439	4.441	(2.787)	0.970	9.196	0.653	0.860	(0.126)	0.015	0.862	14.084	0.047	0.789	(0.000)	0.143	0.979
33	R&PP Tax	440	2.628	3.359	3.404	10.062	0.459	0.171	0.045	0.154	0.638	20.920	0.052	1.217	0.000	0.171	1.440
34	Depreciation & Amortization Expense	442	2.547	4.301	3.553	9.715	0.403	0.192	0.058	0.145	0.552	21.466	0.047	1.243	0.000	0.173	1.463
35	Non PSCR O&M Expense	443	2.314	3.736	3.008	9.077	0.392	0.260	0.049	0.110	0.545	19.491	0.064	2.076	0.000	0.161	2.302
36	Distribution Depreciation Expense	444	1.282	0.444	1.309	3.590	0.239	0.114	0.008	0.090	0.318	7.396	0.084	2.247	0.000	0.146	2.477
37	Gen/Comm/Int Depreciation Expense	445	2.325	3.428	2.884	8.961	0.393	0.158	0.046	0.118	0.548	18.861	0.059	2.020	0.000	0.151	2.230
38	Production Labor	500	3.703	7.905	5.712	15.192	0.545	0.272	0.105	0.203	0.751	34.389	0.011	0.092	0.000	0.205	0.308
39	Total Labor	502	2.325	3.428	2.884	8.961	0.393	0.158	0.046	0.118	0.548	18.861	0.059	2.020	0.000	0.151	2.230
40	50% O&M, 50% Net Plant	600	2.890	4.593	3.670	11.121	0.490	0.269	0.061	0.144	0.674	23.912	0.044	0.777	0.000	0.181	1.003
41	50/50 PIS & Labor	601	2.432	3.533	3.032	9.323	0.416	0.175	0.048	0.129	0.579	19.668	0.056	1.645	0.000	0.161	1.862

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Net Plant

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Plant in Service									
2	Production		5,808,691	5,755,625	2,364,682	1,374,004	1,997,523	17,895	1,520	53,066
3	Transmission		0	0	0	0	0	0	0	0
4	Distribution		8,171,969	8,166,274	4,445,390	2,646,081	886,880	180,868	7,054	5,695
5	General/Common/Intangible		1,359,164	1,353,821	718,953	347,682	256,349	30,306	532	5,343
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0
7	Total Plant in Service		15,339,824	15,275,720	7,529,025	4,367,767	3,140,753	229,069	9,106	64,104
8	Depreciation Reserve									
9	Production		2,211,253	2,191,052	900,188	523,056	760,417	6,812	579	20,201
10	Transmission		0	0	0	0	0	0	0	0
11	Distribution		2,901,832	2,900,491	1,606,881	963,583	219,059	108,285	2,683	1,341
12	General/Common/Intangible		749,513	746,567	396,468	191,730	141,364	16,712	293	2,946
13	Total Depreciation Reserve		5,862,598	5,838,110	2,903,536	1,678,369	1,120,841	131,809	3,555	24,488
14	Construction Work In Progress (CWIP)									
15	Production		267,902	265,455	109,061	63,370	92,128	825	70	2,447
16	Transmission		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
17	Distribution		118,703	118,676	62,336	37,380	16,491	2,286	182	27
18	General/Common/Intangible		100,146	99,752	52,974	25,618	18,888	2,233	39	394
19	Total CWIP		486,751	483,882	224,371	126,369	127,506	5,345	291	2,869
20	Future Use									
21	Production	220	1,741	1,725	709	412	599	5	0	16
22	Distribution	127	3,535	3,506	1,363	849	1,260	21	14	29
23	Common/General	231	0	0	0	0	-	0	-	-
24	PHFFU Depreciation Reserve	127	0	0	0	0	0	0	0	0
25	Total Future Use		5,277	5,232	2,072	1,261	1,859	26	14	45
26	Net Plant		9,969,253	9,926,724	4,851,932	2,817,027	2,149,277	102,631	5,856	42,530

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PIS Summary

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production									
2	Production Plant in Service		5,808,691	5,755,625	2,364,682	1,374,004	1,997,523	17,895	1,520	53,066
3	Generation Step Ups		0	0	0	0	0	0	0	0
4	Total Production		5,808,691	5,755,625	2,364,682	1,374,004	1,997,523	17,895	1,520	53,066
5	Transmission									
6	Bulk Power Transm		0	0	0	0	0	0	0	0
7	Transm; Subtrans		0	0	0	0	0	0	0	0
8	Subtransmission		0	0	0	0	0	0	0	0
9	Total Transmission		0	0	0	0	0	0	0	0
10	Distribution									
11	Stations and Equipment		2,400,539	2,395,646	1,179,831	734,730	458,353	18,201	4,531	4,893
12	Overhead System		3,489,456	3,488,789	1,921,922	1,197,470	337,379	29,728	2,289	667
13	Underground System		784,489	784,481	467,641	291,368	18,174	7,233	65	8
14	Meters and Svc Drops		1,378,944	1,378,926	875,997	422,513	72,975	7,272	169	18
15	St Lgts and OPL		118,542	118,433	-	-	-	118,433	-	109
16	Total Distribution		8,171,969	8,166,274	4,445,390	2,646,081	886,880	180,868	7,054	5,695
17	General/Common/Intangible									
18	Total Gen/Comm/Int Plant		1,359,164	1,353,821	718,953	347,682	256,349	30,306	532	5,343
19	Plant Purchased/Sold		0	0	0	0	0	0	0	0
20	Total Plant in Service		15,339,824	15,275,720	7,529,025	4,367,767	3,140,753	229,069	9,106	64,104

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Plant In Service (production & tran)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production Plant									
2	Fossil	220	4,262,479	4,223,538	1,735,229	1,008,259	1,465,804	13,132	1,115	38,941
3	Nuclear	220	0	0	0	0	0	0	0	0
4	Total Hydro	220	546,303	541,312	222,397	129,224	187,866	1,683	143	4,991
5	Other Production/Combustion Turbine	220	999,909	990,774	407,057	236,521	343,854	3,080	262	9,135
6	7 Classics	220	0	0	0	0	0	0	0	0
7	Jackson Gas Plant	220	0	0	0	0	0	0	0	0
6	Distribution GSUs	220	0	0	0	0	0	0	0	0
7	Total Production		5,808,691	5,755,625	2,364,682	1,374,004	1,997,523	17,895	1,520	53,066
8	Transmission Plant									
9	Transmission Direct	228	0	0	0	0	0	0	0	0
10	Subtransmission	228	0	0	0	0	0	0	0	0
11	Transmission	127	0	0	0	0	0	0	0	0
12	Total		0	0	0	0	0	0	0	0

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Plant In Service (distribution)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Plant									
2	345/138kV Substations/Overheads (METC) Land & ROW	127	89,200	88,467	34,382	21,422	31,788	532	343	733
3	345/138kV Substations/Overheads Land & ROW	127	26,832	26,611	10,342	6,444	9,562	160	103	220
4	46/23kV Substations/Overheads Land & ROW	124	48,795	48,764	20,970	13,065	14,196	324	209	30
5	Distribution Substation Land & ROW	230	7,812	7,812	3,673	2,289	1,792	57	1	-
6	138kV Substations/Overheads (Assignable) Land & ROW	DIR	0	-	-	-	-	-	-	-
7	46kV Substations/Overheads (Assignable) Land & ROW	DIR	0	-	-	-	-	-	-	-
8	Overhead Lines Land & ROW	307	25,419	25,415	14,536	8,683	2,006	177	14	4
9	Total		198,057	197,070	83,904	51,903	59,343	1,250	670	988
10	Distribution Substations & Equipment								-	-
11	138kV Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
12	46kV Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
13	138kV HV Subtran/Dist Substations	127	437,686	434,090	168,707	105,115	155,975	2,610	1,684	3,596
14	138kV HV Subtran/Dist Substations	127	0	0	0	0	0	0	0	0
15	46kV Subtran/Dist Substations	124	496,363	496,054	213,314	132,907	144,404	3,300	2,130	309
16	Distribution Substations	230	308,662	308,662	145,141	90,431	70,810	2,245	33	-
17	Total		1,242,711	1,238,806	527,162	328,453	371,189	8,154	3,848	3,905
18	Distribution Overhead System									
19	138kV HV Subtran/Dist Overhead Lines	127	45,400	45,027	17,499	10,903	16,179	271	175	373
20	138kV HV Subtran/Dist Overhead Lines	121	0	0	0	0	0	0	0	0
21	46kV Subtran Overheads & Transformer Platforms	122	472,514	472,220	203,065	126,521	137,465	3,141	2,027	294
22	Transformer Platforms	231	3,921	3,921	2,393	1,491	-	37	-	-
23	Three Phase Primary	230	800,898	800,898	376,604	234,647	183,735	5,825	87	-
24	Single Phase Primary	235	655,281	655,281	399,921	249,174	-	6,186	-	-
25	Single Phase Secondary	231	1,511,442	1,511,442	922,440	574,734	-	14,268	-	-
26	Total		3,489,456	3,488,789	1,921,922	1,197,470	337,379	29,728	2,289	667
27	Distribution Underground System									-
28	Three Phase Primary	230	62,124	62,124	29,212	18,201	14,252	452	7	-
29	Single Phase Primary	235	570,877	570,877	348,409	217,079	-	5,389	-	-
30	Single Phase Secondary	231	138,006	138,006	84,226	52,478	-	1,303	-	-
31	46kV Subtran/Distribution Underground Lines	122	13,482	13,473	5,794	3,610	3,922	90	58	8
32	Total		784,489	784,481	467,641	291,368	18,174	7,233	65	8
33	Distribution Line Equipment									-
34	Primary	230	121,272	121,272	57,025	35,530	27,821	882	13	-
35	Secondary	231	838,498	838,498	511,739	318,844	-	7,916	-	-
36	Total		959,770	959,770	568,765	354,374	27,821	8,798	13	-
37	Distribution Services									
38	Residential Overhead & Burial Services	260	522,704	522,704	522,704	-	-	-	-	-
39	C&I Overhead & Burial Services	261	262,763	262,763	-	262,763	-	-	-	-
40	Total		785,467	785,467	522,704	262,763	-	-	-	-

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Plant In Service (distribution & general)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Metering Equipment									
2	Metering Equipment (Mass)	170	586,322	586,304	353,293	159,750	72,975	118	169	18
3	Total		586,322	586,304	353,293	159,750	72,975	118	169	18
4	Distribution Installations on Customer Premises									
5	Installations on Premises L4 (Assignable)	DIR	7,155	7,155	-	-	-	7,155	-	-
6	Total		7,155	7,155	-	-	-	7,155	-	-
7	Distribution Streetlighting Equipment									
8	Luminaires/Suspensions/Poles/Transformers	DIR	102,376	102,376	-	-	-	102,376	-	-
9	Underground Cable & Conduits	233	9,154	9,092	-	-	-	9,092	-	62
10	Photoelectric Switches	233	7,012	6,965	-	-	-	6,965	-	47
11	Total		118,542	118,433	-	-	-	118,433	-	109
12	Total Distribution Plant in Service		8,171,969	8,166,274	4,445,390	2,646,081	886,880	180,868	7,054	5,695
13	Test Year Distribution PIS	309	8,171,969	8,166,274	4,445,390	2,646,081	886,880	180,868	7,054	5,695
14	Electric Plant Purchased & Sold	220	0	0	0	0	0	0	0	0
15	General, Common & Intangible									
16	General: Production Related	220	0	0	0	0	0	0	0	0
17	General: Merchant Control	226	0	0	0	0	0	0	0	-
18	General: Power Control Center 138kV	301	0	0	0	0	0	0	0	0
19	General: Power Control Center 46kV	302	0	0	0	0	0	0	0	0
20	General: Functionalized	502	271,455	270,388	143,591	69,440	51,199	6,053	106	1,067
21	General: Reallocated from/(to) Gas	DIR	0	-	-	-	-	-	-	-
22	Common: Functionalized	502	366,714	365,272	193,980	93,807	69,165	8,177	144	1,442
23	Franchises & Consents - Generation	220	0	0	0	0	0	0	0	0
24	Intangible PIS	502	720,995	718,161	381,383	184,435	135,985	16,076	282	2,834
25	Total General, Common & Intangible		1,359,164	1,353,821	718,953	347,682	256,349	30,306	532	5,343

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Depreciation Reserve Summary

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production									
2	Production Depreciation Reserve		2,211,253	2,191,052	900,188	523,056	760,417	6,812	579	20,201
3	Generation Step Ups		0	0	0	0	0	0	0	0
4	Total Production		2,211,253	2,191,052	900,188	523,056	760,417	6,812	579	20,201
5	Transmission									
6	Bulk Power Transm	225	-	-	-	-	-	-	-	-
7	Transm; Subtrans	122	0	0	0	0	0	0	0	0
8	Subtransmission	230	0	0	0	0	0	0	0	0
9	Total Transmission		0	0	0	0	0	0	0	0
10	Distribution									
11	Stations and Equipment		693,843	692,884	359,931	224,086	102,320	5,545	1,002	959
12	Overhead System		1,356,006	1,355,887	810,531	505,009	27,417	12,537	393	119
13	Underground System		301,641	301,455	130,061	81,036	87,062	2,012	1,283	186
14	Meters and Svc Drops		467,880	467,879	306,357	153,453	2,260	5,803	5	1
15	St Lgts and OPL		82,463	82,387	-	-	-	82,387	-	76
16	Total Distribution		2,901,832	2,900,491	1,606,881	963,583	219,059	108,285	2,683	1,341
17	General/Common/Intangible									
18	Total Gen/Comm/Int		749,513	746,567	396,468	191,730	141,364	16,712	293	2,946
19	Total Depreciation Reserve		5,862,598	5,838,110	2,903,536	1,678,369	1,120,841	131,809	3,555	24,488

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1

Case No.: U-20134
Exhibit No.: A-16 (JCA-1)
Schedule: F-1

Witness: JCAponte
Date: May 2018

Projected 12-Month Period Ending Dec 31, 2019
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(thousands of dollars)

Depreciation Reserve (prod & tran)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production									
2	Fossil	220	1,458,224	1,444,902	593,634	344,932	501,462	4,492	382	13,322
3	Nuclear	220	0	0	0	0	0	0	0	0
4	Hydro	220	306,248	303,450	124,672	72,441	105,314	943	80	2,798
5	Other Production/Combustion Turbine	220	446,781	442,699	181,882	105,683	153,641	1,376	117	4,082
6	Jackson Gas Plant	220	0	0	0	0	0	0	0	0
7	7 Classics	220	0	0	0	0	0	0	0	0
6	Distribution GSUs	220	0	0	0	0	0	0	0	0
7	Total Production		2,211,253	2,191,052	900,188	523,056	760,417	6,812	579	20,201
8	Transmission									
9	Transmission Direct	DIR	0	-	-	-	-	-	-	-
10	Total Subtransmission	228	0	0	0	0	0	0	0	0
11	Total Transmission	123	0	0	0	0	0	0	0	0
12	Total		0	0	0	0	0	0	0	0

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Depreciation Reserve (distribution)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Depreciation Reserve									
2	Distribution Land & Right of Way		-	-	-	-	-	-	-	-
3	345/138kV Substations/Overheads (METC)	127	8,749	8,677	3,372	2,101	3,118	52	34	72
4	345/138kV Substations/Overheads	127	2,295	2,276	885	551	818	14	9	19
5	46/23kV Substations/Overheads	124	9,109	9,103	3,915	2,439	2,650	61	39	6
6	Substations/Overheads (Assignable)	DIR	0	-	-	-	-	-	-	-
7	Overhead Lines Land & ROW	307	11,700	11,698	6,691	3,996	923	81	6	2
8	Total		31,852	31,754	14,862	9,088	7,509	208	88	98
9	Distribution Substations & Equipment									
10	Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
11	138kV HV Subtran/Dist Substations	127	95,282	94,500	36,727	22,883	33,955	568	367	783
12	46kV Subtran /Dist Substations	122	124,811	124,733	53,638	33,420	36,310	830	536	78
13	Distribution Substations	230	58,555	58,555	27,534	17,155	13,433	426	6	-
14	Total		278,648	277,788	117,899	73,458	83,699	1,824	909	861
15	Distribution Overhead System		-	-	-	-	-	-	-	-
16	138kV HV Subtran/Dist Overhead Lines	127	8,116	8,049	3,128	1,949	2,892	48	31	67
17	46kV Subtran Overheads & Transformer Platforms	122	84,300	84,248	36,228	22,572	24,525	560	362	52
18	Single Phase Primary & Secondary	305	1,263,590	1,263,590	771,174	480,487	-	11,928	-	-
19	Total		1,356,006	1,355,887	810,531	505,009	27,417	12,537	393	119
20	Distribution Underground System									
21	Distribution UG System	308	2,541	2,541	1,522	948	47	24	0	-
22	46kV Subtran/Distribution UG Lines	122	299,100	298,914	128,539	80,088	87,015	1,988	1,283	186
23	Total		301,641	301,455	130,061	81,036	87,062	2,012	1,283	186
24	Distribution Line Equipment									
25	Capacitors/Regulators/Transformers	312	383,342	383,342	227,170	141,540	11,112	3,514	5	-
26	Total		383,342	383,342	227,170	141,540	11,112	3,514	5	-
27	Distribution Services									
28	C&I and Residential Services	310	443,919	443,919	295,415	148,505	-	-	-	-
29	Total		443,919	443,919	295,415	148,505	-	-	-	-

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Depreciation Reserve (dist & general)

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	Distribution Metering Equipment									
2	Metering Equipment (Mass)	170	18,161	18,160	10,943	4,948	2,260	4	5	1
3	Total		18,161	18,160	10,943	4,948	2,260	4	5	1
4	Distribution Installations on Customer Premises									
5	Installations on Premises L4 (Assignable)	DIR	5,800	5,800	-	-	-	5,800	-	-
6	Total		5,800	5,800	-	-	-	5,800	-	-
7	Distribution Streetlighting Equipment									
8	Streetlighting Equipment Depreciation Reserve	311	82,463	82,387	-	-	-	82,387	-	76
9	Total		82,463	82,387	-	-	-	82,387	-	76
10	Distribution Depreciation Reserve		2,901,832	2,900,491	1,606,881	963,583	219,059	108,285	2,683	1,341
11	Test Year Distribution Reserve	317	2,901,832	2,900,491	1,606,881	963,583	219,059	108,285	2,683	1,341
12	General, Common & Intangible									
13	General: Power Control Center	314	0	0	0	0	0	0	0	0
14	General: Functionalized	502	109,502	109,072	57,923	28,011	20,653	2,442	43	430
15	General: Reallocated to Gas	DIR	0	-	-	-	-	-	-	-
16	Common: Functionalized	502	187,030	186,295	98,933	47,843	35,275	4,170	73	735
17	Intangible Amortization Reserve	502	452,981	451,200	239,612	115,875	85,436	10,100	177	1,781
18	Total General, Common & Intangible		749,513	746,567	396,468	191,730	141,364	16,712	293	2,946

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CWIP

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production CWIP									
2	Production	220	267,902	265,455	109,061	63,370	92,128	825	70	2,447
3	Production: Gas Plant	220	0	0	0	0	0	0	0	0
3	Production: 7 Classics	220	0	0	0	0	0	0	0	0
4	Total Production		267,902	265,455	109,061	63,370	92,128	825	70	2,447
5	Transmission CWIP									
6	Transmission	228	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
7	Subtransmission	122	0	0	0	0	0	0	0	0
8	Total Transmission		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
9	Distribution CWIP									
10	HV Distribution	122	41,546	41,520	17,855	11,124	12,087	276	178	26
11	Distribution	306	77,157	77,155	44,481	26,256	4,404	2,010	4	2
12	Other	220	0	0	0	0	0	0	0	0
13	Total Distribution		118,703	118,676	62,336	37,380	16,491	2,286	182	27
14	General/Common/Intangible CWIP									
15	General	502	16,480	16,415	8,717	4,216	3,108	367	6	65
16	Intangible	502	37,800	37,651	19,995	9,669	7,129	843	15	149
17	Common	502	45,866	45,686	24,262	11,733	8,651	1,023	18	180
18	Plant Held for Future Use	502	0	0	0	0	0	0	0	0
19	Other	502	0	0	0	0	0	0	0	0
20	Total Gen/Comm/Int		100,146	99,752	52,974	25,618	18,888	2,233	39	394

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Working Capital

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Current+Accrued Assets									
2	Cash & Cash Equivalents	316	58,344	58,098	28,606	16,595	11,996	867	35	246
3	Accts Receivable	143	298,207	296,453	137,238	75,204	80,780	3,087	145	1,754
4	Material and Supplies	316	88,151	87,780	43,220	25,073	18,124	1,310	52	371
5	Fuel Stock	100	67,802	67,067	25,206	15,237	26,123	467	35	735
6	Real & Personal Property Taxes	316	179,830	179,073	88,171	51,150	36,974	2,672	106	757
7	Other Cur Assets	502	345,005	343,648	182,496	88,254	65,071	7,693	135	1,356
8	Deferred Debits	502	854,469	851,110	451,986	218,578	161,160	19,052	334	3,359
9	Total Current Assets		1,891,807	1,883,229	956,922	490,091	400,225	35,148	842	8,578
10	Current+Accrued Liab									
11	Accounts Payable	316	394,800	393,138	193,570	112,296	81,172	5,867	234	1,662
12	Customer Deposits	143	17,274	17,173	7,950	4,356	4,679	179	8	102
13	Dividends Declared	316	20,560	20,473	10,080	5,848	4,227	306	12	87
14	Accrued Interest	316	44,462	44,275	21,800	12,647	9,142	661	26	187
15	Accrued Taxes - Federal	502	7,531	7,501	3,984	1,926	1,420	168	3	30
16	Accrued Taxes - MSBT	601	2,582	2,571	1,315	698	509	48	1	11
17	Accrued Taxes - R&PP & Other	316	154,890	154,238	75,943	44,056	31,846	2,302	92	652
18	Other Current Liabilities	502	20,266	20,186	10,720	5,184	3,822	452	8	80
19	Deferred CR	502	425,431	423,758	225,039	108,828	80,240	9,486	166	1,672
20	Total Current Liabilities		1,087,796	1,083,314	550,401	295,839	217,057	19,467	551	4,481
21	Total Working Capital		804,011	799,915	406,522	194,252	183,169	15,681	292	4,096

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Adjustments to Rate Base

Line No.	(a) Description		(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Additions to Rate Base										
2	Sales and Use Tax Adjustment		309	0	0	0	0	0	0	0	0
3		0	100	0	0	0	0	0	0	0	0
4		0	220	0	0	0	0	0	0	0	0
5		0	263	0	0	0	0	-	0	-	-
6	Total Additions			0	0	0	0	0	0	0	0
7	Construction Funds Retained from Contractors		330	0	0	0	0	0	0	0	0
8	Customer Advances		309	58,242	58,201	31,683	18,859	6,321	1,289	50	41
9		0	263	0	0	0	0	-	0	-	-
10		0	100	0	0	0	0	0	0	0	0
11		0	100	0	0	0	0	0	0	0	0
12	Total Deductions			58,242	58,201	31,683	18,859	6,321	1,289	50	41
13	Total Adjustments to Rate Base			(58,242)	(58,201)	(31,683)	(18,859)	(6,321)	(1,289)	(50)	(41)

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Revenue

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Rate Revenue									
2	Revenue From Electric Sales	DIR	2,179,688	2,168,544	1,194,723	613,039	329,045	29,702	2,036	11,144
3	Provision for Rate Refund	DIR	0	-	-	-	-	-	-	-
4	Unbilled Revenue	DIR	0	-	-	-	-	-	-	-
5	Non PSCR Rate Revenue		2,179,688	2,168,544	1,194,723	613,039	329,045	29,702	2,036	11,144
6	PSCR Base Revenue	DIR	2,008,330	1,994,718	733,922	443,601	803,595	13,600	-	13,612
7	Unbilled PSCR Base Revenue	DIR	0	-	-	-	-	-	-	-
8	GSG Market Price Revenue	DIR	1,548	1,548	-	-	-	-	1,548	-
9	PSCR Rate Revenue		2,009,878	1,996,266	733,922	443,601	803,595	13,600	1,548	13,612
10	Total Rate Revenue		4,189,566	4,164,811	1,928,645	1,056,640	1,132,640	43,302	3,584	24,755
11	Revenue Credits									
12	Late Payment Charge Revenue	DIR	10,227	10,227	5,713	2,931	1,573	-	10	-
13	Renewable Resource Surcharge	150	0	0	0	0	0	0	0	0
14	ERIP	DIR	(0)	-	-	-	-	-	-	(0)
15	Pole Rental Rev	307	11,114	11,112	6,355	3,796	877	77	6	2
16	Other Rents	316	10,041	10,034	5,522	3,201	1,069	234	8	7
17	Enhanced Security Surcharge	DIR	(0)	-	-	-	-	-	-	(0)
18	Interdepartmental	150	0	0	0	0	0	0	0	0
19	Reg Asset 10d(4)	DIR	(0)	-	-	-	-	-	-	(0)
20	PLM Revenues	255	0	0	0	0	0	0	0	-
21	Purchased Power Administrative Fees	100	958	948	356	215	369	7	0	10
22	Miscellaneous Service & Reconnect Fees	253	1,249	1,249	539	336	364	10	0	-
23	Other Revenues	150	4,444	4,398	1,449	903	2,018	27	2	45
24	Securitization Surcharge	DIR	(0)	-	-	-	-	-	-	(0)
25	Job Work Revenue	414	14,201	14,201	7,876	4,387	1,290	640	8	-
26	Non PSCR Revenue Credits		52,233	52,169	27,810	15,769	7,560	995	34	64
27	PSCR Factor Revenue	DIR	26,584	26,584	9,781	5,912	10,709	181	-	-
28	Unbilled PSCR Factor Revenue	DIR	0	-	-	-	-	-	-	-
29	Intersystem Sales	222	80,222	80,190	32,945	19,143	27,832	249	21	32
30	GSG Market Price Capacity Revenue	DIR	0	-	-	-	-	-	-	-
31	PSCR Revenue Credits		106,806	106,774	42,726	25,055	38,541	431	21	32
32	Total Revenue Credits		159,038	158,942	70,536	40,824	46,101	1,426	55	96
33	Total Revenue		4,348,605	4,323,753	1,999,181	1,097,464	1,178,741	44,728	3,639	24,851

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O&M (production) 1

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Fuel and Purchased Power									
2	Mid-Peak Summer Fuel for Gen	103	78,529	77,678	28,495	18,327	30,547	271	38	851
3	On-Peak Winter Fuel for Gen	105	204,558	202,341	72,949	48,720	79,562	1,018	92	2,217
4	Off-Peak Summer Fuel for Gen	104	70,952	70,183	27,297	14,589	27,603	647	47	769
5	Off-Peak Winter Fuel for Gen	106	138,019	136,523	53,575	29,477	52,000	1,396	75	1,496
6	Critical Summer Peak Energy	107	38,253	37,838	13,670	9,610	14,430	114	15	415
7	Total Fuel Expense		530,311	524,562	195,987	120,722	204,141	3,446	266	5,749
8	Mid-Peak Summer Purchased Power	103	65,690	64,978	23,836	15,331	25,552	227	32	712
9	On-Peak Winter Purchased Power	105	171,112	169,258	61,022	40,754	66,553	851	77	1,855
10	Off-Peak Summer Purchased Power	104	59,351	58,708	22,834	12,204	23,090	541	39	643
11	Off-Peak Winter Purchased Power	106	115,453	114,201	44,816	24,657	43,498	1,168	62	1,252
12	Critical Peak Summer Purchased Power	107	31,998	31,651	11,435	8,038	12,071	95	12	347
13	Purchased Power Capacity	220	710,811	704,317	289,367	168,137	244,437	2,190	186	6,494
14	Total P&I		1,154,415	1,143,113	453,309	269,121	415,201	5,072	409	11,302
15	Total Fuel and P&I		1,684,726	1,667,675	649,296	389,844	619,343	8,518	675	17,051

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O&M (production) 2

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Fossil Plant O&M Total									
2	Capacity Related Operations	220	41,677	41,296	16,966	9,858	14,332	128	11	381
3	Capacity Related Maintenance	220	4,728	4,685	1,925	1,118	1,626	15	1	43
4	Energy Related Operations	100	7,228	7,150	2,687	1,624	2,785	50	4	78
5	Energy Related Maintenance	100	50,599	50,051	18,810	11,371	19,495	349	26	548
6	Capacity Related Fuel Handling	220	0	0	0	0	0	0	0	0
7	Energy Related Fuel Handling	100	13,437	13,291	4,995	3,020	5,177	93	7	146
8	Total Fossil O&M Total		117,668	116,472	45,384	26,991	43,414	634	49	1,196
9	Nuclear Plant O&M Total									
10	Capacity Related Operations	220	0	0	0	0	0	0	0	0
11	Capacity Related Maintenance	220	0	0	0	0	0	0	0	0
12	Energy Related Maintenance	100	0	0	0	0	0	0	0	0
13	523 Electric Expenses	220	0	0	0	0	0	0	0	0
14	524 Miscellaneous	220	0	0	0	0	0	0	0	0
15	Total Nuc O&M Total		0	0	0	0	0	0	0	0
16	Hydro Plant O&M Total									
17	Capacity Related Operations	220	8,667	8,587	3,528	2,050	2,980	27	2	79
18	Capacity Related Maintenance	220	937	928	381	222	322	3	0	9
19	Energy Related Operations	100	981	971	365	221	378	7	1	11
20	Energy Related Maintenance	100	4,321	4,274	1,606	971	1,665	30	2	47
21	540 Rents	220	0	0	0	0	0	0	0	0
22	Total Hydro O&M Total		14,906	14,760	5,881	3,463	5,345	66	5	145
23	Other Power O&M Total									
24	Capacity Related Operations & Maintenance	220	38,840	38,485	15,811	9,187	13,356	120	10	355
25	Energy Related Operations & Maintenance	100	0	0	0	0	0	0	0	0
26	0	100	0	0	0	0	0	0	0	0
27	Total Other Power O&M Total		38,840	38,485	15,811	9,187	13,356	120	10	355
28	Other Power Supply Expense									
29	Capacity Related Sys Cntl Load Disp	220	10,151	10,059	4,133	2,401	3,491	31	3	93
30	Energy Related Sys Cntl Load Disp	100	0	0	0	0	0	0	0	0
31	Total Other O&M Expense		10,151	10,059	4,133	2,401	3,491	31	3	93
32	Disposition of Allowances	220	0	0	0	0	0	0	0	0
33	Total Production O&M Excluding Fuel and P&I		181,565	179,776	71,208	42,043	65,607	851	67	1,789
34	Total Prod O&M Expense		1,866,291	1,847,451	720,504	431,887	684,950	9,369	742	18,840

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O&M (transmission & adjustments)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Transmission O&M									
2	Transmission	120	439,642	435,365	182,312	101,010	149,596	2,360	88	4,277
3	Miscellaneous	127	0	0	0	0	0	0	0	0
4	Other	120	0	0	0	0	0	0	0	0
5	Total Transmission Expense		439,642	435,365	182,312	101,010	149,596	2,360	88	4,277
6	O&M Adjustments									
7	Tax Benefit of Proforma Interest & Interest Synchronization Adjustment	150	0	0	0	0	0	0	0	0
8	Other Advertising Programs - Disallowance	412	0	0	0	0	0	0	0	0
9	Income Tax Effect of Interest	390	0	0	0	0	0	0	0	0
10	Charitable, Civic, Dues & Donations	412	0	0	0	0	0	0	0	0
11	Transmission reclass (indirect costs)	DIR	0	-	-	-	-	-	-	-
12	Streetlighting O&M	DIR	0	-	-	-	-	-	-	-
13	Customer O&M	411	0	0	0	0	0	0	0	0
14	Administrative and General O&M	412	0	0	0	0	0	0	0	0
15	Other O&M Inflation	443	0	0	0	0	0	0	0	0
16	Other O&M Adjmts	438	0	0	0	0	0	0	0	0
17	Total O&M Adjustments		0	0	0	0	0	0	0	0

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O&M (distribution)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Operation									
2	580 Supv & Engineering - Distribution	400	25,089	25,084	13,877	6,622	1,807	2,770	7	5
3	580 Supv & Engineering - 138kV	402	191	190	80	46	63	0	0	2
4	580 Supv & Engineering - 46kV	404	1,992	1,990	856	533	579	13	9	1
5	581 Load Dispatch - Distribution	301	0	0	0	0	0	0	0	0
6	582 Station Expense - Distribution	230	2,022	2,022	951	593	464	15	0	-
7	582 Station Expense - 138kV	303	0	0	0	0	0	0	0	0
8	582 Station Expense - 46kV	304	0	0	0	0	0	0	0	0
9	583 Overhead Expense - Distribution	307	6,753	6,752	3,862	2,307	533	47	4	1
10	583 Overhead Expense - 138kV	121	67	67	28	16	22	0	0	1
11	583 Overhead Expense - 46kV	122	700	699	301	187	204	5	3	0
12	584 Underground Exp	308	3,978	3,978	2,383	1,485	74	37	0	-
13	585 St Lt	311	2,559	2,557	-	-	-	2,557	-	2
14	586 - Metering Expense	313	3,721	3,721	2,242	1,014	463	1	1	0
15	587 Cust Instl Expense	160	3,400	3,400	2,989	401	8	1	0	0
16	588 Miscellaneous	400	15,249	15,246	8,435	4,025	1,099	1,683	4	3
17	589 Rents	309	2,050	2,049	1,115	664	223	45	2	1
18	Total Dist Operation Expense		67,771	67,754	37,119	17,893	5,538	7,174	29	17
19	Distribution Maintenance									
20	590 Supv & Engineering - Distribution	401	6,873	6,872	3,880	2,318	593	78	3	1
21	590 Supv & Engineering - 138kV	403	125	124	48	30	44	1	0	1
22	590 Supv & Engineering - 46kV	405	216	216	93	58	63	1	1	0
23	591 Structures - Distribution	230	436	436	205	128	100	3	0	-
24	591 Structures - 138kV	303	48	47	18	11	17	0	0	0
25	591 Structures - 46kV	304	54	54	23	14	16	0	0	0
26	592 Station Equipment - Distribution	230	8,610	8,610	4,049	2,523	1,975	63	1	-
27	592 Station Equipment - 138kV	303	1,592	1,579	614	382	567	9	6	13
28	592 Station Equipment - 46kV	304	1,806	1,805	776	484	525	12	8	1
29	593 Overhead Lines - Distribution	307	83,186	83,173	47,570	28,415	6,565	578	45	13
30	593 Overhead Lines - 138kV	224	111	111	47	27	37	0	0	-
31	593 Overhead Lines - 46kV	122	1,156	1,155	497	310	336	8	5	1
32	594 Underground Lines - Distribution	308	4,152	4,152	2,487	1,550	77	38	0	-
33	594 Underground Lines - 138kV	121	0	0	0	0	0	0	0	0
34	594 Underground Lines - 46kV	122	23	23	10	6	7	0	0	0
35	595 Line Xfmrs	312	8,687	8,687	5,148	3,207	252	80	0	-
36	596 St Lts & OPL	311	473	472	-	-	-	472	-	0
37	597 Meters	313	3,464	3,464	2,087	944	431	1	1	0
38	598 Miscellaneous	401	232	232	131	78	20	3	0	0
39	Total Dist Maintenance Expense		121,245	121,214	67,684	40,485	11,626	1,348	70	31
40	Total Distribution O&M Expense		189,016	188,968	104,804	58,378	17,164	8,523	100	48

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O&M (customer & A&G)

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1	Customer Accounts Expense									
2	901 Supervision	408	5,626	5,626	4,953	664	8	1	0	0
3	902 Meter Reading	263	14,313	14,313	12,618	1,693	-	2	-	-
4	903 Rcrds & Collection	160	5,928	5,928	5,213	699	14	2	0	0
5	904 Uncollectibles	264	18,594	18,594	16,357	2,194	43	-	0	0
6	905 Misc Expenses	408	0	0	0	0	0	0	0	0
7	Total Customer Accounts		44,461	44,461	39,141	5,251	64	5	0	0
8	Customer Services									
9	907 Supervision	160	545	545	480	64	1	0	0	0
10	908 Customer Assist	603	5,870	5,810	1,914	1,192	2,665	35	3	60
11	909 Info & Inst	160	2,278	2,278	2,003	269	5	1	0	0
12	910 Miscellaneous	160	0	0	0	0	0	0	0	0
13	Total Customer Services		8,693	8,634	4,397	1,525	2,672	37	3	60
14	Sales Expense									
15	911 Supervision	160	0	0	0	0	0	0	0	0
16	912 Demo & Selling	160	165	165	145	20	0	0	0	0
17	913 Advertising	160	0	0	0	0	0	0	0	0
18	916 Miscellaneous	160	0	0	0	0	0	0	0	0
19	Total Sales Expense		165	165	145	20	0	0	0	0
20	Administrative & General									
21	Production	500	62,661	62,088	25,509	14,822	21,548	193	16	572
22	HV Distribution	406	3,868	3,858	1,623	1,008	1,187	24	15	10
23	Distribution	407	86,596	86,583	48,553	26,920	7,000	4,079	32	13
24	Customer	409	19,351	19,329	15,850	2,467	996	15	1	22
25	Total Admin & General		172,475	171,859	91,534	45,216	30,732	4,312	65	617
26	Total O&M Excluding PSCR Expense		596,376	593,863	311,229	152,433	116,239	13,727	235	2,514
27	Total O & M Expense		2,720,745	2,696,903	1,142,837	643,286	885,178	24,605	998	23,842

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Depreciation Expense Summary

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	Production									
2	Production Depreciation Expense		293,358	290,678	119,424	69,392	100,881	904	77	2,680
3	GSU Depreciation Expense		0	0	0	0	0	0	0	0
4	Production Test Year Change	220	0	0	0	0	0	0	0	0
5	Total Production		293,358	290,678	119,424	69,392	100,881	904	77	2,680
6	Transmission									
7	Bulk Power Transm		0	-	-	-	-	-	-	-
8	Transm; Subtrans		0	0	0	0	0	0	0	0
9	Subtransmission		0	0	0	0	0	0	0	0
10	Total Transmission		0	0	0	0	0	0	0	0
11	Distribution									
12	Stations and Equipment		59,707	59,602	29,780	18,549	10,684	460	130	105
13	Overhead System		110,330	110,314	64,982	40,488	3,785	1,005	54	16
14	Underground System		18,009	18,009	10,788	6,721	333	167	0	-
15	Meters and Svc Drops		56,111	56,110	35,341	16,893	3,568	299	8	1
16	St Lgts and OPL		4,226	4,222	-	-	-	4,222	-	4
17	Test Year Distribution Change	444	0	0	0	0	0	0	0	0
18	Total Distribution		248,383	248,257	140,891	82,651	18,370	6,153	193	126
19	General/Common/Intangible									
20	Total Gen/Comm/Int		113,668	113,221	60,127	29,077	21,439	2,534	44	447
21	Test Year Gen/Comm/Int Change	445	0	0	0	0	0	0	0	0
22	Total General/Common/Intangible Dep Expense		113,668	113,221	60,127	29,077	21,439	2,534	44	447
23	Total Other Amortization Expense		0	0	0	0	0	0	0	0
24	Total Depreciation & Amortization Expense		655,409	652,156	320,442	181,119	140,690	9,591	314	3,253
25	Test Year Dep & Amort Exp	442	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	314	3,253

Projected 12-Month Period Ending Dec 31, 2019
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4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Depreciation Expense (prod & tran)

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	Production									
2	Direct		-	-	-	-	-	-	-	-
3	Fossil	220	210,412	208,490	85,657	49,771	72,358	648	55	1,922
4	Nuclear	220	0	0	0	0	0	0	0	0
5	Hydro	220	41,350	40,972	16,833	9,781	14,220	127	11	378
6	Other Production	220	41,596	41,216	16,933	9,839	14,304	128	11	380
7	Distribution GSUs	220	0	0	0	0	0	0	0	0
8	Jackson Gas Plant	220	0	0	0	0	0	0	0	0
9	7 Classics	220	0	-	-	-	-	-	-	-
10	Total Production Depreciation Expense		293,358	290,678	119,424	69,392	100,881	904	77	2,680
11	Transmission									
12	Direct		0	-	-	-	-	-	-	-
13	Transmission	127	0	0	0	0	0	0	0	0
14	Subtransmission	123	0	0	0	0	0	0	0	0
15	Total Transmission Depreciation Expense		0	0	0	0	0	0	0	0

Projected 12-Month Period Ending Dec 31, 2019
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Depreciation Expense (distribution)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution									
2	360A Land & Rights-Direct		-	-	-	-	-	-	-	-
3	138kV Substations/Overheads (METC)	127	336	334	130	81	120	2	1	3
4	138kV Substations/Overheads	127	175	174	68	42	62	1	1	1
5	46kV Substations/Overheads	124	509	508	219	136	148	3	2	0
6	Substations/Overheads (Assignable)	DIR	0	-	-	-	-	-	-	-
7	Overhead Lines Land & ROW	307	416	416	238	142	33	3	0	0
8	Total		1,436	1,432	654	401	363	9	4	5
9	Distribution Substations & Equipment									
10	Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
11	138kV HV Subtran/Dist Substations	127	10,786	10,697	4,157	2,590	3,844	64	42	89
12	Distribution Substations	124	19,472	19,460	8,368	5,214	5,665	129	84	12
13	Total		30,258	30,157	12,526	7,804	9,509	194	125	101
14	Overhead System									
15	138kV HV Subtran/Dist Overhead Lines	127	1,108	1,099	427	266	395	7	4	9
16	46kV Subtran Overheads & Transformer Platforms	122	11,651	11,644	5,007	3,120	3,390	77	50	7
17	Overhead System	305	97,571	97,571	59,548	37,102	-	921	-	-
19	Total		110,330	110,314	64,982	40,488	3,785	1,005	54	16
20	Underground System									
21	Underground System	308	18,009	18,009	10,788	6,721	333	167	0	-
22	Total		18,009	18,009	10,788	6,721	333	167	0	-
23	Distribution Line Equipment									
24	Line Equipment	312	28,013	28,013	16,601	10,343	812	257	0	-
25	Total		28,013	28,013	16,601	10,343	812	257	0	-
26	Distributions Services									
27	Overhead & Underground Services	310	27,147	27,147	18,065	9,081	-	-	-	-
28	Total		27,147	27,147	18,065	9,081	-	-	-	-

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Depreciation Expense (dist & general)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution (cont.)									
2	Distribution Metering Equipment		-	-	-	-	-	-	-	-
3	Metering Equipment	170	28,671	28,670	17,276	7,812	3,568	6	8	1
4	Total		28,671	28,670	17,276	7,812	3,568	6	8	1
5	Installations on Customer Premises L4	DIR	293	293	-	-	-	293	-	-
6	Street & Highway Lighting Depreciation Expense	311	4,226	4,222	-	-	-	4,222	-	4
7	Total Distribution Depreciation Expense		248,383	248,257	140,891	82,651	18,370	6,153	193	126
8	General/Common/Intangible									
9	General	502	11,885	11,838	6,287	3,040	2,242	265	5	47
10	Common	502	20,412	20,332	10,797	5,222	3,850	455	8	80
11	Intangible Amortization	502	81,371	81,051	43,043	20,815	15,347	1,814	32	320
12	Total Gen/Comm/Int Depreciation Expense		113,668	113,221	60,127	29,077	21,439	2,534	44	447
13	Other Amortization									
14	Amort of 7 Classics Inventory	220	0	0	0	0	0	0	0	0
15	AFUDC in Excess of FERC Rate	330	0	0	0	0	0	0	0	0
16	Securitized Regulatory Assets (MPSC Case U-12505)	150	0	0	0	0	0	0	0	0
17	ARO Accretion/Transition Expense	220	0	0	0	0	0	0	0	0
18	Total Other Amortization Expense		0	0	0	0	0	0	0	0
19	Total Depreciation & Amortization Expense		655,409	652,156	320,442	181,119	140,690	9,591	314	3,253

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Tax

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	City Income Tax	150	1,299	1,285	423	264	590	8	1	13
2	Michigan Single Business Tax	601	0	0	0	0	0	0	0	0
3	Michigan Business Tax	439	38,881	39,038	22,107	10,964	5,476	381	111	(157)
3	R&PP Taxes - Prod	220	65,038	64,444	26,477	15,384	22,366	200	17	594
4	R&PP Taxes - High Voltage Dist	302	21,547	21,533	9,260	5,769	6,268	143	92	13
5	R&PP Taxes - Low Voltage Dist	306	67,163	67,162	38,720	22,855	3,834	1,750	3	1
6	R&PP Taxes - General	315	3,081	3,068	1,618	786	596	67	1	13
7	R&PP Taxes - Common/Intangible	502	12,534	12,484	6,630	3,206	2,364	279	5	49
8	R&PP Taxes - PHFFU	226	38	38	17	10	11	0	0	-
9	R&PP Taxes - CWIP	330	0	0	0	0	0	0	0	0
10	Total R&PP Taxes		169,400	168,729	82,721	48,011	35,438	2,440	119	671
11	Payroll Related Taxes	502	21,509	21,424	11,377	5,502	4,057	480	8	85
12	Miscellaneous General Taxes	150	0	0	0	0	0	0	0	0
13	Total Payroll/Miscellaneous Taxes		21,509	21,424	11,377	5,502	4,057	480	8	85
14	MPSC Assessment Fee	150	9,266	9,172	3,022	1,882	4,207	56	4	94
15	Total Other Taxes		240,354	239,648	119,651	66,623	49,768	3,364	243	706
16	Federal Income Tax Provision	439	110,944	111,391	63,080	31,284	15,625	1,086	316	(447)
17	Total Taxes Other Than Income		201,473	200,611	97,544	55,659	44,292	2,983	132	863
18	Total Income Taxes		149,825	150,429	85,187	42,248	21,101	1,467	427	(604)
19	Total Taxes		351,299	351,040	182,731	97,907	65,393	4,450	559	259

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1

Case No.: U-20134
Exhibit No.: A-16 (JCA-1)
Schedule: F-1

Witness: JCAponte
Date: May 2018

Projected 12-Month Period Ending Dec 31, 2019
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Adjustments to Income Statement

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Adjustments to NOI - Miscellaneous	316	0	0	0	0	0	0	0	0
2	Interest Expense Securitization I	150	0	0	0	0	0	0	-	0
3	Gain/Losses from Disposition of Utility Plant	316	0	0	0	0	0	0	0	0
4	Disallowed Corp Memb	502	0	0	0	0	0	0	0	0
5	Advertising	225	0	0	0	0	0	0	0	0
6	Interest Synch Adj	390	0	0	0	0	0	0	0	0
7	Allowable Charitable	140	0	0	0	0	0	0	0	0
8	MERC Consolidation	220	0	0	0	0	0	0	0	0
9	Clean Air Act	226	0	0	0	0	0	0	0	-
10	AFUDC	330	8,834	8,782	4,072	2,293	2,314	97	5	52
11	Income Tax Adjustment	226	0	0	0	0	0	0	0	-
12	Total Other Adjustments		8,834	8,782	4,072	2,293	2,314	97	5	52

Projected 12-Month Period Ending Dec 31, 2019
Version 2
4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Summary
RETURN

Line No.	(a) Description	(b)	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Total Rate Base		10,715,023	10,670,808	5,469,116	2,903,301	2,172,275	120,885	5,231	44,215
2	Total Rate Revenue		4,189,566	4,164,811	1,928,645	1,056,640	1,132,640	43,302	3,584	24,755
3	Total Revenue Credits		159,038	158,283	72,432	40,517	43,770	1,509	54	755
4	Total Revenue		4,348,605	4,323,094	2,001,077	1,097,157	1,176,410	44,811	3,638	25,511
5	Expenses:									
6	Fuel and P&I Expense		1,684,726	1,668,042	663,361	392,397	602,260	9,317	706	16,685
7	Transmission Expense		439,642	435,533	185,335	102,122	145,684	2,297	94	4,109
8	Other O & M Expense		596,376	593,951	320,340	149,042	110,490	13,869	210	2,425
9	Depreciation & Amortization Expense		655,409	652,335	335,154	176,713	130,266	9,922	280	3,074
10	Other Taxes		240,354	239,614	121,282	65,664	49,067	3,375	225	740
11	Federal Income Taxes		110,944	111,175	56,920	32,009	21,010	914	322	(231)
12	Total Expenses		3,727,452	3,700,649	1,682,394	917,947	1,058,778	39,694	1,837	26,803
13	Net Operating Income		621,152	622,444	318,683	179,210	117,632	5,117	1,801	(1,292)
14	Other Income Adjustments		8,834	8,785	4,242	2,274	2,162	103	5	49
15	Adjusted Net Operating Income		629,986	631,229	322,925	181,483	119,794	5,220	1,806	(1,243)
16	Rate of Return on Rate Base		5.88%	5.92%	5.90%	6.25%	5.51%	4.32%	34.53%	-2.81%
17	Index of Return (Jurisdictional)			100	100	106	93	73	584	
18	Return on Rate Base @ 6.33%		678,581	675,781	346,359	183,866	137,570	7,656	331	2,800
19	Income Deficiency (Sufficiency)		48,595	44,552	23,433	2,382	17,776	2,435	(1,475)	4,043
20	Revenue Deficiency (Sufficiency)		65,073	59,659	31,379	3,190	23,803	3,261	(1,975)	5,414
21	Revenue Requirement/Total Cost of Service		4,413,677	4,382,752	2,032,456	1,100,347	1,200,213	48,072	1,663	30,925
22	Less: Revenue Credits		159,038	158,283	72,432	40,517	43,770	1,509	54	755
23	Proposed Rate Design Revenue		4,254,639	4,224,469	1,960,024	1,059,830	1,156,443	46,563	1,609	30,169
24	Production: Net Capacity Cost		1,039,771	1,030,867	448,627	252,188	328,032	1,800	219	8,904
25	Production: Capacity Related Cost Offset		621,419	614,884	256,775	144,968	207,572	5,311	259	6,535
26	Production: Non-Capacity Related Cost		1,373,165	1,358,389	525,105	313,241	510,866	8,586	590	14,776
27	Distribution: Demand Related Cost		1,029,464	1,029,569	584,011	312,725	101,883	30,418	533	(106)
28	Distribution: Customer Related Cost		190,820	190,759	145,506	36,709	8,090	448	8	60
29	Full Service MWH Sales		33,639,746	33,258,060	12,226,200	7,390,670	13,396,515	226,556	18,120	381,686
30	ROA MWH Sales		3,852,071	3,852,071	-	225,216	3,626,855	-	-	-
31	MWH Sales		37,491,817	37,110,131	12,226,200	7,615,885	17,023,370	226,556	18,120	381,686
32	Customers		1,824,591	1,824,589	1,604,424	215,234	4,183	738	10	2

Projected 12-Month Period Ending Dec 31, 2019
Version 2
4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Residential/Secondary
RETURN

Line No.	(a) Description	(b) Rate Residential	(c) Rate RT	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Rate GS GEI	(h) Rate GSD GEI	(i) Total Commercial Secondary
1	Total Rate Base	5,469,116	-	5,469,116	1,594,849	1,162,566	50,480	95,406	2,903,301
2	Total Rate Revenue	1,928,645	-	1,928,645	556,102	458,132	13,119	29,287	1,056,640
3	Total Revenue Credits	72,432	-	72,432	21,597	17,187	583	1,150	40,517
4	Total Revenue	2,001,077	-	2,001,077	577,699	475,319	13,702	30,437	1,097,157
5	Expenses:								
6	Fuel and P&I Expense	663,361	-	663,361	200,128	177,714	4,775	9,779	392,397
7	Transmission Expense	185,335	-	185,335	52,330	45,698	1,317	2,777	102,122
8	Other O & M Expense	320,340	-	320,340	85,168	56,920	2,435	4,519	149,042
9	Depreciation & Amortization Expense	335,154	-	335,154	97,962	70,433	2,892	5,426	176,713
10	Other Taxes	121,282	-	121,282	35,631	26,928	1,010	2,095	65,664
11	Federal Income Taxes	56,920	-	56,920	16,137	14,795	193	885	32,009
12	Total Expenses	1,682,394	-	1,682,394	487,354	392,488	12,623	25,482	917,947
13	Net Operating Income	318,683	-	318,683	90,345	82,832	1,079	4,955	179,210
14	Other Income Adjustments	4,242	-	4,242	1,229	943	35	67	2,274
15	Adjusted Net Operating Income	322,925	-	322,925	91,573	83,774	1,114	5,022	181,483
16	Rate of Return on Rate Base	5.90%	0.00%	5.90%	5.74%	7.21%	2.21%	5.26%	6.25%
17	Index of Return (Jurisdictional)	100	-	100	97	122	37	89	106
18	Return on Rate Base @ 6.33%	346,359	-	346,359	101,002	73,625	3,197	6,042	183,866
19	Income Deficiency (Sufficiency)	23,433	-	23,433	9,428	(10,149)	2,083	1,020	2,382
20	Revenue Deficiency (Sufficiency)	31,379	-	31,379	12,625	(13,590)	2,789	1,366	3,190
21	Revenue Requirement/Total Cost of Service	2,032,456	-	2,032,456	590,324	461,729	16,491	31,803	1,100,347
22	Less: Revenue Credits	72,432	-	72,432	21,597	17,187	583	1,150	40,517
23	Proposed Rate Design Revenue	1,960,024	-	1,960,024	568,728	444,542	15,908	30,653	1,059,830
24	Production: Net Capacity Cost	448,627	-	448,627	130,081	113,049	3,049	6,010	252,188
25	Production: Capacity Related Cost Offset	256,775	-	256,775	74,896	64,999	1,754	3,318	144,968
26	Production: Non-Capacity Related Cost	525,105	-	525,105	158,849	142,258	3,900	8,234	313,241
27	Distribution: Demand Related Cost	584,011	-	584,011	173,128	119,791	6,920	12,885	312,725
28	Distribution: Customer Related Cost	145,506	-	145,506	31,773	4,444	285	206	36,709
29	Full Service MWH Sales	12,226,200	-	12,226,200	3,722,116	3,391,992	88,967	187,595	7,390,670
30	ROA MWH Sales	-	-	-	6,716	140,339	15,206	62,955	225,216
31	MWH Sales	12,226,200	-	12,226,200	3,728,832	3,532,331	104,173	250,549	7,615,885
32	Customers	1,604,424	-	1,604,424	192,544	20,212	1,636	841	215,234

Projected 12-Month Period Ending Dec 31, 2019
Version 2
4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Primary & Lighting
RETURN

Line No.	(a) Description	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) - Rate GU-XL	(o) Rate GU	(p) Total Lighting & Unmetered
1	Total Rate Base	269,447	365,116	315,604	1,050,215	46,688	38,585	5,396	13,666	67,558	2,172,275	5,623	98,820	11	16,431	120,885
2	Total Rate Revenue	142,017	214,613	179,943	515,187	21,951	21,746	2,051	5,523	29,609	1,132,640	1,743	33,239	2	8,318	43,302
3	Total Revenue Credits	4,813	9,104	7,009	19,738	746	913	124	247	1,076	43,770	68	1,164	0	278	1,509
4	Total Revenue	146,830	223,717	186,952	534,925	22,696	22,659	2,175	5,770	30,685	1,176,410	1,810	34,403	2	8,596	44,811
5	Expenses:															
6	Fuel and P&I Expense	59,735	144,452	101,465	255,296	8,900	15,258	1,944	2,896	12,313	602,260	598	4,812	0	3,907	9,317
7	Transmission Expense	14,750	35,351	24,943	63,773	2,447	-	461	720	3,239	145,684	153	1,231	0	912	2,297
8	Other O & M Expense	12,813	20,616	16,838	51,846	2,165	2,180	288	617	3,127	110,490	403	12,576	1	890	13,869
9	Depreciation & Amortization Expense	15,089	24,837	21,098	59,687	2,364	2,538	373	885	3,395	130,266	360	8,557	1	1,004	9,922
10	Other Taxes	6,891	6,494	7,679	24,028	1,148	827	48	319	1,632	49,067	125	2,855	0	394	3,375
11	Federal Income Taxes	5,691	(1,217)	2,262	12,168	860	281	(142)	50	1,057	21,010	26	662	(0)	226	914
12	Total Expenses	114,968	230,533	174,285	466,798	17,884	21,085	2,972	5,488	24,765	1,058,778	1,665	30,694	2	7,333	39,694
13	Net Operating Income	31,862	(6,815)	12,666	68,127	4,812	1,574	(797)	282	5,920	117,632	146	3,709	(0)	1,263	5,117
14	Other Income Adjustments	250	392	350	1,010	40	40	6	15	58	2,162	4	85	0	14	103
15	Adjusted Net Operating Income	32,112	(6,423)	13,017	69,137	4,853	1,615	(791)	297	5,979	119,794	150	3,794	(0)	1,277	5,220
16	Rate of Return on Rate Base	11.92%	-1.76%	4.12%	6.58%	10.39%	4.19%	-14.66%	2.17%	8.85%	5.51%	2.67%	3.84%	-1.95%	7.77%	4.32%
17	Index of Return (Jurisdictional)	201	(30)	70	111	176	71	(248)	37	150	93	45	65	(33)	131	73
18	Return on Rate Base @ 6.33%	17,064	23,123	19,987	66,510	2,957	2,444	342	865	4,278	137,570	356	6,258	1	1,041	7,656
19	Income Deficiency (Sufficiency)	(15,048)	29,546	6,971	(2,627)	(1,896)	829	1,133	569	(1,700)	17,776	206	2,465	1	(236)	2,435
20	Revenue Deficiency (Sufficiency)	(20,150)	39,565	9,334	(3,518)	(2,539)	1,110	1,517	761	(2,277)	23,803	276	3,300	1	(317)	3,261
21	Revenue Requirement/Total Cost of Service	126,680	263,282	196,286	531,407	20,158	23,769	3,692	6,531	28,408	1,200,213	2,086	37,703	3	8,280	48,072
22	Less: Revenue Credits	4,813	9,104	7,009	19,738	746	913	124	247	1,076	43,770	68	1,164	0	278	1,509
23	Proposed Rate Design Revenue	121,868	254,178	189,277	511,669	19,412	22,856	3,567	6,284	27,332	1,156,443	2,019	36,539	3	8,002	46,563
24	Production: Net Capacity Cost	36,388	72,235	53,369	150,293	5,190	-	1,089	2,014	7,454	328,032	-	-	-	1,800	1,800
25	Production: Capacity Related Cost Offset	20,005	45,850	34,204	87,513	2,826	11,035	747	1,195	4,198	207,572	477	3,781	0	1,052	5,311
26	Production: Non-Capacity Related Cost	48,383	129,453	88,895	211,971	7,630	10,529	1,641	2,161	10,202	510,866	553	4,452	0	3,581	8,586
27	Distribution: Demand Related Cost	15,143	5,649	11,870	58,363	3,521	1,192	78	877	5,191	101,883	968	27,902	2	1,545	30,418
28	Distribution: Customer Related Cost	1,949	991	940	3,529	244	100	13	37	288	8,090	21	404	0	23	448
29	Full Service MWH Sales	1,215,945	3,496,839	2,344,117	5,419,133	185,056	383,083	44,170	54,795	253,378	13,396,515	14,989	120,653	14	90,900	226,556
30	ROA MWH Sales	46,511	1,053,383	1,317,337	955,479	24,079	-	2,836	75,246	151,985	3,626,855	-	-	-	-	-
31	MWH Sales	1,262,456	4,550,222	3,661,453	6,374,612	209,135	383,083	47,006	130,040	405,363	17,023,370	14,989	120,653	14	90,900	226,556
32	Customers	1,589	47	165	1,980	189	19	3	9	182	4,183	272	-	-	466	738

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Summary
Rate Base Summary

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description		Total Electric	Total Jurisdictional Electric	Total Residential	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
1	Net Plant									
2	Production		3,867,081	3,833,747	1,650,051	928,407	1,237,687	16,387	1,215	33,335
3	Transmission		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
4	Distribution		5,392,375	5,388,103	3,050,410	1,622,669	637,672	73,829	3,522	4,273
5	General/Common/Intangible		709,797	707,156	387,912	177,881	125,023	16,092	247	2,641
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0
7	Total Net Plant		9,969,253	9,929,005	5,088,372	2,728,957	2,000,382	106,309	4,985	40,249
8	Working Capital									
9	Total Current Assets		1,891,807	1,883,555	984,627	481,633	380,814	35,718	763	8,252
10	Total Current Liabilities		1,087,796	1,083,549	570,950	289,279	202,979	19,864	478	4,246
11	Total Working Capital		804,011	800,006	413,678	192,355	177,835	15,853	285	4,006
12	Additions to Rate Base		0	0	0	0	0	0	0	0
13	Deductions from Rate Base		58,242	58,203	32,934	18,011	5,942	1,277	39	39
14	Adjustments to Rate Base		(58,242)	(58,203)	(32,934)	(18,011)	(5,942)	(1,277)	(39)	(39)
15	Total Rate Base		10,715,023	10,670,808	5,469,116	2,903,301	2,172,275	120,885	5,231	44,215

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Residential/Secondary
Rate Base Summary

	(a)	(b)	(c)	(d)	-	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Rate Residential	Rate RT	Total Residential		Rate GS	Rate GSD	Rate GS GEI	Rate GSD GEI	Commercial Secondary
1	Net Plant									
2	Production	1,650,051	-	1,650,051		478,730	416,312	11,222	22,143	928,407
3	Transmission	(0)	-	(0)		(0)	(0)	(0)	(0)	(0)
4	Distribution	3,050,410	-	3,050,410		916,790	608,579	34,022	63,277	1,622,669
5	General/Common/Intangible	387,912	-	387,912		102,007	67,608	2,907	5,359	177,881
6	Plant Purchased/Sold	0	-	0		0	0	0	0	0
7	Total Net Plant	5,088,372	-	5,088,372		1,497,528	1,092,499	48,152	90,778	2,728,957
8	Working Capital									
9	Total Current Assets	984,627	-	984,627		269,681	189,819	7,621	14,513	481,633
10	Total Current Liabilities	570,950	-	570,950		162,089	113,079	4,919	9,192	289,279
11	Total Working Capital	413,678	-	413,678		107,592	76,740	2,702	5,321	192,355
12	Additions to Rate Base	0	-	0		0	0	0	0	0
13	Deductions from Rate Base	32,934	-	32,934		10,270	6,673	374	693	18,011
14	Adjustments to Rate Base	(32,934)	-	(32,934)		(10,270)	(6,673)	(374)	(693)	(18,011)
15	Total Rate Base	5,469,116	-	5,469,116		1,594,849	1,162,566	50,480	95,406	2,903,301

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Primary & Lighting
Rate Base Summary

Line No.	(a) Description	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) - Rate GU-XL	(o) Rate GU	(p) Total Lighting & Unmetered
1	Net Plant															
2	Production	134,115	267,813	197,558	554,563	19,148	25,581	4,025	7,403	27,480	1,237,687	1,071	8,624	1	6,690	16,387
3	Transmission	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
4	Distribution	100,055	41,780	72,423	356,960	21,849	7,383	642	4,616	31,964	637,672	3,677	62,584	6	7,563	73,829
5	General/Common/Intangible	15,127	21,533	18,643	60,174	2,545	2,191	319	779	3,713	125,023	460	14,675	2	956	16,092
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant	249,297	331,126	288,624	971,697	43,542	35,155	4,985	12,799	63,157	2,000,382	5,208	85,883	9	15,209	106,309
8	Working Capital															
9	Total Current Assets	45,657	69,039	58,464	179,042	7,535	7,127	930	2,240	10,782	380,814	1,123	31,695	4	2,896	35,718
10	Total Current Liabilities	24,612	34,684	30,675	97,270	4,191	3,625	513	1,321	6,089	202,979	662	17,610	2	1,591	19,864
11	Total Working Capital	21,045	34,355	27,789	81,772	3,344	3,502	416	919	4,693	177,835	461	14,085	2	1,305	15,853
12	Additions to Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Deductions from Rate Base	895	365	809	3,254	198	72	6	52	291	5,942	46	1,148	0	83	1,277
14	Adjustments to Rate Base	(895)	(365)	(809)	(3,254)	(198)	(72)	(6)	(52)	(291)	(5,942)	(46)	(1,148)	(0)	(83)	(1,277)
15	Total Rate Base	269,447	365,116	315,604	1,050,215	46,688	38,585	5,396	13,666	67,558	2,172,275	5,623	98,820	11	16,431	120,885

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Summary
O&M Summary

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	**Description**		**Total Electric**	**Total Jurisdictional Electric**	**Total Residential**	**Total Commercial Secondary**	**Total Primary**	**Total Lighting & Unmetered**	**Rate GSG**	**Total Non Jurisdictional**
1	Production									
2	Fuel Expense		530,311	524,562	196,060	120,744	204,062	3,433	263	5,749
3	Purchased & Interchange Power Expense		1,154,415	1,143,479	467,301	271,653	398,198	5,884	443	10,936
4	Total Fuel and P&I Expense		1,684,726	1,668,042	663,361	392,397	602,260	9,317	706	16,685
5	Fossil O&M Exp		117,668	116,496	46,293	27,155	42,308	688	51	1,173
6	Nuclear O&M Exp		0	0	0	0	0	0	0	0
7	Hydro O&M Exp		14,906	14,765	6,069	3,497	5,116	77	6	140
8	Peaker O&M Exp		38,840	38,505	16,573	9,325	12,431	165	12	335
9	Other O&M		10,151	10,064	4,332	2,437	3,249	43	3	88
10	Total Prod O&M Exp		181,565	179,830	73,266	42,414	63,105	972	73	1,735
11	Total Prod O&M Expense Including Fuel and P&I		1,866,291	1,847,872	736,627	434,811	665,365	10,290	778	18,420
12	Trans and Dist O&M									
13	Trans O&M Exp		439,642	435,533	185,335	102,122	145,684	2,297	94	4,109
14	Other O&M Adjustments		0	0	0	0	0	0	0	0
15	Distr Oper Exp		67,771	67,755	39,285	16,449	4,834	7,164	22	17
16	Distr Maint Exp		121,245	121,215	69,459	39,235	11,144	1,323	55	30
17	Total T&D Expense		628,658	624,502	294,078	157,807	161,662	10,784	171	4,156
18	Customer Related O&M									
19	Customer Accounts Exp		44,461	44,461	39,141	5,251	64	5	0	0
20	Customer Service Exp		8,693	8,634	4,397	1,525	2,672	37	3	60
21	Sales Expense		165	165	145	20	0	0	0	0
22	Total Customer Expense		53,320	53,260	43,683	6,796	2,737	42	3	60
23	Admin & General Expense		172,475	171,892	94,648	44,148	28,671	4,367	57	584
24	Total Electric O&M Expense		2,720,745	2,697,526	1,169,037	643,561	858,435	25,483	1,010	23,219

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Residential/Secondary
O&M Summary

	(a)	(b)	(c)	(d)	-	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Rate Residential	Rate RT	Total Residential		Rate GS	Rate GSD	Rate GS GEI	Rate GSD GEI	Commercial Secondary
1	Production									
2	Fuel Expense	196,060	-	196,060		61,058	55,100	1,477	3,109	120,744
3	Purchased & Interchange Power Expense	467,301	-	467,301		139,070	122,614	3,298	6,670	271,653
4	Total Fuel and P&I Expense	663,361	-	663,361		200,128	177,714	4,775	9,779	392,397
5	Fossil O&M Exp	46,293	-	46,293		13,810	12,346	327	672	27,155
6	Nuclear O&M Exp	0	-	0		0	0	0	0	0
7	Hydro O&M Exp	6,069	-	6,069		1,789	1,581	42	85	3,497
8	Peaker O&M Exp	16,573	-	16,573		4,808	4,181	113	222	9,325
9	Other O&M	4,332	-	4,332		1,257	1,093	29	58	2,437
10	Total Prod O&M Exp	73,266	-	73,266		21,664	19,201	512	1,038	42,414
11	Total Prod O&M Expense Including Fuel and P&I	736,627	-	736,627		221,792	196,915	5,287	10,817	434,811
12	Trans and Dist O&M									
13	Trans O&M Exp	185,335	-	185,335		52,330	45,698	1,317	2,777	102,122
14	Other O&M Adjustments	0	-	0		0	0	0	0	0
15	Distr Oper Exp	39,285	-	39,285		9,963	5,604	315	567	16,449
16	Distr Maint Exp	69,459	-	69,459		22,582	14,355	809	1,489	39,235
17	Total T&D Expense	294,078	-	294,078		84,875	65,657	2,441	4,833	157,807
18	Customer Related O&M									
19	Customer Accounts Exp	39,141	-	39,141		4,697	493	40	21	5,251
20	Customer Service Exp	4,397	-	4,397		882	584	19	41	1,525
21	Sales Expense	145	-	145		17	2	0	0	20
22	Total Customer Expense	43,683	-	43,683		5,596	1,079	59	61	6,796
23	Admin & General Expense	94,648	-	94,648		25,362	16,681	741	1,364	44,148
24	Total Electric O&M Expense	1,169,037	-	1,169,037		337,625	280,332	8,528	17,076	643,561

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1.1

Case No.: U-20134
Exhiit No.: A-16 (JCA-2)
Schedule: F-1.1
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Witness: JCAponte
Date: May 2018

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Primary & Lighting
O&M Summary

Line No.	(a) Description	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) Rate GU-XL	(o) Rate GU	(p) Lighting & Unmetered
1	Production															
2	Fuel Expense	19,103	51,851	35,476	83,508	2,929	5,748	656	836	3,954	204,062	218	1,757	0	1,458	3,433
3	Purchased & Interchange Power Expense	40,632	92,600	65,989	171,789	5,970	9,510	1,288	2,060	8,359	398,198	380	3,055	0	2,449	5,884
4	Total Fuel and P&I Expense	59,735	144,452	101,465	255,296	8,900	15,258	1,944	2,896	12,313	602,260	598	4,812	0	3,907	9,317
5	Fossil O&M Exp	4,124	10,261	7,176	17,861	612	1,082	137	201	854	42,308	45	365	0	277	688
6	Nuclear O&M Exp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Hydro O&M Exp	520	1,189	848	2,211	76	121	17	27	107	5,116	5	41	0	31	77
8	Peaker O&M Exp	1,347	2,690	1,984	5,570	192	257	40	74	276	12,431	11	87	0	67	165
9	Other O&M	352	703	519	1,456	50	67	11	19	72	3,249	3	23	0	18	43
10	Total Prod O&M Exp	6,343	14,843	10,527	27,097	931	1,528	205	322	1,309	63,105	64	515	0	393	972
11	Total Prod O&M Expense Including Fuel and P&I	66,078	159,295	111,992	282,394	9,831	16,786	2,149	3,218	13,623	665,365	662	5,327	0	4,301	10,290
12	Trans and Dist O&M															
13	Trans O&M Exp	14,750	35,351	24,943	63,773	2,447	-	461	720	3,239	145,684	153	1,231	0	912	2,297
14	Other O&M Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Distr Oper Exp	906	76	460	2,893	182	29	1	29	258	4,834	132	6,962	1	69	7,164
16	Distr Maint Exp	1,794	240	1,118	6,821	410	77	4	71	609	11,144	79	1,066	0	178	1,323
17	Total T&D Expense	17,450	35,666	26,521	73,487	3,039	106	466	820	4,107	161,662	364	9,259	1	1,159	10,784
18	Customer Related O&M															
19	Customer Accounts Exp	24	1	3	30	3	0	0	0	3	64	3	-	-	2	5
20	Customer Service Exp	200	712	574	1,001	33	60	7	20	64	2,672	3	19	0	15	37
21	Sales Expense	0	0	0	0	0	0	0	0	0	0	0	-	-	0	0
22	Total Customer Expense	225	713	576	1,032	36	60	7	21	67	2,737	6	19	0	17	42
23	Admin & General Expense	3,545	4,745	4,158	14,002	606	486	70	175	884	28,671	121	4,013	1	233	4,367
24	Total Electric O&M Expense	87,298	200,419	143,247	370,915	13,512	17,439	2,693	4,233	18,680	858,435	1,153	18,618	2	5,709	25,483

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Summary
Allocators 1

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
	Input Allocation Schedules									
1	Energy @ Generation	100	100.000	98.916	37.175	22.472	38.528	0.689	0.052	1.084
2	Energy On-Peak @ Generation	101	100.000	98.916	35.798	23.764	38.870	0.440	0.043	1.084
3	Energy Off-Peak @ Generation	102	100.000	98.916	38.781	20.967	38.129	0.978	0.061	1.084
4	Energy On-Peak @ Generation Summer	103	100.000	98.916	36.521	23.463	38.551	0.340	0.041	1.084
5	Energy Off-Peak @ Generation Summer	104	100.000	98.916	38.774	20.529	38.655	0.894	0.064	1.084
6	Energy On-Peak @ Generation Non-Summer	105	100.000	98.916	35.397	23.931	39.047	0.496	0.045	1.084
7	Energy Off-Peak @ Generation Non-Summer	106	100.000	98.916	38.784	21.200	37.848	1.023	0.060	1.084
8	Energy Critical On-Peak @ Gen	107	100.000	98.916	36.423	24.934	37.255	0.275	0.029	1.084
9	Energy Summer Mid-Peak @ Gen	108	100.000	98.916	36.547	23.072	38.896	0.357	0.044	1.084
10	12CP Dmd @ Generation	120	100.000	99.065	42.156	23.229	33.137	0.522	0.021	0.935
11	4CP Dmd @ Generation	121	100.000	99.144	43.147	24.254	31.548	0.173	0.021	0.856
12	Class Peak @ Subtransmission	122	100.000	99.939	44.221	26.315	28.419	0.650	0.335	0.061
13	Classpeak @ Transmission	127	100.000	99.204	39.756	23.658	34.904	0.584	0.301	0.796
14	Total Rate Revenue	143	100.000	99.413	45.993	25.211	27.128	1.032	0.048	0.587
15	Billed Sales	150	100.000	98.982	32.610	20.313	45.406	0.604	0.048	1.018
16	Billed Sales Excluding Rate E1	151	100.000	98.982	32.610	20.313	45.406	0.604	0.048	1.018
17	Number Of Customers	160	100.000	100.000	87.933	11.796	0.229	0.040	0.001	0.000
18	Weighted Customer	170	100.000	99.998	77.175	16.217	6.574	0.018	0.015	0.002
	Calculated Allocation Schedules									
19	4CP Average & Excess	219	100.000	99.138	42.669	24.008	32.006	0.424	0.031	0.862
20	4CP 75/0/25	220	100.000	99.144	41.678	23.822	33.312	0.302	0.029	0.856
21	4CP 75/0/25 Exc WFR	222	100.000	99.961	42.019	24.018	33.590	0.305	0.029	0.039
22	4CP Dmd @ Gen Jurisdictional	224	100.000	100.000	43.519	24.464	31.821	0.175	0.021	-
23	12CP Demand @ Subtrans	226	100.000	100.000	46.373	25.552	27.491	0.575	0.008	-
24	Classpeak @ Primary	230	100.000	100.000	48.213	28.691	22.380	0.708	0.008	-
25	Classpeak @ Secondary	231	100.000	100.000	62.120	36.967	-	0.913	-	-
26	Classpeak for Streetlighting	233	100.000	99.326	-	-	-	99.326	-	0.674
27	Classpeak @ Single Phase	235	100.000	100.000	62.120	36.967	-	0.913	-	-
28	Billed Sales ROA	252	100.000	100.000	-	5.847	94.153	-	-	-
29	Billed Sales - Primary	253	100.000	100.000	43.147	26.877	29.175	0.800	0.001	-
30	Customers - Residential	260	100.000	100.000	100.000	-	-	-	-	-
31	Customers - Drops	261	100.000	100.000	-	100.000	-	-	-	-
32	Customers - NonPID	263	100.000	100.000	88.159	11.826	-	0.015	-	-
33	Customers - NonMunicipal	264	100.000	100.000	87.969	11.801	0.229	-	0.001	0.000
34	PIS - 138kV Distribution	301	100.000	99.204	39.756	23.658	34.904	0.584	0.301	0.796
35	PIS - 46kV Distribution	302	100.000	99.939	44.221	26.315	28.419	0.650	0.335	0.061
36	PIS - 138kV Dist Subs S&E	303	100.000	99.204	39.756	23.658	34.904	0.584	0.301	0.796
37	PIS - 46kV Dist Subs S&E	304	100.000	99.939	44.221	26.315	28.419	0.650	0.335	0.061

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Version 2
4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Residential/Secondary
Allocators 1

	(a)		(b)	(c)	(d)	-	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Alloc	Rate Residential	Rate RT	Total Residential		Rate GS	Rate GSD	Rate GS GEI	Rate GSD GEI	Commercial Secondary
	Input Allocation Schedules										
1	Energy @ Generation	100	37.175	-	37.175		11.318	10.314	0.271	0.570	22.472
2	Energy On-Peak @ Generation	101	35.798	-	35.798		12.074	10.682	0.332	0.676	23.764
3	Energy Off-Peak @ Generation	102	38.781	-	38.781		10.436	9.884	0.199	0.448	20.967
4	Energy On-Peak @ Generation Summer	103	36.521	-	36.521		11.698	10.934	0.284	0.547	23.463
5	Energy Off-Peak @ Generation Summer	104	38.774	-	38.774		9.849	10.110	0.178	0.391	20.529
6	Energy On-Peak @ Generation Non-Summer	105	35.397	-	35.397		12.282	10.543	0.359	0.747	23.931
7	Energy Off-Peak @ Generation Non-Summer	106	38.784	-	38.784		10.750	9.764	0.209	0.478	21.200
8	Energy Critical On-Peak @ Gen	107	36.423	-	36.423		12.867	11.235	0.272	0.559	24.934
9	Energy Summer Mid-Peak @ Gen	108	36.547	-	36.547		11.387	10.853	0.287	0.544	23.072
10	12CP Dmd @ Generation	120	42.156	-	42.156		11.903	10.394	0.300	0.632	23.229
11	4CP Dmd @ Generation	121	43.147	-	43.147		12.510	10.873	0.293	0.578	24.254
12	Class Peak @ Subtransmission	122	44.221	-	44.221		13.636	10.913	0.605	1.162	26.315
13	Classpeak @ Transmission	127	39.756	-	39.756		12.259	9.811	0.544	1.045	23.658
14	Total Rate Revenue	143	45.993	-	45.993		13.265	10.934	0.313	0.698	25.211
15	Billed Sales	150	32.610	-	32.610		9.946	9.422	0.278	0.668	20.313
16	Billed Sales Excluding Rate E1	151	32.610	-	32.610		9.946	9.422	0.278	0.668	20.313
17	Number Of Customers	160	87.933	-	87.933		10.553	1.108	0.090	0.046	11.796
18	Weighted Customer	170	77.175	-	77.175		13.876	2.134	0.118	0.089	16.217
	Calculated Allocation Schedules										
19	4CP Average & Excess	219	42.669	-	42.669		12.380	10.766	0.290	0.573	24.008
20	4CP 75/0/25	220	41.678	-	41.678		12.219	10.739	0.288	0.576	23.822
21	4CP 75/0/25 Exc WFR	222	42.019	-	42.019		12.320	10.827	0.290	0.581	24.018
22	4CP Dmd @ Gen Jurisdictional	224	43.519	-	43.519		12.619	10.966	0.296	0.583	24.464
23	12CP Demand @ Subtrans	226	46.373	-	46.373		13.094	11.434	0.330	0.695	25.552
24	Classpeak @ Primary	230	48.213	-	48.213		14.867	11.898	0.660	1.267	28.691
25	Classpeak @ Secondary	231	62.120	-	62.120		19.155	15.330	0.850	1.632	36.967
26	Classpeak for Streetlighting	233	-	-	-		-	-	-	-	-
27	Classpeak @ Single Phase	235	62.120	-	62.120		19.155	15.330	0.850	1.632	36.967
28	Billed Sales ROA	252	-	-	-		0.174	3.643	0.395	1.634	5.847
29	Billed Sales - Primary	253	43.147	-	43.147		13.159	12.466	0.368	0.884	26.877
30	Customers - Residential	260	100.000	-	100.000		-	-	-	-	-
31	Customers - Drops	261	-	-	-		89.458	9.391	0.760	0.391	100.000
32	Customers - NonPID	263	88.159	-	88.159		10.580	1.111	0.090	0.046	11.826
33	Customers - NonMunicipal	264	87.969	-	87.969		10.557	1.108	0.090	0.046	11.801
34	PIS - 138kV Distribution	301	39.756	-	39.756		12.259	9.811	0.544	1.045	23.658
35	PIS - 46kV Distribution	302	44.221	-	44.221		13.636	10.913	0.605	1.162	26.315
36	PIS - 138kV Dist Subs S&E	303	39.756	-	39.756		12.259	9.811	0.544	1.045	23.658
37	PIS - 46kV Dist Subs S&E	304	44.221	-	44.221		13.636	10.913	0.605	1.162	26.315

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4CP Average & Excess Production and 12CP Transmission
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Primary & Lighting
Allocators 1

Line No.	(a) Description	Alloc	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) Rate GU-XL	(o) Rate GU	(p) Lighting & Unmetered
	Input Allocation Schedules																
1	Energy @ Generation	100	3.528	9.889	6.743	15.725	0.537	1.088	0.125	0.158	0.735	38.528	0.046	0.367	0.000	0.276	0.689
2	Energy On-Peak @ Generation	101	4.106	9.471	6.548	15.881	0.653	1.128	0.118	0.158	0.806	38.870	0.022	0.174	0.000	0.245	0.440
3	Energy Off-Peak @ Generation	102	2.855	10.376	6.969	15.543	0.402	1.041	0.133	0.157	0.653	38.129	0.074	0.592	0.000	0.313	0.978
4	Energy On-Peak @ Generation Summer	103	4.130	9.006	6.466	16.289	0.539	1.059	0.118	0.177	0.767	38.551	0.012	0.097	0.000	0.231	0.340
5	Energy Off-Peak @ Generation Summer	104	2.909	10.121	7.046	16.229	0.346	1.032	0.137	0.190	0.645	38.655	0.066	0.531	0.000	0.298	0.894
6	Energy On-Peak @ Generation Non-Summer	105	4.093	9.729	6.594	15.655	0.716	1.167	0.118	0.148	0.828	39.047	0.027	0.216	0.000	0.253	0.496
7	Energy Off-Peak @ Generation Non-Summer	106	2.826	10.512	6.928	15.176	0.432	1.047	0.131	0.140	0.657	37.848	0.078	0.625	0.000	0.321	1.023
8	Energy Critical On-Peak @ Gen	107	3.981	8.335	6.141	16.290	0.523	0.923	0.115	0.178	0.770	37.255	-	-	-	0.275	0.275
9	Energy Summer Mid-Peak @ Gen	108	4.170	9.184	6.552	16.289	0.544	1.095	0.119	0.177	0.766	38.896	0.015	0.123	0.000	0.219	0.357
10	12CP Dmd @ Generation	120	3.355	8.041	5.674	14.506	0.557	-	0.105	0.164	0.737	33.137	0.035	0.280	0.000	0.208	0.522
11	4CP Dmd @ Generation	121	3.500	6.947	5.133	14.454	0.499	-	0.105	0.194	0.717	31.548	-	-	-	0.173	0.173
12	Class Peak @ Subtransmission	122	3.717	-	7.118	14.617	0.872	0.332	-	0.455	1.307	28.419	0.056	0.453	0.000	0.141	0.650
13	Classpeak @ Transmission	127	3.342	8.466	6.400	13.142	0.784	1.061	0.126	0.409	1.175	34.904	0.051	0.407	0.000	0.127	0.584
14	Total Rate Revenue	143	3.393	5.159	4.314	12.327	0.524	0.523	0.049	0.132	0.707	27.128	0.042	0.791	0.000	0.199	1.032
15	Billed Sales	150	3.367	12.137	9.766	17.003	0.558	1.022	0.125	0.347	1.081	45.406	0.040	0.322	0.000	0.242	0.604
16	Billed Sales Excluding Rate E1	151	3.367	12.137	9.766	17.003	0.558	1.022	0.125	0.347	1.081	45.406	0.040	0.322	0.000	0.242	0.604
17	Number Of Customers	160	0.087	0.003	0.009	0.109	0.010	0.001	0.000	0.000	0.010	0.229	0.015	-	-	0.026	0.040
18	Weighted Customer	170	2.422	0.075	0.265	3.181	0.288	0.030	0.004	0.014	0.293	6.574	0.018	-	-	-	0.018
	Calculated Allocation Schedules																
19	4CP Average & Excess	219	3.468	6.925	5.109	14.341	0.495	0.662	0.104	0.191	0.711	32.006	0.028	0.223	0.000	0.173	0.424
20	4CP 75/0/25	220	3.509	7.687	5.538	14.780	0.509	0.272	0.110	0.185	0.722	33.312	0.011	0.092	0.000	0.199	0.302
21	4CP 75/0/25 Exc WFR	222	3.538	7.752	5.585	14.903	0.513	0.275	0.111	0.186	0.728	33.590	0.012	0.093	0.000	0.201	0.305
22	4CP Dmd @ Gen Jurisdictional	224	3.530	7.007	5.177	14.579	0.503	-	0.106	0.195	0.723	31.821	-	-	-	0.175	0.175
23	12CP Demand @ Subtrans	226	3.691	-	6.241	15.957	0.612	-	-	0.180	0.810	27.491	0.038	0.308	0.000	0.228	0.575
24	Classpeak @ Primary	230	4.053	-	-	15.937	0.950	0.015	-	-	1.425	22.380	0.061	0.493	0.000	0.154	0.708
25	Classpeak @ Secondary	231	-	-	-	-	-	-	-	-	-	-	0.079	0.636	0.000	0.198	0.913
26	Classpeak for Streetlighting	233	-	-	-	-	-	-	-	-	-	-	10.975	88.346	0.004	-	99.326
27	Classpeak @ Single Phase	235	-	-	-	-	-	-	-	-	-	-	0.079	0.636	0.000	0.198	0.913
28	Billed Sales ROA	252	1.207	27.346	34.198	24.804	0.625	-	0.074	1.953	3.946	94.153	-	-	-	-	-
29	Billed Sales - Primary	253	4.455	-	-	22.496	0.738	0.055	-	-	1.431	29.175	0.053	0.426	0.000	0.321	0.800
30	Customers - Residential	260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Drops	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Customers - NonPID	263	-	-	-	-	-	-	-	-	-	-	0.015	-	-	-	0.015
33	Customers - NonMunicipal	264	0.087	0.003	0.009	0.109	0.010	0.001	0.000	0.000	0.010	0.229	-	-	-	-	-
34	PIS - 138kV Distribution	301	3.342	8.466	6.400	13.142	0.784	1.061	0.126	0.409	1.175	34.904	0.051	0.407	0.000	0.127	0.584
35	PIS - 46kV Distribution	302	3.717	-	7.118	14.617	0.872	0.332	-	0.455	1.307	28.419	0.056	0.453	0.000	0.141	0.650
36	PIS - 138kV Dist Subs S&E	303	3.342	8.466	6.400	13.142	0.784	1.061	0.126	0.409	1.175	34.904	0.051	0.407	0.000	0.127	0.584
37	PIS - 46kV Dist Subs S&E	304	3.717	-	7.118	14.617	0.872	0.332	-	0.455	1.307	28.419	0.056	0.453	0.000	0.141	0.650

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4CP Average & Excess Production and 12CP Transmission
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Summary
Allocators 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Alloc	Total Electric	Total Jurisdictional Electric	Total Residential	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
	Calculated Allocation Schedules									
1	PIS - Overhead Primary System	305	100.000	100.000	62.120	36.967	-	0.913	-	(0.000)
2	PIS - Distribution Distribution	306	100.000	99.998	60.027	32.315	5.069	2.584	0.003	0.002
3	Overhead Distribution	307	100.000	99.985	58.112	33.452	7.705	0.674	0.042	0.015
4	Underground Distribution	308	100.000	100.000	61.000	36.300	1.803	0.896	0.001	(0.000)
5	Total Dist PIS	309	100.000	99.932	56.546	30.924	10.203	2.193	0.067	0.068
6	Distribution Services	310	100.000	100.000	66.547	33.453	-	-	-	-
7	Streetlighting Equipment	311	100.000	99.908	-	-	-	99.908	-	0.092
8	Line Equipment	312	100.000	100.000	60.363	35.921	2.828	0.887	0.001	-
9	Meters	313	100.000	99.998	77.176	16.217	6.574	0.018	0.015	0.002
10	PIS - System Power Control	314	100.000	199.143	83.977	49.973	63.323	1.234	0.635	(99.143)
11	PIS - General	315	100.000	99.628	54.651	25.061	17.614	2.267	0.035	0.372
12	Total PIS	316	100.000	99.605	51.123	27.785	19.115	1.530	0.051	0.395
13	Distribution Depreciation	317	100.000	99.955	56.399	32.431	7.342	3.710	0.072	0.045
14	CWIP	330	100.000	99.443	48.018	25.738	24.469	1.165	0.054	0.557
15	Working Capital	340	100.000	99.502	51.452	23.924	22.118	1.972	0.035	0.498
16	Rate Base	390	100.000	99.587	51.042	27.096	20.273	1.128	0.049	0.413
17	Operations - Distribution excl Sup & Eng	400	100.000	99.980	58.596	24.187	6.152	11.025	0.020	0.020
18	Maintenance - Distribution excl Sup & Eng	401	100.000	99.988	57.934	32.669	8.240	1.112	0.033	0.012
19	Operations - 138kV Distribution excl Sup & Eng	402	100.000	99.144	43.147	24.254	31.548	0.173	0.021	0.856
20	Maintenance - 138kV Distribution excl Sup & Eng	403	100.000	99.254	39.995	23.709	34.709	0.558	0.283	0.746
21	Operations - 46kV Distribution excl Sup & Eng	404	100.000	99.939	44.221	26.315	28.419	0.650	0.335	0.061
22	Maintenance - 46kV Distribution excl Sup & Eng	405	100.000	99.939	44.221	26.315	28.419	0.650	0.335	0.061
23	HV Distribution O&M exp.	406	100.000	99.755	43.206	25.644	29.979	0.613	0.313	0.245
24	Distribution O&M, excl. HV Dist	407	100.000	99.986	58.190	29.616	7.461	4.692	0.028	0.014
25	Customer Accounting	408	100.000	100.000	88.033	11.810	0.145	0.012	0.000	0.000
26	Customer Accounts & Service	409	100.000	99.888	81.908	12.748	5.148	0.079	0.006	0.112
27	Distribution O&M	410	100.000	99.975	57.531	29.460	8.453	4.490	0.041	0.025
28	Customer & Sales O&M	411	100.000	99.888	81.926	12.745	5.132	0.079	0.006	0.112
29	Administrative and General O&M	412	100.000	99.662	54.876	25.597	16.623	2.532	0.033	0.338
30	Jurisdictional Distribution O&M	414	100.000	100.000	57.545	29.467	8.455	4.491	0.041	-
31	O&M Excluding Adjustments	438	100.000	99.147	42.968	23.654	31.551	0.937	0.037	0.853
32	Pre Tax NOI	439	100.000	100.208	51.305	28.851	18.938	0.824	0.290	(0.208)
33	R&PP Tax	440	100.000	99.626	50.847	27.692	19.550	1.478	0.059	0.374
34	Depreciation & Amortization Expense	442	100.000	99.531	51.137	26.962	19.875	1.514	0.043	0.469
35	Non PSCR O&M Expense	443	100.000	99.593	53.714	24.991	18.527	2.326	0.035	0.407
36	Distribution Depreciation Expense	444	100.000	99.951	59.529	31.322	6.584	2.456	0.060	0.049
37	Gen/Comm/Int Depreciation Expense	445	100.000	99.628	54.651	25.061	17.614	2.267	0.035	0.372
38	Production Labor	500	100.000	99.138	42.669	24.008	32.006	0.424	0.031	0.862
39	Total Labor	502	100.000	99.628	54.651	25.061	17.614	2.267	0.035	0.372
40	50% O&M, 50% Net Plant	600	100.000	99.500	49.310	26.576	22.528	1.039	0.047	0.500
41	50/50 PIS & Labor	601	100.000	99.616	52.887	26.423	18.365	1.898	0.043	0.384

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Residential/Secondary
Allocators 2

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Alloc	Rate Residential	Rate RT	Total Residential	Rate GS	Rate GSD	Rate GS GEI	Rate GSD GEI	Commercial Secondary
	Calculated Allocation Schedules									
1	PIS - Overhead Primary System	305	62.120	-	62.120	19.155	15.330	0.850	1.632	36.967
2	PIS - Distribution Distribution	306	60.027	-	60.027	18.756	11.693	0.658	1.208	32.315
3	Overhead Distribution	307	58.112	-	58.112	19.647	11.900	0.675	1.230	33.452
4	Underground Distribution	308	61.000	-	61.000	18.809	15.053	0.835	1.603	36.300
5	Total Dist PIS	309	56.546	-	56.546	17.634	11.457	0.643	1.190	30.924
6	Distribution Services	310	66.547	-	66.547	29.927	3.142	0.254	0.131	33.453
7	Streetlighting Equipment	311	-	-	-	-	-	-	-	-
8	Line Equipment	312	60.363	-	60.363	18.613	14.896	0.826	1.586	35.921
9	Meters	313	77.176	-	77.176	13.876	2.134	0.118	0.089	16.217
10	PIS - System Power Control	314	83.977	-	83.977	25.894	20.723	1.149	2.206	49.973
11	PIS - General	315	54.651	-	54.651	14.371	9.525	0.410	0.755	25.061
12	Total PIS	316	51.123	-	51.123	15.355	11.024	0.489	0.918	27.785
13	Distribution Depreciation	317	56.399	-	56.399	18.775	11.771	0.665	1.221	32.431
14	CWIP	330	48.018	-	48.018	13.907	10.670	0.400	0.761	25.738
15	Working Capital	340	51.452	-	51.452	13.382	9.545	0.336	0.662	23.924
16	Rate Base	390	51.042	-	51.042	14.884	10.850	0.471	0.890	27.096
17	Operations - Distribution excl Sup & Eng	400	58.596	-	58.596	14.754	8.149	0.460	0.824	24.187
18	Maintenance - Distribution excl Sup & Eng	401	57.934	-	57.934	18.868	11.897	0.671	1.234	32.669
19	Operations - 138kV Distribution excl Sup & Eng	402	43.147	-	43.147	12.510	10.873	0.293	0.578	24.254
20	Maintenance - 138kV Distribution excl Sup & Eng	403	39.995	-	39.995	12.282	9.884	0.528	1.015	23.709
21	Operations - 46kV Distribution excl Sup & Eng	404	44.221	-	44.221	13.636	10.913	0.605	1.162	26.315
22	Maintenance - 46kV Distribution excl Sup & Eng	405	44.221	-	44.221	13.636	10.913	0.605	1.162	26.315
23	HV Distribution O&M exp.	406	43.206	-	43.206	13.285	10.673	0.577	1.109	25.644
24	Distribution O&M, excl. HV Dist	407	58.190	-	58.190	17.391	10.544	0.595	1.086	29.616
25	Customer Accounting	408	88.033	-	88.033	10.565	1.109	0.090	0.046	11.810
26	Customer Accounts & Service	409	81.908	-	81.908	10.496	2.027	0.111	0.115	12.748
27	Distribution O&M	410	57.531	-	57.531	17.218	10.559	0.595	1.088	29.460
28	Customer & Sales O&M	411	81.926	-	81.926	10.496	2.024	0.110	0.115	12.745
29	Administrative and General O&M	412	54.876	-	54.876	14.705	9.672	0.429	0.791	25.597
30	Jurisdictional Distribution O&M	414	57.545	-	57.545	17.223	10.562	0.595	1.088	29.467
31	O&M Excluding Adjustments	438	42.968	-	42.968	12.409	10.304	0.313	0.628	23.654
32	Pre Tax NOI	439	51.305	-	51.305	14.545	13.335	0.174	0.798	28.851
33	R&PP Tax	440	50.847	-	50.847	15.250	11.039	0.487	0.916	27.692
34	Depreciation & Amortization Expense	442	51.137	-	51.137	14.947	10.746	0.441	0.828	26.962
35	Non PSCR O&M Expense	443	53.714	-	53.714	14.281	9.544	0.408	0.758	24.991
36	Distribution Depreciation Expense	444	59.529	-	59.529	18.242	11.283	0.634	1.163	31.322
37	Gen/Comm/Int Depreciation Expense	445	54.651	-	54.651	14.371	9.525	0.410	0.755	25.061
38	Production Labor	500	42.669	-	42.669	12.380	10.766	0.290	0.573	24.008
39	Total Labor	502	54.651	-	54.651	14.371	9.525	0.410	0.755	25.061
40	50% O&M, 50% Net Plant	600	49.310		49.310	14.461	10.818	0.447	0.850	26.576
41	50/50 PIS & Labor	601	52.887		52.887	14.863	10.274	0.449	0.836	26.423

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4CP Average & Excess Production and 12CP Transmission
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Primary & Lighting
Allocators 2

Line No.	(a) Description	Alloc	(b) Rate GP	(c) Rate GPD Vlt 1	(d) Rate GPD Vlt 2	(e) Rate GPD Vlt 3	(f) Rate GP GEI	(g) Rate EIP	(h) Rate GPD GEI Vlt 1	(i) Rate GPD GEI Vlt 2	(j) Rate GPD GEI Vlt 3	(k) Total Primary	(l) Rate GML	(m) Rate GUL	(n) Rate GU-XL	(o) Rate GU	(p) Lighting & Unmetered
	Calculated Allocation Schedules																
1	PIS - Overhead Primary System	305	-	-	-	-	-	-	-	-	-	-	0.079	0.636	0.000	0.198	0.913
2	PIS - Distribution Distribution	306	1.028	0.007	0.027	3.472	0.216	0.006	0.000	0.001	0.311	5.069	0.086	2.354	0.000	0.144	2.584
3	Overhead Distribution	307	1.206	0.090	0.855	4.741	0.283	0.051	0.001	0.055	0.424	7.705	0.058	0.470	0.000	0.146	0.674
4	Underground Distribution	308	0.327	-	-	1.284	0.077	0.001	-	-	0.115	1.803	0.078	0.624	0.000	0.195	0.896
5	Total Dist PIS	309	1.537	0.626	1.389	5.588	0.340	0.124	0.010	0.089	0.500	10.203	0.080	1.971	0.000	0.142	2.193
6	Distribution Services	310	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Streetlighting Equipment	311	-	-	-	-	-	-	-	-	-	-	1.497	98.398	0.014	-	99.908
8	Line Equipment	312	0.512	-	-	2.014	0.120	0.002	-	-	0.180	2.828	0.077	0.618	0.000	0.193	0.887
9	Meters	313	2.422	0.075	0.265	3.181	0.288	0.030	0.004	0.014	0.293	6.574	0.018	-	-	-	0.018
10	PIS - System Power Control	314	7.059	8.466	13.518	27.759	1.655	1.393	0.126	0.865	2.482	63.323	0.107	0.859	0.000	0.268	1.234
11	PIS - General	315	2.131	3.034	2.627	8.478	0.359	0.309	0.045	0.110	0.523	17.614	0.065	2.067	0.000	0.135	2.267
12	Total PIS	316	2.321	3.225	2.907	9.158	0.401	0.344	0.048	0.129	0.582	19.115	0.059	1.318	0.000	0.153	1.530
13	Distribution Depreciation	317	0.964	0.335	1.526	3.752	0.224	0.102	0.005	0.098	0.335	7.342	0.101	3.464	0.000	0.146	3.710
14	CWIP	330	2.827	4.437	3.964	11.435	0.455	0.457	0.067	0.167	0.660	24.469	0.047	0.960	0.000	0.158	1.165
15	Working Capital	340	2.617	4.273	3.456	10.171	0.416	0.436	0.052	0.114	0.584	22.118	0.057	1.752	0.000	0.162	1.972
16	Rate Base	390	2.515	3.408	2.945	9.801	0.436	0.360	0.050	0.128	0.631	20.273	0.052	0.922	0.000	0.153	1.128
17	Operations - Distribution excl Sup & Eng	400	1.229	0.089	0.394	3.799	0.243	0.031	0.002	0.025	0.341	6.152	0.202	10.722	0.001	0.100	11.025
18	Maintenance - Distribution excl Sup & Eng	401	1.387	0.071	0.661	5.251	0.316	0.041	0.001	0.042	0.470	8.240	0.066	0.899	0.000	0.147	1.112
19	Operations - 138kV Distribution excl Sup & Eng	402	3.500	6.947	5.133	14.454	0.499	0.000	0.105	0.194	0.717	31.548	0.000	0.000	0.000	0.173	0.173
20	Maintenance - 138kV Distribution excl Sup & Eng	403	3.354	8.374	6.322	13.233	0.766	0.994	0.125	0.396	1.146	34.709	0.047	0.381	0.000	0.130	0.558
21	Operations - 46kV Distribution excl Sup & Eng	404	3.717	-	7.118	14.617	0.872	0.332	-	0.455	1.307	28.419	0.056	0.453	0.000	0.141	0.650
22	Maintenance - 46kV Distribution excl Sup & Eng	405	3.717	-	7.118	14.617	0.872	0.332	-	0.455	1.307	28.419	0.056	0.453	0.000	0.141	0.650
23	HV Distribution O&M exp.	406	3.626	2.166	6.870	14.291	0.835	0.475	0.032	0.433	1.251	29.979	0.052	0.421	0.000	0.139	0.613
24	Distribution O&M, excl. HV Dist	407	1.328	0.071	0.556	4.721	0.289	0.036	0.001	0.035	0.423	7.461	0.115	4.446	0.001	0.130	4.692
25	Customer Accounting	408	0.055	0.002	0.006	0.069	0.007	0.001	0.000	0.000	0.006	0.145	0.008	-	-	0.004	0.012
26	Customer Accounts & Service	409	0.422	1.342	1.084	1.941	0.068	0.113	0.014	0.039	0.125	5.148	0.012	0.036	0.000	0.031	0.079
27	Distribution O&M	410	1.428	0.167	0.835	5.140	0.313	0.056	0.003	0.053	0.459	8.453	0.112	4.247	0.001	0.131	4.490
28	Customer & Sales O&M	411	0.421	1.338	1.080	1.935	0.067	0.113	0.014	0.038	0.125	5.132	0.012	0.035	0.000	0.031	0.079
29	Administrative and General O&M	412	2.055	2.751	2.411	8.119	0.351	0.282	0.041	0.101	0.513	16.623	0.070	2.327	0.000	0.135	2.532
30	Jurisdictional Distribution O&M	414	1.429	0.167	0.835	5.141	0.313	0.056	0.003	0.053	0.459	8.455	0.112	4.248	0.001	0.131	4.491
31	O&M Excluding Adjustments	438	3.209	7.366	5.265	13.633	0.497	0.641	0.099	0.156	0.687	31.551	0.042	0.684	0.000	0.210	0.937
32	Pre Tax NOI	439	5.129	(1.097)	2.039	10.968	0.775	0.253	(0.128)	0.045	0.953	18.938	0.023	0.597	(0.000)	0.203	0.824
33	R&PP Tax	440	2.410	2.944	3.122	9.530	0.420	0.327	0.044	0.142	0.611	19.550	0.058	1.266	0.000	0.154	1.478
34	Depreciation & Amortization Expense	442	2.302	3.790	3.219	9.107	0.361	0.387	0.057	0.135	0.518	19.875	0.055	1.306	0.000	0.153	1.514
35	Non PSCR O&M Expense	443	2.148	3.457	2.823	8.694	0.363	0.366	0.048	0.103	0.524	18.527	0.067	2.109	0.000	0.149	2.326
36	Distribution Depreciation Expense	444	1.003	0.432	1.258	3.213	0.203	0.099	0.007	0.080	0.288	6.584	0.083	2.235	0.000	0.138	2.456
37	Gen/Comm/Int Depreciation Expense	445	2.131	3.034	2.627	8.478	0.359	0.309	0.045	0.110	0.523	17.614	0.065	2.067	0.000	0.135	2.267
38	Production Labor	500	3.468	6.925	5.109	14.341	0.495	0.662	0.104	0.191	0.711	32.006	0.028	0.223	0.000	0.173	0.424
39	Total Labor	502	2.131	3.034	2.627	8.478	0.359	0.309	0.045	0.110	0.523	17.614	0.065	2.067	0.000	0.135	2.267
40	50% O&M, 50% Net Plant	600	2.652	4.189	3.403	10.580	0.450	0.414	0.061	0.134	0.645	22.528	0.050	0.823	0.000	0.165	1.039
41	50/50 PIS & Labor	601	2.226	3.129	2.767	8.818	0.380	0.326	0.047	0.120	0.552	18.365	0.062	1.693	0.000	0.144	1.898

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4CP Average & Excess Production and 12CP Transmission
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Net Plant

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	Plant in Service									
2	Production		5,808,691	5,758,619	2,478,519	1,394,548	1,859,113	24,615	1,825	50,072
3	Transmission		0	0	0	0	0	0	0	0
4	Distribution		8,171,969	8,166,446	4,620,933	2,527,067	833,767	179,217	5,462	5,523
5	General/Common/Intangible		1,359,164	1,354,106	742,798	340,618	239,402	30,815	474	5,058
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0
7	Total Plant in Service		15,339,824	15,279,172	7,842,250	4,262,233	2,932,282	234,646	7,761	60,652
8	Depreciation Reserve									
9	Production		2,211,253	2,192,192	943,523	530,877	707,727	9,370	695	19,061
10	Transmission		0	0	0	0	0	0	0	0
11	Distribution		2,901,832	2,900,527	1,636,616	941,102	213,046	107,671	2,092	1,305
12	General/Common/Intangible		749,513	746,724	409,617	187,834	132,019	16,993	261	2,789
13	Total Depreciation Reserve		5,862,598	5,839,443	2,989,756	1,659,813	1,052,792	134,034	3,048	23,155
14	Construction Work In Progress (CWIP)									
15	Production		267,902	265,593	114,312	64,318	85,744	1,135	84	2,309
16	Transmission		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
17	Distribution		118,703	118,676	64,687	35,866	15,718	2,263	141	27
18	General/Common/Intangible		100,146	99,773	54,731	25,097	17,640	2,270	35	373
19	Total CWIP		486,751	484,042	233,729	125,282	119,101	5,669	261	2,709
20	Future Use									
21	Production	219	1,741	1,726	743	418	557	7	1	15
22	Distribution	127	3,535	3,507	1,406	836	1,234	21	11	28
23	Common/General	231	0	0	0	0	-	0	-	-
24	PHFFU Depreciation Reserve	127	0	0	0	0	0	0	0	0
25	Total Future Use		5,277	5,234	2,149	1,254	1,791	28	11	43
26	Net Plant		9,969,253	9,929,005	5,088,372	2,728,957	2,000,382	106,309	4,985	40,249

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4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

PIS Summary

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production									
2	Production Plant in Service		5,808,691	5,758,619	2,478,519	1,394,548	1,859,113	24,615	1,825	50,072
3	Generation Step Ups		0	0	0	0	0	0	0	0
4	Total Production		5,808,691	5,758,619	2,478,519	1,394,548	1,859,113	24,615	1,825	50,072
5	Transmission									
6	Bulk Power Transm		0	0	0	0	0	0	0	0
7	Transm; Subtrans		0	0	0	0	0	0	0	0
8	Subtransmission		0	0	0	0	0	0	0	0
9	Total Transmission		0	0	0	0	0	0	0	0
10	Distribution									
11	Stations and Equipment		2,400,539	2,395,793	1,207,910	718,518	448,123	17,704	3,537	4,746
12	Overhead System		3,489,456	3,488,806	1,961,548	1,167,282	329,367	28,824	1,785	650
13	Underground System		784,489	784,481	476,275	283,423	17,734	6,999	50	8
14	Meters and Svc Drops		1,378,944	1,378,935	975,200	357,845	38,542	7,257	89	9
15	St Lgts and OPL		118,542	118,433	-	-	-	118,433	-	109
16	Total Distribution		8,171,969	8,166,446	4,620,933	2,527,067	833,767	179,217	5,462	5,523
17	General/Common/Intangible									
18	Total Gen/Comm/Int Plant		1,359,164	1,354,106	742,798	340,618	239,402	30,815	474	5,058
19	Plant Purchased/Sold		0	0	0	0	0	0	0	0
20	Total Plant in Service		15,339,824	15,279,172	7,842,250	4,262,233	2,932,282	234,646	7,761	60,652

Projected 12-Month Period Ending Dec 31, 2019
Version 2
4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Plant In Service (production & tran)

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	Production Plant									
2	Fossil	219	4,262,479	4,225,736	1,818,764	1,023,334	1,364,237	18,062	1,339	36,743
3	Nuclear	219	0	0	0	0	0	0	0	0
4	Total Hydro	219	546,303	541,594	233,103	131,156	174,848	2,315	172	4,709
5	Other Production/Combustion Turbine	219	999,909	991,290	426,653	240,058	320,028	4,237	314	8,619
6	7 Classics	219	0	0	0	0	0	0	0	0
7	Jackson Gas Plant	219	0	0	0	0	0	0	0	0
6	Distribution GSUs	219	0	0	0	0	0	0	0	0
7	Total Production		5,808,691	5,758,619	2,478,519	1,394,548	1,859,113	24,615	1,825	50,072
8	Transmission Plant									
9	Transmission Direct	228	0	0	0	0	0	0	0	0
10	Subtransmission	228	0	0	0	0	0	0	0	0
11	Transmission	127	0	0	0	0	0	0	0	0
12	Total		0	0	0	0	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1.1

Case No.: U-20134
Exhibit No.: A-16 (JCA-2)
Schedule: F-1.1

Witness: JCAponte
Date: May 2018

Projected 12-Month Period Ending Dec 31, 2019
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4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Plant In Service (distribution)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Plant									
2	345/138kV Substations/Overheads (METC) Land & ROW	127	89,200	88,490	35,463	21,103	31,135	521	268	710
3	345/138kV Substations/Overheads Land & ROW	127	26,832	26,618	10,667	6,348	9,365	157	81	214
4	46/23kV Substations/Overheads Land & ROW	124	48,795	48,765	21,577	12,840	13,867	317	163	30
5	Distribution Substation Land & ROW	230	7,812	7,812	3,766	2,241	1,748	55	1	-
6	138kV Substations/Overheads (Assignable) Land & ROW	DIR	0	-	-	-	-	-	-	-
7	46kV Substations/Overheads (Assignable) Land & ROW	DIR	0	-	-	-	-	-	-	-
8	Overhead Lines Land & ROW	307	25,419	25,415	14,772	8,503	1,958	171	11	4
9	Total		198,057	197,100	86,245	51,036	58,074	1,222	524	958
10	Distribution Substations & Equipment								-	-
11	138kV Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
12	46kV Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
13	138kV HV Subtran/Dist Substations	127	437,686	434,201	174,007	103,548	152,772	2,557	1,317	3,485
14	138kV HV Subtran/Dist Substations	127	0	0	0	0	0	0	0	0
15	46kV Subtran/Dist Substations	124	496,363	496,060	219,496	130,618	141,060	3,225	1,661	303
16	Distribution Substations	230	308,662	308,662	148,814	88,557	69,078	2,187	26	-
17	Total		1,242,711	1,238,923	542,317	322,723	362,909	7,969	3,004	3,788
18	Distribution Overhead System									
19	138kV HV Subtran/Dist Overhead Lines	127	45,400	45,038	18,049	10,741	15,846	265	137	362
20	138kV HV Subtran/Dist Overhead Lines	121	0	0	0	0	0	0	0	0
21	46kV Subtran Overheads & Transformer Platforms	122	472,514	472,225	208,950	124,342	134,282	3,070	1,581	288
22	Transformer Platforms	231	3,921	3,921	2,436	1,450	-	36	-	-
23	Three Phase Primary	230	800,898	800,898	386,136	229,782	179,239	5,674	67	-
24	Single Phase Primary	235	655,281	655,281	407,063	242,236	-	5,982	-	-
25	Single Phase Secondary	231	1,511,442	1,511,442	938,914	558,731	-	13,797	-	-
26	Total		3,489,456	3,488,806	1,961,548	1,167,282	329,367	28,824	1,785	650
27	Distribution Underground System									-
28	Three Phase Primary	230	62,124	62,124	29,952	17,824	13,903	440	5	-
29	Single Phase Primary	235	570,877	570,877	354,632	211,035	-	5,211	-	-
30	Single Phase Secondary	231	138,006	138,006	85,730	51,016	-	1,260	-	-
31	46kV Subtran/Distribution Underground Lines	122	13,482	13,473	5,962	3,548	3,831	88	45	8
32	Total		784,489	784,481	476,275	283,423	17,734	6,999	50	8
33	Distribution Line Equipment									-
34	Primary	230	121,272	121,272	58,469	34,794	27,140	859	10	-
35	Secondary	231	838,498	838,498	520,879	309,966	-	7,654	-	-
36	Total		959,770	959,770	579,347	344,759	27,140	8,513	10	-
37	Distribution Services									
38	Residential Overhead & Burial Services	260	522,704	522,704	522,704	-	-	-	-	-
39	C&I Overhead & Burial Services	261	262,763	262,763	-	262,763	-	-	-	-
40	Total		785,467	785,467	522,704	262,763	-	-	-	-

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Plant In Service (distribution & general)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Metering Equipment									
2	Metering Equipment (Mass)	170	586,322	586,313	452,497	95,082	38,542	103	89	9
3	Total		586,322	586,313	452,497	95,082	38,542	103	89	9
4	Distribution Installations on Customer Premises									
5	Installations on Premises L4 (Assignable)	DIR	7,155	7,155	-	-	-	7,155	-	-
6	Total		7,155	7,155	-	-	-	7,155	-	-
7	Distribution Streetlighting Equipment									
8	Luminaires/Suspensions/Poles/Transformers	DIR	102,376	102,376	-	-	-	102,376	-	-
9	Underground Cable & Conduits	233	9,154	9,092	-	-	-	9,092	-	62
10	Photoelectric Switches	233	7,012	6,965	-	-	-	6,965	-	47
11	Total		118,542	118,433	-	-	-	118,433	-	109
12	Total Distribution Plant in Service		8,171,969	8,166,446	4,620,933	2,527,067	833,767	179,217	5,462	5,523
13	Test Year Distribution PIS	309	8,171,969	8,166,446	4,620,933	2,527,067	833,767	179,217	5,462	5,523
14	Electric Plant Purchased & Sold	219	0	0	0	0	0	0	0	0
15	General, Common & Intangible									
16	General: Production Related	219	0	0	0	0	0	0	0	0
17	General: Merchant Control	226	0	0	0	0	0	0	0	-
18	General: Power Control Center 138kV	301	0	0	0	0	0	0	0	0
19	General: Power Control Center 46kV	302	0	0	0	0	0	0	0	0
20	General: Functionalized	502	271,455	270,445	148,353	68,029	47,814	6,154	95	1,010
21	General: Reallocated from/(to) Gas	DIR	0	-	-	-	-	-	-	-
22	Common: Functionalized	502	366,714	365,349	200,413	91,902	64,593	8,314	128	1,365
23	Franchises & Consents - Generation	219	0	0	0	0	0	0	0	0
24	Intangible PIS	502	720,995	718,312	394,032	180,687	126,995	16,346	251	2,683
25	Total General, Common & Intangible		1,359,164	1,354,106	742,798	340,618	239,402	30,815	474	5,058

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Depreciation Reserve Summary

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	Production									
2	Production Depreciation Reserve		2,211,253	2,192,192	943,523	530,877	707,727	9,370	695	19,061
3	Generation Step Ups		0	0	0	0	0	0	0	0
4	Total Production		2,211,253	2,192,192	943,523	530,877	707,727	9,370	695	19,061
5	Transmission									
6	Bulk Power Transm	225	-	-	-	-	-	-	-	-
7	Transm; Subtrans	122	0	0	0	0	0	0	0	0
8	Subtransmission	230	0	0	0	0	0	0	0	0
9	Total Transmission		0	0	0	0	0	0	0	0
10	Distribution									
11	Stations and Equipment		693,843	692,913	367,919	218,810	100,017	5,385	782	930
12	Overhead System		1,356,006	1,355,890	825,452	491,212	26,790	12,129	306	116
13	Underground System		301,641	301,458	133,814	79,631	85,046	1,966	1,001	183
14	Meters and Svc Drops		467,880	467,879	309,430	151,450	1,194	5,803	3	0
15	St Lgts and OPL		82,463	82,387	-	-	-	82,387	-	76
16	Total Distribution		2,901,832	2,900,527	1,636,616	941,102	213,046	107,671	2,092	1,305
17	General/Common/Intangible									
18	Total Gen/Comm/Int		749,513	746,724	409,617	187,834	132,019	16,993	261	2,789
19	Total Depreciation Reserve		5,862,598	5,839,443	2,989,756	1,659,813	1,052,792	134,034	3,048	23,155

MICHIGAN PUBLIC SERVICE COMMISSION
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Electric Cost-of-Service Study

Schedule F-1.1

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Depreciation Reserve (prod & tran)

Line No.	Description (a)	Alloc (b)	Total Electric (c)	Total Jurisdictional Electric (d)	Total Residential (e)	Total Commercial Secondary (f)	Total Primary (g)	Total Lighting & Unmetered (h)	Rate GSG (i)	Total Non Jurisdictional (j)
1	Production									
2	Fossil	219	1,458,224	1,445,654	622,212	350,090	466,715	6,179	458	12,570
3	Nuclear	219	0	0	0	0	0	0	0	0
4	Hydro	219	306,248	303,608	130,673	73,524	98,017	1,298	96	2,640
5	Other Production/Combustion Turbine	219	446,781	442,930	190,638	107,263	142,995	1,893	140	3,851
6	Jackson Gas Plant	219	0	0	0	0	0	0	0	0
7	7 Classics	219	0	0	0	0	0	0	0	0
6	Distribution GSUs	219	0	0	0	0	0	0	0	0
7	Total Production		2,211,253	2,192,192	943,523	530,877	707,727	9,370	695	19,061
8	Transmission									
9	Transmission Direct	DIR	0	-	-	-	-	-	-	-
10	Total Subtransmission	228	0	0	0	0	0	0	0	0
11	Total Transmission	123	0	0	0	0	0	0	0	0
12	Total		0	0	0	0	0	0	0	0

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Depreciation Reserve (distribution)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Depreciation Reserve									
2	Distribution Land & Right of Way		-	-	-	-	-	-	-	-
3	345/138kV Substations/Overheads (METC)	127	8,749	8,679	3,478	2,070	3,054	51	26	70
4	345/138kV Substations/Overheads	127	2,295	2,277	912	543	801	13	7	18
5	46/23kV Substations/Overheads	124	9,109	9,103	4,028	2,397	2,589	59	30	6
6	Substations/Overheads (Assignable)	DIR	0	-	-	-	-	-	-	-
7	Overhead Lines Land & ROW	307	11,700	11,698	6,799	3,914	901	79	5	2
8	Total		31,852	31,757	15,218	8,924	7,345	203	69	95
9	Distribution Substations & Equipment									
10	Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
11	138kV HV Subtran/Dist Substations	127	95,282	94,524	37,881	22,542	33,258	557	287	759
12	46kV Subtran /Dist Substations	122	124,811	124,735	55,192	32,844	35,470	811	418	76
13	Distribution Substations	230	58,555	58,555	28,231	16,800	13,104	415	5	-
14	Total		278,648	277,813	121,304	72,186	81,832	1,782	709	835
15	Distribution Overhead System		-	-	-	-	-	-	-	-
16	138kV HV Subtran/Dist Overhead Lines	127	8,116	8,051	3,227	1,920	2,833	47	24	65
17	46kV Subtran Overheads & Transformer Platforms	122	84,300	84,249	37,278	22,184	23,957	548	282	51
18	Single Phase Primary & Secondary	305	1,263,590	1,263,590	784,947	467,108	-	11,534	-	-
19	Total		1,356,006	1,355,890	825,452	491,212	26,790	12,129	306	116
20	Distribution Underground System									
21	Distribution UG System	308	2,541	2,541	1,550	922	46	23	0	-
22	46kV Subtran/Distribution UG Lines	122	299,100	298,917	132,265	78,708	85,000	1,944	1,001	183
23	Total		301,641	301,458	133,814	79,631	85,046	1,966	1,001	183
24	Distribution Line Equipment									
25	Capacitors/Regulators/Transformers	312	383,342	383,342	231,397	137,700	10,840	3,400	4	-
26	Total		383,342	383,342	231,397	137,700	10,840	3,400	4	-
27	Distribution Services									
28	C&I and Residential Services	310	443,919	443,919	295,415	148,505	-	-	-	-
29	Total		443,919	443,919	295,415	148,505	-	-	-	-

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Depreciation Reserve (dist & general)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution Metering Equipment									
2	Metering Equipment (Mass)	170	18,161	18,160	14,015	2,945	1,194	3	3	0
3	Total		18,161	18,160	14,015	2,945	1,194	3	3	0
4	Distribution Installations on Customer Premises									
5	Installations on Premises L4 (Assignable)	DIR	5,800	5,800	-	-	-	5,800	-	-
6	Total		5,800	5,800	-	-	-	5,800	-	-
7	Distribution Streetlighting Equipment									
8	Streetlighting Equipment Depreciation Reserve	311	82,463	82,387	-	-	-	82,387	-	76
9	Total		82,463	82,387	-	-	-	82,387	-	76
10	Distribution Depreciation Reserve		2,901,832	2,900,527	1,636,616	941,102	213,046	107,671	2,092	1,305
11	Test Year Distribution Reserve	317	2,901,832	2,900,527	1,636,616	941,102	213,046	107,671	2,092	1,305
12	General, Common & Intangible									
13	General: Power Control Center	314	0	0	0	0	0	0	0	0
14	General: Functionalized	502	109,502	109,095	59,844	27,442	19,288	2,483	38	407
15	General: Reallocated to Gas	DIR	0	-	-	-	-	-	-	-
16	Common: Functionalized	502	187,030	186,334	102,214	46,871	32,943	4,240	65	696
17	Intangible Amortization Reserve	502	452,981	451,295	247,559	113,521	79,788	10,270	158	1,686
18	Total General, Common & Intangible		749,513	746,724	409,617	187,834	132,019	16,993	261	2,789

MICHIGAN PUBLIC SERVICE COMMISSION
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Electric Cost-of-Service Study

Schedule F-1.1

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CWIP

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production CWIP									
2	Production	219	267,902	265,593	114,312	64,318	85,744	1,135	84	2,309
3	Production: Gas Plant	219	0	0	0	0	0	0	0	0
3	Production: 7 Classics	219	0	0	0	0	0	0	0	0
4	Total Production		267,902	265,593	114,312	64,318	85,744	1,135	84	2,309
5	Transmission CWIP									
6	Transmission	228	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
7	Subtransmission	122	0	0	0	0	0	0	0	0
8	Total Transmission		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
9	Distribution CWIP									
10	HV Distribution	122	41,546	41,521	18,372	10,933	11,807	270	139	25
11	Distribution	306	77,157	77,156	46,315	24,934	3,911	1,993	2	1
12	Other	219	0	0	0	0	0	0	0	0
13	Total Distribution		118,703	118,676	64,687	35,866	15,718	2,263	141	27
14	General/Common/Intangible CWIP									
15	General	502	16,480	16,419	9,007	4,130	2,903	374	6	61
16	Intangible	502	37,800	37,659	20,658	9,473	6,658	857	13	141
17	Common	502	45,866	45,695	25,066	11,494	8,079	1,040	16	171
18	Plant Held for Future Use	502	0	0	0	0	0	0	0	0
19	Other	502	0	0	0	0	0	0	0	0
20	Total Gen/Comm/Int		100,146	99,773	54,731	25,097	17,640	2,270	35	373

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Working Capital

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Current+Accrued Assets									
2	Cash & Cash Equivalents	316	58,344	58,111	29,797	16,197	11,199	888	29	232
3	Accts Receivable	143	298,207	296,453	137,238	75,204	80,780	3,087	145	1,754
4	Material and Supplies	316	88,151	87,800	45,020	24,473	16,920	1,342	44	351
5	Fuel Stock	100	67,802	67,067	25,206	15,237	26,123	467	35	735
6	Real & Personal Property Taxes	316	179,830	179,114	91,842	49,925	34,518	2,739	91	716
7	Other Cur Assets	502	345,005	343,721	188,549	86,461	60,769	7,822	120	1,284
8	Deferred Debits	502	854,469	851,290	466,977	214,137	150,506	19,372	298	3,180
9	Total Current Assets		1,891,807	1,883,555	984,627	481,633	380,814	35,718	763	8,252
10	Current+Accrued Liab									
11	Accounts Payable	316	394,800	393,227	201,630	109,605	75,781	6,012	199	1,572
12	Customer Deposits	143	17,274	17,173	7,950	4,356	4,679	179	8	102
13	Dividends Declared	316	20,560	20,478	10,500	5,708	3,946	313	10	82
14	Accrued Interest	316	44,462	44,285	22,708	12,344	8,534	677	22	177
15	Accrued Taxes - Federal	502	7,531	7,503	4,116	1,887	1,327	171	3	28
16	Accrued Taxes - MSBT	601	2,582	2,572	1,364	683	475	49	1	10
17	Accrued Taxes - R&PP & Other	316	154,890	154,273	79,104	43,001	29,731	2,359	78	617
18	Other Current Liabilities	502	20,266	20,190	11,076	5,079	3,570	459	7	75
19	Deferred CR	502	425,431	423,848	232,503	106,617	74,935	9,645	148	1,583
20	Total Current Liabilities		1,087,796	1,083,549	570,950	289,279	202,979	19,864	478	4,246
21	Total Working Capital		804,011	800,006	413,678	192,355	177,835	15,853	285	4,006

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Adjustments to Rate Base

Line No.	(a) Description		(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Additions to Rate Base										
2	Sales and Use Tax Adjustment		309	0	0	0	0	0	0	0	0
3		0	100	0	0	0	0	0	0	0	0
4		0	219	0	0	0	0	0	0	0	0
5		0	263	0	0	0	0	-	0	-	-
6	Total Additions			0	0	0	0	0	0	0	0
7	Construction Funds Retained from Contractors		330	0	0	0	0	0	0	0	0
8	Customer Advances		309	58,242	58,203	32,934	18,011	5,942	1,277	39	39
9		0	263	0	0	0	0	-	0	-	-
10		0	100	0	0	0	0	0	0	0	0
11		0	100	0	0	0	0	0	0	0	0
12	Total Deductions			58,242	58,203	32,934	18,011	5,942	1,277	39	39
13	Total Adjustments to Rate Base			(58,242)	(58,203)	(32,934)	(18,011)	(5,942)	(1,277)	(39)	(39)

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Electric Cost-of-Service Study

Schedule F-1.1

Case No.: U-20134
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Revenue

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Rate Revenue									
2	Revenue From Electric Sales	DIR	2,178,494	2,167,351	1,194,283	612,773	328,564	29,694	2,036	11,144
3	Provision for Rate Refund	DIR	0	-	-	-	-	-	-	-
4	Unbilled Revenue	DIR	0	-	-	-	-	-	-	-
5	Non PSCR Rate Revenue		2,178,494	2,167,351	1,194,283	612,773	328,564	29,694	2,036	11,144
6	PSCR Base Revenue	DIR	2,009,524	1,995,912	734,361	443,867	804,076	13,608	-	13,612
7	Unbilled PSCR Base Revenue	DIR	0	-	-	-	-	-	-	-
8	GSG Market Price Revenue	DIR	1,548	1,548	-	-	-	-	1,548	-
9	PSCR Rate Revenue		2,011,072	1,997,460	734,361	443,867	804,076	13,608	1,548	13,612
10	Total Rate Revenue		4,189,566	4,164,811	1,928,645	1,056,640	1,132,640	43,302	3,584	24,755
11	Revenue Credits									
12	Late Payment Charge Revenue	DIR	10,227	10,227	5,714	2,932	1,572	-	10	-
13	Renewable Resource Surcharge	150	0	0	0	0	0	0	0	0
14	ERIP	DIR	(0)	-	-	-	-	-	-	(0)
15	Pole Rental Rev	307	11,114	11,112	6,458	3,718	856	75	5	2
16	Other Rents	316	10,041	10,034	5,733	3,058	1,005	232	6	7
17	Enhanced Security Surcharge	DIR	(0)	-	-	-	-	-	-	(0)
18	Interdepartmental	150	0	0	0	0	0	0	0	0
19	Reg Asset 10d(4)	DIR	(0)	-	-	-	-	-	-	(0)
20	PLM Revenues	255	0	0	0	0	0	0	0	-
21	Purchased Power Administrative Fees	100	958	948	356	215	369	7	0	10
22	Miscellaneous Service & Reconnect Fees	253	1,249	1,249	539	336	364	10	0	-
23	Other Revenues	150	4,444	4,398	1,449	903	2,018	27	2	45
24	Securitization Surcharge	DIR	(0)	-	-	-	-	-	-	(0)
25	Job Work Revenue	414	14,201	14,201	8,172	4,185	1,201	638	6	-
26	Non PSCR Revenue Credits		52,233	52,169	28,421	15,345	7,385	988	29	64
27	PSCR Factor Revenue	DIR	26,584	26,584	9,781	5,912	10,709	181	-	-
28	Unbilled PSCR Factor Revenue	DIR	0	-	-	-	-	-	-	-
29	Intersystem Sales	219	80,222	79,531	34,230	19,260	25,676	340	25	692
30	GSG Market Price Capacity Revenue	DIR	0	-	-	-	-	-	-	-
31	PSCR Revenue Credits		106,806	106,114	44,011	25,172	36,385	521	25	692
32	Total Revenue Credits		159,038	158,283	72,432	40,517	43,770	1,509	54	755
33	Total Revenue		4,348,605	4,323,094	2,001,077	1,097,157	1,176,410	44,811	3,638	25,511

Projected 12-Month Period Ending Dec 31, 2019
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O&M (production) 1

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Fuel and Purchased Power									
2	Mid-Peak Summer Fuel for Gen	103	78,529	77,678	28,680	18,426	30,274	267	32	851
3	On-Peak Winter Fuel for Gen	105	204,558	202,341	72,407	48,954	79,874	1,014	92	2,217
4	Off-Peak Summer Fuel for Gen	104	70,952	70,183	27,511	14,566	27,426	634	45	769
5	Off-Peak Winter Fuel for Gen	106	138,019	136,523	53,530	29,261	52,237	1,413	83	1,496
6	Critical Summer Peak Energy	107	38,253	37,838	13,933	9,538	14,251	105	11	415
7	Total Fuel Expense		530,311	524,562	196,060	120,744	204,062	3,433	263	5,749
8	Mid-Peak Summer Purchased Power	103	65,690	64,978	23,991	15,413	25,324	223	27	712
9	On-Peak Winter Purchased Power	105	171,112	169,258	60,569	40,950	66,814	849	77	1,855
10	Off-Peak Summer Purchased Power	104	59,351	58,708	23,013	12,184	22,942	531	38	643
11	Off-Peak Winter Purchased Power	106	115,453	114,201	44,778	24,476	43,696	1,182	69	1,252
12	Critical Peak Summer Purchased Power	107	31,998	31,651	11,655	7,979	11,921	88	9	347
13	Purchased Power Capacity	219	710,811	704,684	303,297	170,651	227,500	3,012	223	6,127
14	Total P&I		1,154,415	1,143,479	467,301	271,653	398,198	5,884	443	10,936
15	Total Fuel and P&I		1,684,726	1,668,042	663,361	392,397	602,260	9,317	706	16,685

Projected 12-Month Period Ending Dec 31, 2019
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O&M (production) 2

Line No.	(a) Description		(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Fossil Plant O&M Total										
2	Capacity Related Operations		219	41,677	41,317	17,783	10,006	13,339	177	13	359
3	Capacity Related Maintenance		219	4,728	4,687	2,017	1,135	1,513	20	1	41
4	Energy Related Operations		100	7,228	7,150	2,687	1,624	2,785	50	4	78
5	Energy Related Maintenance		100	50,599	50,051	18,810	11,371	19,495	349	26	548
6	Capacity Related Fuel Handling		219	0	0	0	0	0	0	0	0
7	Energy Related Fuel Handling		100	13,437	13,291	4,995	3,020	5,177	93	7	146
8	Total Fossil O&M Total			117,668	116,496	46,293	27,155	42,308	688	51	1,173
9	Nuclear Plant O&M Total										
10	Capacity Related Operations		219	0	0	0	0	0	0	0	0
11	Capacity Related Maintenance		219	0	0	0	0	0	0	0	0
12	Energy Related Maintenance		100	0	0	0	0	0	0	0	0
13	523 Electric Expenses		219	0	0	0	0	0	0	0	0
14	524 Miscellaneous		219	0	0	0	0	0	0	0	0
15	Total Nuc O&M Total			0	0	0	0	0	0	0	0
16	Hydro Plant O&M Total										
17	Capacity Related Operations		219	8,667	8,592	3,698	2,081	2,774	37	3	75
18	Capacity Related Maintenance		219	937	929	400	225	300	4	0	8
19	Energy Related Operations		100	981	971	365	221	378	7	1	11
20	Energy Related Maintenance		100	4,321	4,274	1,606	971	1,665	30	2	47
21	540 Rents		219	0	0	0	0	0	0	0	0
22	Total Hydro O&M Total			14,906	14,765	6,069	3,497	5,116	77	6	140
23	Other Power O&M Total										
24	Capacity Related Operations & Maintenance		219	38,840	38,505	16,573	9,325	12,431	165	12	335
25	Energy Related Operations & Maintenance		100	0	0	0	0	0	0	0	0
26		0	100	0	0	0	0	0	0	0	0
27	Total Other Power O&M Total			38,840	38,505	16,573	9,325	12,431	165	12	335
28	Other Power Supply Expense										
29	Capacity Related Sys Cntl Load Disp		219	10,151	10,064	4,332	2,437	3,249	43	3	88
30	Energy Related Sys Cntl Load Disp		100	0	0	0	0	0	0	0	0
31	Total Other O&M Expense			10,151	10,064	4,332	2,437	3,249	43	3	88
32	Disposition of Allowances		219	0	0	0	0	0	0	0	0
33	Total Production O&M Excluding Fuel and P&I			181,565	179,830	73,266	42,414	63,105	972	73	1,735
34	Total Prod O&M Expense			1,866,291	1,847,872	736,627	434,811	665,365	10,290	778	18,420

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O&M (transmission & adjustments)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Transmission O&M									
2	Transmission	120	439,642	435,533	185,335	102,122	145,684	2,297	94	4,109
3	Miscellaneous	127	0	0	0	0	0	0	0	0
4	Other	120	0	0	0	0	0	0	0	0
5	Total Transmission Expense		439,642	435,533	185,335	102,122	145,684	2,297	94	4,109
6	O&M Adjustments									
7	Tax Benefit of Proforma Interest & Interest Synchronization Adjustment	150	0	0	0	0	0	0	0	0
8	Other Advertising Programs - Disallowance	412	0	0	0	0	0	0	0	0
9	Income Tax Effect of Interest	390	0	0	0	0	0	0	0	0
10	Charitable, Civic, Dues & Donations	412	0	0	0	0	0	0	0	0
11	Transmission reclass (indirect costs)	DIR	0	-	-	-	-	-	-	-
12	Streetlighting O&M	DIR	0	-	-	-	-	-	-	-
13	Customer O&M	411	0	0	0	0	0	0	0	0
14	Administrative and General O&M	412	0	0	0	0	0	0	0	0
15	Other O&M Inflation	443	0	0	0	0	0	0	0	0
16	Other O&M Adjmts	438	0	0	0	0	0	0	0	0
17	Total O&M Adjustments		0	0	0	0	0	0	0	0

Projected 12-Month Period Ending Dec 31, 2019
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O&M (distribution)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Alloc	Total Electric	Total Jurisdictional Electric	Total Residential	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
1	Distribution Operation									
2	580 Supv & Engineering - Distribution	400	25,089	25,084	14,701	6,068	1,543	2,766	5	5
3	580 Supv & Engineering - 138kV	402	191	190	83	46	60	0	0	2
4	580 Supv & Engineering - 46kV	404	1,992	1,990	881	524	566	13	7	1
5	581 Load Dispatch - Distribution	301	0	0	0	0	0	0	0	0
6	582 Station Expense - Distribution	230	2,022	2,022	975	580	453	14	0	-
7	582 Station Expense - 138kV	303	0	0	0	0	0	0	0	0
8	582 Station Expense - 46kV	304	0	0	0	0	0	0	0	0
9	583 Overhead Expense - Distribution	307	6,753	6,752	3,924	2,259	520	46	3	1
10	583 Overhead Expense - 138kV	121	67	67	29	16	21	0	0	1
11	583 Overhead Expense - 46kV	122	700	699	309	184	199	5	2	0
12	584 Underground Exp	308	3,978	3,978	2,427	1,444	72	36	0	-
13	585 St Lt	311	2,559	2,557	-	-	-	2,557	-	2
14	586 - Metering Expense	313	3,721	3,721	2,872	603	245	1	1	0
15	587 Cust Instl Expense	160	3,400	3,400	2,989	401	8	1	0	0
16	588 Miscellaneous	400	15,249	15,246	8,936	3,688	938	1,681	3	3
17	589 Rents	309	2,050	2,049	1,159	634	209	45	1	1
18	Total Dist Operation Expense		67,771	67,755	39,285	16,449	4,834	7,164	22	17
19	Distribution Maintenance									
20	590 Supv & Engineering - Distribution	401	6,873	6,872	3,982	2,245	566	76	2	1
21	590 Supv & Engineering - 138kV	403	125	124	50	30	43	1	0	1
22	590 Supv & Engineering - 46kV	405	216	216	96	57	61	1	1	0
23	591 Structures - Distribution	230	436	436	210	125	98	3	0	-
24	591 Structures - 138kV	303	48	47	19	11	17	0	0	0
25	591 Structures - 46kV	304	54	54	24	14	15	0	0	0
26	592 Station Equipment - Distribution	230	8,610	8,610	4,151	2,470	1,927	61	1	-
27	592 Station Equipment - 138kV	303	1,592	1,580	633	377	556	9	5	13
28	592 Station Equipment - 46kV	304	1,806	1,805	799	475	513	12	6	1
29	593 Overhead Lines - Distribution	307	83,186	83,173	48,341	27,827	6,409	561	35	13
30	593 Overhead Lines - 138kV	224	111	111	48	27	35	0	0	-
31	593 Overhead Lines - 46kV	122	1,156	1,155	511	304	329	8	4	1
32	594 Underground Lines - Distribution	308	4,152	4,152	2,533	1,507	75	37	0	-
33	594 Underground Lines - 138kV	121	0	0	0	0	0	0	0	0
34	594 Underground Lines - 46kV	122	23	23	10	6	7	0	0	0
35	595 Line Xfmrs	312	8,687	8,687	5,244	3,120	246	77	0	-
36	596 St Lts & OPL	311	473	472	-	-	-	472	-	0
37	597 Meters	313	3,464	3,464	2,673	562	228	1	1	0
38	598 Miscellaneous	401	232	232	135	76	19	3	0	0
39	Total Dist Maintenance Expense		121,245	121,215	69,459	39,235	11,144	1,323	55	30
40	Total Distribution O&M Expense		189,016	188,969	108,743	55,684	15,978	8,487	77	47

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O&M (customer & A&G)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Customer Accounts Expense									
2	901 Supervision	408	5,626	5,626	4,953	664	8	1	0	0
3	902 Meter Reading	263	14,313	14,313	12,618	1,693	-	2	-	-
4	903 Rcrds & Collection	160	5,928	5,928	5,213	699	14	2	0	0
5	904 Uncollectibles	264	18,594	18,594	16,357	2,194	43	-	0	0
6	905 Misc Expenses	408	0	0	0	0	0	0	0	0
7	Total Customer Accounts		44,461	44,461	39,141	5,251	64	5	0	0
8	Customer Services									
9	907 Supervision	160	545	545	480	64	1	0	0	0
10	908 Customer Assist	603	5,870	5,810	1,914	1,192	2,665	35	3	60
11	909 Info & Inst	160	2,278	2,278	2,003	269	5	1	0	0
12	910 Miscellaneous	160	0	0	0	0	0	0	0	0
13	Total Customer Services		8,693	8,634	4,397	1,525	2,672	37	3	60
14	Sales Expense									
15	911 Supervision	160	0	0	0	0	0	0	0	0
16	912 Demo & Selling	160	165	165	145	20	0	0	0	0
17	913 Advertising	160	0	0	0	0	0	0	0	0
18	916 Miscellaneous	160	0	0	0	0	0	0	0	0
19	Total Sales Expense		165	165	145	20	0	0	0	0
20	Administrative & General									
21	Production	500	62,661	62,121	26,737	15,044	20,055	266	20	540
22	HV Distribution	406	3,868	3,858	1,671	992	1,160	24	12	9
23	Distribution	407	86,596	86,584	50,390	25,646	6,461	4,063	24	12
24	Customer	409	19,351	19,329	15,850	2,467	996	15	1	22
25	Total Admin & General		172,475	171,892	94,648	44,148	28,671	4,367	57	584
26	Total O&M Excluding PSCR Expense		596,376	593,951	320,340	149,042	110,490	13,869	210	2,425
27	Total O & M Expense		2,720,745	2,697,526	1,169,037	643,561	858,435	25,483	1,010	23,219

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(thousands of dollars)

Depreciation Expense Summary

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production									
2	Production Depreciation Expense		293,358	290,829	125,173	70,429	93,891	1,243	92	2,529
3	GSU Depreciation Expense		0	0	0	0	0	0	0	0
4	Production Test Year Change	219	0	0	0	0	0	0	0	0
5	Total Production		293,358	290,829	125,173	70,429	93,891	1,243	92	2,529
6	Transmission									
7	Bulk Power Transm		0	-	-	-	-	-	-	-
8	Transm; Subtrans		0	0	0	0	0	0	0	0
9	Subtransmission		0	0	0	0	0	0	0	0
10	Total Transmission		0	0	0	0	0	0	0	0
11	Distribution									
12	Stations and Equipment		59,707	59,605	30,478	18,132	10,446	447	101	102
13	Overhead System		110,330	110,314	66,204	39,397	3,698	973	42	16
14	Underground System		18,009	18,009	10,986	6,537	325	161	0	-
15	Meters and Svc Drops		56,111	56,110	40,192	13,731	1,885	298	4	0
16	St Lgts and OPL		4,226	4,222	-	-	-	4,222	-	4
17	Test Year Distribution Change	444	0	0	0	0	0	0	0	0
18	Total Distribution		248,383	248,260	147,860	77,798	16,353	6,101	148	123
19	General/Common/Intangible									
20	Total Gen/Comm/Int		113,668	113,245	62,121	28,486	20,021	2,577	40	423
21	Test Year Gen/Comm/Int Change	445	0	0	0	0	0	0	0	0
22	Total General/Common/Intangible Dep Expense		113,668	113,245	62,121	28,486	20,021	2,577	40	423
23	Total Other Amortization Expense		0	0	0	0	0	0	0	0
24	Total Depreciation & Amortization Expense		655,409	652,335	335,154	176,713	130,266	9,922	280	3,074
25	Test Year Dep & Amort Exp	442	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	280	3,074

Projected 12-Month Period Ending Dec 31, 2019
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(thousands of dollars)

Depreciation Expense (prod & tran)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Production									
2	Direct		-	-	-	-	-	-	-	-
3	Fossil	219	210,412	208,598	89,781	50,516	67,344	892	66	1,814
4	Nuclear	219	0	0	0	0	0	0	0	0
5	Hydro	219	41,350	40,994	17,644	9,927	13,234	175	13	356
6	Other Production	219	41,596	41,237	17,749	9,986	13,313	176	13	359
7	Distribution GSUs	219	0	0	0	0	0	0	0	0
8	Jackson Gas Plant	219	0	0	0	0	0	0	0	0
9	7 Classics	219	0	-	-	-	-	-	-	-
10	Total Production Depreciation Expense		293,358	290,829	125,173	70,429	93,891	1,243	92	2,529
11	Transmission									
12	Direct		0	-	-	-	-	-	-	-
13	Transmission	127	0	0	0	0	0	0	0	0
14	Subtransmission	123	0	0	0	0	0	0	0	0
15	Total Transmission Depreciation Expense		0	0	0	0	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Schedule F-1.1

Case No.: U-20134
Exhibit No.: A-16 (JCA-2)
Schedule: F-1.1
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Depreciation Expense (distribution)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution									
2	360A Land & Rights-Direct		-	-	-	-	-	-	-	-
3	138kV Substations/Overheads (METC)	127	336	334	134	80	117	2	1	3
4	138kV Substations/Overheads	127	175	174	70	41	61	1	1	1
5	46kV Substations/Overheads	124	509	508	225	134	145	3	2	0
6	Substations/Overheads (Assignable)	DIR	0	-	-	-	-	-	-	-
7	Overhead Lines Land & ROW	307	416	416	242	139	32	3	0	0
8	Total		1,436	1,432	670	394	355	9	3	4
9	Distribution Substations & Equipment									
10	Customer Substations (Assignable)	DIR	0	-	-	-	-	-	-	-
11	138kV HV Subtran/Dist Substations	127	10,786	10,700	4,288	2,552	3,765	63	32	86
12	Distribution Substations	124	19,472	19,460	8,611	5,124	5,534	127	65	12
13	Total		30,258	30,160	12,899	7,676	9,298	190	98	98
14	Overhead System									
15	138kV HV Subtran/Dist Overhead Lines	127	1,108	1,100	441	262	387	6	3	9
16	46kV Subtran Overheads & Transformer Platforms	122	11,651	11,644	5,152	3,066	3,311	76	39	7
17	Overhead System	305	97,571	97,571	60,611	36,069	-	891	-	-
19	Total		110,330	110,314	66,204	39,397	3,698	973	42	16
20	Underground System									
21	Underground System	308	18,009	18,009	10,986	6,537	325	161	0	-
22	Total		18,009	18,009	10,986	6,537	325	161	0	-
23	Distribution Line Equipment									
24	Line Equipment	312	28,013	28,013	16,910	10,063	792	248	0	-
25	Total		28,013	28,013	16,910	10,063	792	248	0	-
26	Distributions Services									
27	Overhead & Underground Services	310	27,147	27,147	18,065	9,081	-	-	-	-
28	Total		27,147	27,147	18,065	9,081	-	-	-	-

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Depreciation Expense (dist & general)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Distribution (cont.)									
2	Distribution Metering Equipment		-	-	-	-	-	-	-	-
3	Metering Equipment	170	28,671	28,670	22,127	4,649	1,885	5	4	0
4	Total		28,671	28,670	22,127	4,649	1,885	5	4	0
5	Installations on Customer Premises L4	DIR	293	293	-	-	-	293	-	-
6	Street & Highway Lighting Depreciation Expense	311	4,226	4,222	-	-	-	4,222	-	4
7	Total Distribution Depreciation Expense		248,383	248,260	147,860	77,798	16,353	6,101	148	123
8	General/Common/Intangible									
9	General	502	11,885	11,841	6,495	2,978	2,093	269	4	44
10	Common	502	20,412	20,336	11,155	5,115	3,595	463	7	76
11	Intangible Amortization	502	81,371	81,068	44,470	20,392	14,333	1,845	28	303
12	Total Gen/Comm/Int Depreciation Expense		113,668	113,245	62,121	28,486	20,021	2,577	40	423
13	Other Amortization									
14	Amort of 7 Classics Inventory	219	0	0	0	0	0	0	0	0
15	AFUDC in Excess of FERC Rate	330	0	0	0	0	0	0	0	0
16	Securitized Regulatory Assets (MPSC Case U-12505)	150	0	0	0	0	0	0	0	0
17	ARO Accretion/Transition Expense	219	0	0	0	0	0	0	0	0
18	Total Other Amortization Expense		0	0	0	0	0	0	0	0
19	Total Depreciation & Amortization Expense		655,409	652,335	335,154	176,713	130,266	9,922	280	3,074

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4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Tax

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	City Income Tax	150	1,299	1,285	423	264	590	8	1	13
2	Michigan Single Business Tax	601	0	0	0	0	0	0	0	0
3	Michigan Business Tax	439	38,881	38,962	19,948	11,218	7,363	320	113	(81)
3	R&PP Taxes - Prod	219	65,038	64,477	27,751	15,614	20,816	276	20	561
4	R&PP Taxes - High Voltage Dist	302	21,547	21,533	9,528	5,670	6,123	140	72	13
5	R&PP Taxes - Low Voltage Dist	306	67,163	67,162	40,316	21,704	3,405	1,735	2	1
6	R&PP Taxes - General	315	3,081	3,069	1,672	771	556	68	1	12
7	R&PP Taxes - Common/Intangible	502	12,534	12,487	6,850	3,141	2,208	284	4	47
8	R&PP Taxes - PHFFU	226	38	38	18	10	10	0	0	-
9	R&PP Taxes - CWIP	330	0	0	0	0	0	0	0	0
10	Total R&PP Taxes		169,400	168,766	86,135	46,910	33,118	2,503	100	634
11	Payroll Related Taxes	502	21,509	21,429	11,755	5,390	3,789	488	7	80
12	Miscellaneous General Taxes	150	0	0	0	0	0	0	0	0
13	Total Payroll/Miscellaneous Taxes		21,509	21,429	11,755	5,390	3,789	488	7	80
14	MPSC Assessment Fee	150	9,266	9,172	3,022	1,882	4,207	56	4	94
15	Total Other Taxes		240,354	239,614	121,282	65,664	49,067	3,375	225	740
16	Federal Income Tax Provision	439	110,944	111,175	56,920	32,009	21,010	914	322	(231)
17	Total Taxes Other Than Income		201,473	200,652	101,335	54,446	41,704	3,055	113	821
18	Total Income Taxes		149,825	150,137	76,868	43,226	28,374	1,234	435	(312)
19	Total Taxes		351,299	350,789	178,203	97,673	70,077	4,289	547	510

Projected 12-Month Period Ending Dec 31, 2019
Version 2
4CP Average & Excess Production and 12CP Transmission
(thousands of dollars)

Adjustments to Income Statement

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Jurisdictional Electric	(e) Total Residential	(f) Total Commercial Secondary	(g) Total Primary	(h) Total Lighting & Unmetered	(i) Rate GSG	(j) Total Non Jurisdictional
1	Adjustments to NOI - Miscellaneous	316	0	0	0	0	0	0	0	0
2	Interest Expense Securitization I	150	0	0	0	0	0	0	-	0
3	Gain/Losses from Disposition of Utility Plant	316	0	0	0	0	0	0	0	0
4	Disallowed Corp Memb	502	0	0	0	0	0	0	0	0
5	Advertising	225	0	0	0	0	0	0	0	0
6	Interest Synch Adj	390	0	0	0	0	0	0	0	0
7	Allowable Charitable	140	0	0	0	0	0	0	0	0
8	MERC Consolidation	219	0	0	0	0	0	0	0	0
9	Clean Air Act	226	0	0	0	0	0	0	0	-
10	AFUDC	330	8,834	8,785	4,242	2,274	2,162	103	5	49
11	Income Tax Adjustment	226	0	0	0	0	0	0	0	-
12	Total Other Adjustments		8,834	8,785	4,242	2,274	2,162	103	5	49

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study
Capacity Related Cost and Charge Calculation
Planning Year 2019/2020
(thousands of dollars)

Case No.: U-20134
Exhibit No.: A-30 (JCA-3)
Page: 1 of 1
Witness: JCAponte
Date: May 2018

Line No.	(a) Description	(b) Total Electric	
1	Total Production Related Cost	$ 3,034,355	
2	Non-Capacity Related Cost:		
3	Fuel Expense	$ 530,311	
4	Purchased & Interchanged	443,604	
5	Energy Related Other O&M Expense	76,566	
6	PSCR Revenue Credits	(106,806)	
7	Non-PSCR Revenue Credits	(10,153)	
8	Transmission Expense	439,642	
9	Total Non-Capacity Related Cost	$ 1,373,164	Σ Lines 2:8
10	**Total Capacity Related Cost**	**$ 1,661,190**	Line 1 - Line 9
11	Offsets:		
12	Energy Market Sales	$ 1,055,176	
13	Off-System Energy Sales	11,433	
14	Ancillary Service Sales	22,576	
15	Bilateral Energy Sales	-	
16	Total Revenue	$ 1,089,185	Σ Lines 12:15
17	Related Fuel Cost	467,766	
18	**Total Revenue Less Fuel Cost**	**$ 621,419**	Line 16 - Line 17
19	**Net Capacity Cost**	**$ 1,039,771**	Line 10 - Line 18
20	**Capacity Charge Demand (MW)**	**7,522**	
21	**Capacity Charge (MW/Day)**	**$378.71**	(Line 19 x 1,000) ÷ Line 21

Source:
Lines 1-10: Electric Cost-of-Service Study model, "Prod" tab
Lines 11-17: Testimony of Company Witness RTBlumenstock
Line 20: Case No. U-18441, Exhibit 2, column (c), (line 1 x line 4) ÷ (1 + line 6)

Line No.	(a) **Description**	(b) **Rate GPD Voltage 1**	(c) **Rate GPD Voltage 2**
1	Plant in Service	$ 38,293	$ 38,805
2	Depreciation Reserve	(9,013)	(10,239)
3	Net Plant	29,280	28,566
4	Working Capital	1,167	1,692
5	CWIP (HV Distribution)	-	1,011
6	Substation Rate Base	$ 30,447	$ 31,269
7	Pre-Tax ROE	7.53%	7.53%
8	Pre-Tax Return	$ 2,294	$ 2,356
9	Depreciation Expense	957	1,426
10	O&M Expense	139	132
11	Other Taxes	763	1,903
12	Revenue Credits	(241)	(279)
13	Total Revenue Requirement	$ 3,912	$ 5,537
14	Max Demand (MW)	8,476	5,769
15	Substation Ownership Credit (kW)	$ 0.46	$ 0.96

Source: Exhibit A-16 (JCA-2), Schedule F-1.1, Test Year COSS – Version 2
Exhibit A-16 (LMC-3), Schedule F-3, Present and Proposed Revenue Detail
WP-JCA-193-194

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism
Allocation of Incremental Revenue Requirement for 2020 and 2021
(thousands of dollars)

Case No.: U-20134
Exhibit No.: A-32 (JCA-5)
Page: 1 of 3
Witness: JCAponte
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Alloc	Total Electric	Total Jurisdictional Electric	Total Residential	Total Commercial Secondary	Total Primary	Total Lighting & Unmetered	Rate GSG	Total Non Jurisdictional
1	Distribution Total Revenue[1]		1,333,644	1,322,466	754,169	374,958	160,420	30,856	2,064	11,178
2	Distribution Revenue Deficiency (Sufficiency)[1]		(71,280)	(60,091)	(978)	(12,840)	(45,754)	976	(1,495)	(11,189)
3	Distribution Revenue Requirement - Allocator 602		100.00%	100.00%	59.67%	28.69%	9.08%	2.52%	0.05%	0.00%
4	2020 Incremental Revenue Requirement[2]	602	$ 48,850	$ 48,850	$ 29,146	$ 14,013	$ 4,437	$ 1,232	$ 22	$ (0)
5	2021 Incremental Revenue Requirement[2]	602	$ 97,281	$ 97,282	$ 58,043	$ 27,906	$ 8,836	$ 2,453	$ 44	$ (1)

(1) Test Year Electric Cost-of-Service Study – Version 2, Model, "Dist" tab
(2) Total from Exhibit A-107 (HJM-63), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism
Allocation of Incremental Revenue Requirement for 2020 and 2021
(thousands of dollars)

Case No.: U-20134
Exhibit No.: A-32 (JCA-5)
Page: 2 of 3
Witness: JCAponte
Date: May 2018

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)	(j)
Line No.	Description	Alloc	Rate RS	Rate RT	Total Residential		Rate GS	Rate GSD	Rate GS GEI	Rate GSD GEI	Total Commercial Secondary
1	Distribution Total Revenue[1]		754,169	-	754,169		212,361	147,114	5,002	10,480	374,958
2	Distribution Revenue Deficiency (Sufficiency)[1]		(978)	-	(978)		(141)	(18,220)	2,449	3,072	(12,840)
3	Distribution Revenue Requirement - Allocator 602		59.67%	0.00%	59.67%		16.81%	10.21%	0.59%	1.07%	28.69%
4	2020 Incremental Revenue Requirement[2]	602	$29,146	$ -	$ 29,146	$ -	$ 8,212	$ 4,988	$ 288	$ 524	$ 14,013
5	2021 Incremental Revenue Requirement[2]	602	$58,043	$ -	$ 58,043	$ -	$16,354	$ 9,933	$ 574	$ 1,044	$ 27,906

(1) Test Year Electric Cost-of-Service Study – Version 2, Model, "Dist" tab
(2) Total from Exhibit A-107 (HJM-63), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism
Allocation of Incremental Revenue Requirement for 2020 and 2021
(thousands of dollars)

Case No.: U-20134
Exhibit No.: A-32 (JCA-5)

Witness: JCAponte
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.	Description	Alloc	Rate GP	Rate GPD Vlt 1	Rate GPD Vlt 2	Rate GPD Vlt 3	Rate GP GEI	Rate EIP	Rate GPD GEI Vlt 1	Rate GPD GEI Vlt 2	Rate GPD GEI Vlt 3	Total Primary	Rate GML	Rate GUL	Rate GU-XL	Rate GU	Total Lighting & Unmetered
1	Distribution Total Revenue[1]		23,671	9,043	43,139	72,633	3,851	796	179	791	6,315	160,420	1,029	28,212	1	1,614	30,856
2	Distribution Revenue Deficiency (Sufficiency)[1]		(5,919)	(1,993)	(29,684)	(8,206)	52	548	(84)	155	(623)	(45,754)	(9)	971	1	12	976
3	Distribution Revenue Requirement - Allocator 602		1.41%	0.56%	1.07%	5.10%	0.31%	0.11%	0.01%	0.07%	0.45%	9.08%	0.08%	2.31%	0.00%	0.13%	2.52%
4	2020 Incremental Revenue Requirement[2]	602	$ 687	$ 273	$ 521	$2,493	$ 151	$ 52	$ 4	$ 37	$ 220	$ 4,437	$ 39	$1,129	$ 0	$ 63	$ 1,232
5	2021 Incremental Revenue Requirement[2]	602	$1,368	$ 543	$ 1,037	$4,965	$ 301	$ 104	$ 7	$ 73	$ 439	$ 8,836	$ 79	$2,249	$ 0	$ 125	$ 2,453

(1) Test Year Electric Cost-of-Service Study – Version 2, Model, "Dist" tab
(2) Total from Exhibit A-107 (HJM-63), line 12

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief. _______________________________________	))))))	Case No. U-20134

EXHIBITS

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20134
Exhibit No.: A-33 (RTB-1)

Witness: RTBlumenstock
Date: May 2018

2019 Power Supply Cost Recovery Forecast

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
						SUMMARY BY SOURCE								
Line No.	Description	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2019
	ENERGY (MWH)													
1	COAL STEAM	1,176,616	1,015,556	868,312	678,404	975,331	956,460	1,026,022	1,035,044	762,477	333,033	538,239	1,132,639	10,498,135
2	GAS & OIL	466,028	421,559	502,316	512,901	301,183	497,164	656,262	548,878	481,412	542,167	534,897	497,534	5,962,302
3	NUCLEAR PPA	602,225	541,987	594,828	569,544	581,868	554,040	568,572	568,284	557,328	588,996	576,677	600,328	6,904,676
4	STATION POWER	5,677	5,469	10,005	10,538	6,606	5,709	5,876	6,044	10,245	17,269	13,124	6,134	102,697
5	CE OWNED RENEWABLES	117,013	99,439	115,266	121,956	107,589	83,980	69,951	65,169	75,532	92,792	101,233	108,971	1,158,892
6	PEAKERS	0	17,632	23,220	95,200	39,751	58,049	100,863	78,251	35,963	10,860	1,200	0	460,989
7	PUMPED STORAGE	75,373	72,508	83,533	99,986	104,173	96,631	102,511	103,655	76,694	64,807	56,983	69,377	1,006,231
8	TOTAL GENERATED	2,442,932	2,174,151	2,197,480	2,088,529	2,116,500	2,252,034	2,530,058	2,405,325	1,999,652	1,649,925	1,822,353	2,414,982	26,093,922
9	LESS : PUMPING	-101,238	-93,417	-111,016	-125,847	-132,086	-132,702	-126,465	-135,678	-102,487	-88,247	-69,099	-86,176	-1,304,457
10	TOTAL GENERATED	2,341,695	2,080,734	2,086,464	1,962,681	1,984,414	2,119,332	2,403,594	2,269,647	1,897,165	1,561,678	1,753,254	2,328,807	24,789,464
11	PURCHASED (NUGs)	828,868	708,998	898,277	816,627	855,880	724,132	909,636	804,593	793,146	837,163	755,885	758,087	9,691,292
12	NET INTERCHANGE	-18,599	77,196	-49,312	-60,149	24,191	237,632	44,319	277,192	276,695	373,381	381,927	22,989	1,587,463
13	TOTAL SYSTEM REQUIREMENTS	3,151,963	2,866,928	2,935,429	2,719,160	2,864,485	3,081,095	3,357,549	3,351,431	2,967,007	2,772,222	2,891,066	3,109,883	36,068,219
	VARIABLE EXPENSES ($*1000)													
14	COAL STEAM	29,366	25,358	22,092	17,270	24,697	24,212	25,744	26,014	19,124	8,501	13,633	28,193	264,205
15	GAS & OIL	13,354	11,909	13,888	12,299	7,656	11,938	17,182	13,316	11,800	12,989	13,038	12,982	152,352
16	NUCLEAR PPA VARIABLE	4,538	3,519	3,690	3,605	3,778	4,197	4,825	4,806	4,224	3,731	3,558	3,837	48,310
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	3,931	3,220	3,277	3,243	2,858	2,327	2,767	2,846	2,358	2,983	3,218	3,576	36,605
19	PEAKERS	0	661	909	2,934	1,238	1,777	3,116	2,417	1,133	378	43	0	14,605
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TOTAL GENERATED	51,190	44,668	43,856	39,351	40,226	44,451	53,635	49,400	38,639	28,582	33,490	48,589	516,076
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	51,190	44,668	43,856	39,351	40,226	44,451	53,635	49,400	38,639	28,582	33,490	48,589	516,076
24	PURCHASED (NUGs) VARIABLE COST[1]	31,679	28,410	33,226	29,304	29,581	25,689	33,575	29,397	25,600	25,854	22,099	22,125	336,539
25	NET INTERCHANGE, EXCLUDING ZRC	-474	1,674	-1,615	-3,266	-1,289	4,094	-2,532	5,736	6,713	9,869	11,589	843	31,343
26	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**82,395**	**74,751**	**75,467**	**65,389**	**68,519**	**74,234**	**84,678**	**84,533**	**70,951**	**64,305**	**67,179**	**71,557**	**883,958**
27	ZONAL RESOURCE CREDIT PURCHASE	88	79	88	85	88	98	102	102	98	102	98	102	1,129
28	C&I DR COST	368	368	368	368	368	368	368	368	368	368	368	368	4,410
29	OWNED RENEWABLE CAPACITY	1,629	1,334	1,358	1,344	1,184	964	1,147	1,179	977	1,236	1,334	1,482	15,170
30	NUCLEAR PPA CAPACITY	32,365	25,098	26,316	25,706	26,942	29,928	34,411	34,276	30,122	26,608	25,371	27,366	344,508
31	PURCHASED (NUG) CAPACITY	21,730	20,436	21,863	21,327	21,606	21,626	22,555	22,277	21,122	21,462	20,222	20,646	256,872
32	PURCHASED (NUG) FIXED ENERGY	7,255	6,597	7,274	7,301	7,476	7,441	7,633	7,626	7,407	7,634	7,438	7,641	88,722
33	**TOTAL CAPACITY AND NUG FIXED COSTS**	**63,433**	**53,913**	**57,266**	**56,131**	**57,663**	**60,425**	**66,215**	**65,827**	**60,094**	**57,409**	**54,830**	**57,604**	**710,811**
34	TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION	34,551	32,831	32,815	30,133	34,809	41,761	46,340	44,125	40,960	32,753	33,382	35,186	439,642
35	ACTIVATED CARBON	126	126	126	126	126	126	126	126	126	126	126	126	1,517
36	MISO - SCHEDULE 2 (REACTIVE)	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-4,500
37	AQUEOUS AMMONIA EXPENSE	110	110	110	110	110	110	110	110	110	110	110	110	1,318
38	UREA EXPENSE	152	152	152	152	152	152	152	152	152	152	152	152	1,829
39	LIME EXPENSE	798	798	798	798	798	798	798	798	798	798	798	798	9,571
40	**TOTAL POWER SUPPLY COSTS**	**181,191**	**162,306**	**166,359**	**152,464**	**161,802**	**177,231**	**198,044**	**195,296**	**172,816**	**155,278**	**156,201**	**165,157**	**2,044,146**

[1]Purchased (NUG) variable costs include costs associated with PURPA variable energy payments, non-capacity renewable energty plan transfer costs, the green generation program, energy only NUGs and certain hydro plant contract costs.

2019 Power Supply Cost Recovery Forecast

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Line No.	Description	PURCHASED AND INTERCHANGE POWER REPORT JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2019
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)													
41	MARKET ON PEAK	34,645	61,505	19,267	5,922	44,745	106,357	104,089	136,949	125,967	98,857	182,814	80,311	1,001,426
42	MARKET OFF PEAK	107,977	169,183	119,384	200,249	245,407	311,343	268,431	324,952	265,062	341,432	260,833	116,852	2,731,106
43	PURCHASED (NUGs)	828,868	708,998	898,277	816,627	855,880	724,132	909,636	804,593	793,146	837,163	755,885	758,087	9,691,292
44	TOTAL RECEIVED	971,490	939,685	1,036,928	1,022,798	1,146,031	1,141,832	1,282,156	1,266,493	1,184,175	1,277,452	1,199,532	955,251	13,423,824
	NET INTERCHANGE DELIVERED (MWH)													
45	EXTERNAL SALES	161,221	153,491	187,963	266,320	265,961	180,068	279,409	180,089	114,334	66,908	61,720	174,175	2,091,659
46	MISO RAC	0	0	0	0	0	0	48,791	4,619	0	0	0	0	53,410
47	TOTAL DELIVERED	161,221	153,491	187,963	266,320	265,961	180,068	328,200	184,709	114,334	66,908	61,720	174,175	2,145,070
48	NET (MWH)	810,269	786,194	848,965	756,478	880,070	961,764	953,955	1,081,785	1,069,841	1,210,544	1,137,812	781,076	11,278,754

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20134
Exhibit No.: A-25 (RTB-1)

Witness: RTBlumenstock
Date: May 2018

2019 Power Supply Cost Recovery Forecast

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		PURCHASED AND INTERCHANGE POWER REPORT												
Line No.	Description	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2019
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)													
49	MARKET ON PEAK ENERGY	2,533	3,171	2,039	1,493	2,746	4,589	5,392	5,781	5,108	4,443	7,065	3,814	48,173
50	MARKET OFF PEAK ENERGY	2,850	4,351	3,377	4,445	5,223	6,272	6,551	7,320	5,815	7,661	6,544	2,983	63,392
51	PURCHASED (NUGs) ENERGY	30,489	27,219	32,035	28,114	28,391	25,209	32,957	28,834	25,121	25,324	21,579	21,597	326,871
52	CASE NO. U-16048 COST RECOVERY	1,190	1,190	1,190	1,190	1,190	480	618	563	478	530	520	528	9,669
53	TOTAL EXPENSE	37,062	35,932	38,641	35,242	37,550	36,550	45,519	42,498	36,523	37,958	35,708	28,921	448,104
	NET INTERCHANGE CREDIT ($*1000)													
54	EXTERNAL SALE ENERGY	5,856	5,848	7,031	9,204	9,257	6,766	12,180	7,155	4,210	2,235	2,020	5,954	77,716
55	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
56	MISO RAC	0	0	0	0	0	1	2,295	209	0	0	0	0	2,506
57	TOTAL CREDIT	5,856	5,848	7,031	9,204	9,257	6,767	14,475	7,365	4,210	2,235	2,020	5,954	80,222
58	NET EXPENSE	31,205	30,084	31,610	26,038	28,293	29,783	31,044	35,134	32,313	35,723	33,688	22,967	367,882

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20134
Exhibit No.: A-34 (RTB-2)

Witness: RTBlumenstock
Date: May 2018

Karn 3 and 4 Reliability Improvement

(a) Line No.	(b) Description	(c) 2018	(d) 2019	(e) 2020	(f) 2021	(g) 2022	(h) 2023	(i) 2024	(j) 2025	(k) 2026	(l) 2027	(m) 2028	(n) 2029	(o) 2030	Calculation /Source
	Forecasted Test Capacity (MW)														
1	Karn 3	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	Planning Year 2018 GVTC Test Result
2	Karn 4	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	603.0	Planning Year 2018 GVTC Test Result
	Requested Reliability Capital Spend ($)														
3	Karn 3&4	$ 4,687,000	$ 6,900,000	$ 5,500,000	$ 5,200,000	$ 3,092,000	$ 5,075,800	$ 5,075,800	$ 5,075,800	$ 5,075,800	$ 5,075,800	$ 5,075,800	$ 5,075,800	$ 5,075,800	2018 - 2022: CE Generation Engineering, 2024 + average of 2019 - 2023
	EFORd Forecast (%) w/o Capital Spend														
4	Karn 3	23.49%	34.42%	45.35%	56.28%	67.21%	78.14%	89.07%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	Linear interpolation from 2018 to unit not functionally operational in 5 years (beginning 1/1/2024)
5	Karn 4	37.70%	46.60%	55.50%	64.40%	73.30%	82.20%	91.10%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	Linear interpolation from 2018 to unit not functionally operational in 5 years (beginning 1/1/2024)
	Capacity Forecast (ZRC) w/o Capital Spend														
6	Karn 3	459.0	393.5	327.9	262.3	196.7	131.2	65.6	0.0	0.0	0.0	0.0	0.0	0.0	Line 1 * (1 - Line 4)
7	Karn 4	375.7	322.0	268.4	214.7	161.0	107.3	53.7	0.0	0.0	0.0	0.0	0.0	0.0	Line 2 * (1 - Line 5)
8	Sum	834.7	715.5	596.3	477.0	357.7	238.5	119.3	0.0	0.0	0.0	0.0	0.0	0.0	Line 6 + Line 7
	EFORd Forecast (%) w/ Capital Spend														
9	Karn 3	23.49%	26.20%	21.06%	23.73%	19.97%	20.01%	20.03%	20.17%	19.67%	19.29%	19.05%	19.09%	19.06%	EFORd forecast with 1/1/06 - 1/31/18 averages
10	Karn 4	37.70%	30.90%	27.53%	17.41%	17.35%	17.30%	17.10%	16.61%	16.11%	15.77%	15.80%	15.77%	15.81%	EFORd forecast with 1/1/06 - 1/31/18 averages
	Capacity Forecast (ZRC) w/ Capital Spend														
11	Karn 3	459.0	442.8	473.6	457.6	480.2	479.9	479.8	479.0	482.0	484.3	485.7	485.5	485.6	Line 1 * (1 - Line 9)
12	Karn 4	375.7	416.7	437.0	498.0	498.4	498.7	499.9	502.8	505.8	507.9	507.7	507.9	507.6	Line 2 * (1 - Line 10)
13	Sum	834.7	859.5	910.6	955.6	978.6	978.6	979.7	981.8	987.8	992.2	993.4	993.4	993.2	Line 11 + Line 12
	Forecasted Capacity Improvement (ZRC)														
14	Karn 3&4	-	144.0	314.3	478.6	620.9	740.1	860.4	981.8	987.8	992.2	993.4	993.4	993.2	Line 13 - Line 8
15	Forecasted Capacity Price ($/ZRC-yr)	$ 68,055	$ 69,416	$ 70,804	$ 72,221	$ 73,665	$ 75,138	$ 76,641	$ 78,174	$ 79,737	$ 81,332	$ 82,959	$ 84,618	$ 86,310	75% of CONE in 2018 escalated at 2%
	Forecasted Value of Capacity Improvement ($)														
16	Karn 3&4	$ -	$ 9,995,918	$ 22,253,830	$ 34,564,736	$ 45,738,549	$ 55,609,796	$ 65,941,902	$ 76,751,040	$ 78,764,484	$ 80,697,635	$ 82,411,138	$ 84,059,361	$ 85,723,286	Line 14 * Line 15

Years	NPV of Capital Spend (2018$)	NPV of Value of Capacity Improvement (2018$)	NPV of Value of Capacity Improvement - Capital Spend (2018$)
2018 - 2022	$20,779,613	$84,149,825	$63,370,212
2018 - 2025	$29,944,339	$202,574,762	$172,630,424
2018 - 2028	$37,311,297	$319,463,731	$282,152,434
2018 - 2030	$41,401,000	$387,838,487	$346,437,487

CSXT Rate Complaint -
Litigation Expense, Estimated Reparations, and Forecasted Savings

Consumers Energy Company
STB Case No. 42012
PSCR Savings
2015 - 2024
CE Only

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Year**	**Litigation Expense**	**2015 - 2017 Reparations**	**PSCR Fuel Expense Reduction**	**Total Savings**	**Cumulative Total**
1	2015	$3,380,971			($3,380,971)	($3,252,045)
2	2016	$2,724,700			($2,724,700)	($6,105,672)
3	2017	$767,393			($767,393)	($6,873,065)
4	2018	$726,582	$7,966,779	$3,641,507	$10,881,704	$4,008,639
5	2019			$4,826,300	$4,826,300	$8,834,940
6	2020			$8,281,153	$8,281,153	$17,116,092
7	2021			$7,504,238	$7,504,238	$24,620,330
8	2022			$10,131,705	$10,131,705	$34,752,035
9	2023			$7,247,018	$7,247,018	$41,999,053
10	2024			$13,554,259	$13,554,259	$55,553,312
11	**Total**	**$7,599,647**	**$7,966,779**	**$55,186,180**	**$55,553,312**	

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20134

EXHIBITS

OF

ANDREW J. BORDINE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Schedule B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION	Case No.: U-20134
Consumers Energy Company	Exhibit No.: A-12 (AJB-1)
Projected Capital Expenditures	Schedule: B-5.4
Electric Distribution	Page: 1 of 3
Summary of Actual and Projected Electric Capital Expenditures	Witness: AJBordine
($000)	Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	New Business Program	96,540	94,634	98,065	192,699	98,065
	Contractor	6,767	6,570	6,871	13,441	6,871
	Labor	16,121	15,651	16,368	32,020	16,368
	Materials	25,659	24,910	26,052	50,962	26,052
	Business Expenses	23	23	24	46	24
	Contingency	-	909	45	954	45
	Other (Loadings, Chargebacks)	47,969	46,570	48,704	95,275	48,704
2	Reliability Program	110,946	178,553	227,134	405,687	227,134
	Contractor	28,348	45,450	57,816	103,265	57,816
	Labor	9,055	14,517	18,467	32,985	18,467
	Materials	19,442	31,170	39,651	70,821	39,651
	Business Expenses	4,631	7,425	9,445	16,871	9,445
	Contingency	-	678	-	678	-
	Other (Loadings, Chargebacks)	49,469	79,312	100,892	180,204	100,892
3	Capacity Program	53,461	51,091	56,793	107,884	56,793
	Contractor	13,208	12,384	14,031	26,416	14,031
	Labor	5,168	4,846	5,490	10,336	5,490
	Materials	11,994	11,246	12,742	23,988	12,742
	Business Expenses	69	65	73	138	73
	Contingency	-	964	-	964	-
	Other (Loadings, Chargebacks)	23,022	21,586	24,457	46,043	24,457
4	Demand Failures Program	155,857	145,460	151,826	297,286	151,826
	Contractor	24,136	22,464	23,512	45,976	23,512
	Labor	22,482	20,925	21,900	42,825	21,900
	Materials	35,171	32,735	34,261	66,996	34,261
	Business Expenses	420	391	409	801	409
	Contingency	-	398	-	398	-
	Other (Loadings, Chargebacks)	73,647	68,546	71,742	140,289	71,742
5	Asset Relocation Program	28,113	27,298	24,051	51,349	24,051
	Contractor	6,587	6,333	5,635	11,968	5,635
	Labor	4,197	4,036	3,591	7,626	3,591
	Materials	3,777	3,631	3,231	6,863	3,231
	Business Expenses	6	6	5	12	5
	Contingency	-	269	-	269	-
	Other (Loadings, Chargebacks)	13,544	13,022	11,587	24,610	11,587
6	Electric Operations Other Program	2,958	10,155	10,854	21,009	10,854
	Contractor	141	484	517	1,001	517
	Labor	2	7	7	14	7
	Materials	2,769	9,506	10,160	19,667	10,160
	Business Expenses	2	7	7	14	7
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	44	151	161	313	161
7	**Total Capital**	447,875	507,191	568,723	1,075,914	568,723

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Electric Distribution
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-36 (AJB-2)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
Line No.	**Description**	**Historical 12 Mos Ended 12/31/2017**	**U-18322 Approved ($) 12 Mos Ending 9/30/2018**	**U-18322 Projected ($) 12 Mos Ending 9/30/2018**	**U-18322 Approved vs Actual Variation (%)***	**Location of Testimony Regarding Variation > 10%***	**Projected Test Year 12 Mos Ending 12/31/2019**
1	New Business	96,540	78,388	102,060	n/a	n/a	98,065
2	Reliability	110,945	129,174	154,731	n/a	n/a	227,134
3	Capacity	53,461	49,874	58,949	n/a	n/a	56,793
4	Demand Failures	155,857	121,381	146,795	n/a	n/a	151,826
5	Asset Relocation	28,113	20,204	29,853	n/a	n/a	24,051
6	Electric Operations Other	2,957	3,666	6,376	n/a	n/a	10,854
10	**Total Capital**	447,873	402,687	498,764	n/a		568,723

*Columns (e) and (f) do not contain the comparison of the actual amounts for 12 months ended September 30, 2018 to the amounts approved in Case No. U-18322 because as of this filing the 12 months ending September 30, 2018 has not been completed so the explanations and variance cannot be calculated at this time.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Electric Distribution Program/Sub-Program
($000)

Case No.: U-20134
Exhibit No.: A-37 (AJB-3)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

Line No.	(a) Rate Case Program / Sub-Program	(b) EDIIP Filing Program / Sub-Program	(c) 2019 EDIIP Filing	(d) 2019 Projected Test Year	(e) Witness
1	LVD Lines New Business	1.1 Lines New Business - LVD	64,803	64,803	AJBordine
2	Large New Business Projects	-	-	0	AJBordine
3	HVD New Business	1.2 Lines Strategic Customers - HVD	10,000	10,000	JRAnderson
4	Distribution Metering New Business	1.4 Metering New Business - LVD	6,790	6,790	AJBordine
5	Distribution Transformers New Business	1.5 Transformers New Business - LVD	11,696	11,696	AJBordine
6	Metro New Business	1.3 Metro New Business	4,776	4,776	AJBordine
7	**New Business**	**1.0 New Business**	**98,065**	**98,065**	
8	LVD Lines Reliability	4.1 Lines Reliability - LVD	49,406	49,406	AJBordine
9	HVD Lines Reliability	4.2 Lines Reliability - HVD	38,837	38,837	JRAnderson
10	LVD Substations Reliability	4.3 Substations Reliability - LVD	20,202	20,202	JRAnderson
11	HVD Substation Reliability	4.4 Substations Reliability - HVD	4,879	4,879	JRAnderson
12	HVD System Protection	4.6 System Protection	2,325	2,325	JRAnderson
13	LVD Repetitive Outages	4.7 Repetitive Outages - LVD	9,293	9,293	AJBordine
14	Metro Reliability	4.8 Metro Reliability	3,140	3,140	AJBordine
15	Substations Communications Upgrades	4.5 Substations Communications Upgrades	41,000	41,000	JRAnderson
16	Grid Capabilities: Automation	4.9 Grid Capabilities: Automation	30,592	30,592	AJBordine
17	Grid Capabilities: Advanced Technologies	4.10 Grid Capabilities: Advanced Tech	32,460	27,460	AJBordine
18	**Reliability**	**4.0 Reliability**	**232,134**	**227,134**	
19	LVD Lines Capacity	5.1 Lines Capacity - LVD	17,329	17,329	AJBordine
20	HVD Lines & Substations Capacity	5.2 Lines & Subs Capacity - HVD	22,188	22,188	JRAnderson
21	LVD Substations Capacity	5.3 Substations Capacity - LVD	13,148	13,148	JRAnderson
22	LVD Transformers Capacity	5.4 Transformers Capacity - LVD	4,128	4,128	AJBordine
23	**Capacity**	**5.0 Capacity**	**56,793**	**56,793**	
24	LVD Lines Demand Failures	2.1 Lines Failures - LVD	79,000	79,000	AJBordine
25	HVD Lines & Substations Failures	2.3 Lines & Subs Failures - HVD	16,849	16,849	JRAnderson
26	LVD Substations Failures	2.2 Substations Failures - LVD	13,823	13,823	JRAnderson
27	Distribution Metering Failures	2.4 Metering Failures - LVD	12,584	12,584	AJBordine
28	Distribution Transformers Failures	2.5 Transformers Failures - LVD	18,576	18,576	AJBordine
29	Streetlight - Mercury Vapor	2.6 Streetlighting	6,127	6,127	AJBordine
30	Metro Demand Failures	2.7 Metro Failures	4,867	4,867	AJBordine
31	**Demand Failures**	**2.0 Demand Failures**	**151,826**	**151,826**	
32	LVD Asset Relocations	3.1 Lines Relocations - LVD	20,063	20,063	AJBordine
33	HVD Asset Relocations	3.2 Lines Relocations - HVD	848	848	JRAnderson
34	Metro Asset Relocations	3.3 Metro Relocations	3,140	3,140	AJBordine
35	**Asset Relocations**	**3.0 Asset Relocations**	**24,051**	**24,051**	
36	Computer & Equipment	6.0 Tools and Technology	270	270	JRAnderson
37	Capital Tools	6.0 Tools and Technology	5,216	5,216	AJBordine
38	System Control Projects	6.0 Tools and Technology	2050	2050	JRAnderson
39	NERC/NESC Compliance	6.0 Tools and Technology	3160	3160	JRAnderson
40	Substation Fall Protection	6.0 Tools and Technology	158	158	JRAnderson
41	**Electric Operations Other**	**6.0 Tools and Technology**	**10,854**	**10,854**	
42	**-**	**7.0 Cost of Removals**	**61,594**	**-**	
43	**Total**		**635,317**	**568,723**	

44 The EDIIP filing included $5,000,000 more than the projected test year in sub-program "4.10 Grid Capabilities: Advanced Tech" for strategic initiatives.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Electric Distribution
Summary of 5yr Historical Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-38 (AJB-4)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

Line No.	(a) Program / Sub-Program	(b) Witness	(c) 2013 Actuals	(d) 2014 Actuals	(e) 2015 Actuals	(f) 2016 Actuals	(g) 2017 Actuals	(h) 5yr Average	(i) 2018 Projected Bridge Year	(j) 2019 Projected Test Year	(k) Test Year vs 5yr Ave Variance (j - h)
1	LVD Lines New Business	AJBordine	28,604	40,058	45,644	43,039	65,878	44,645	59,938	64,803	20,158
2	Large New Business Projects	AJBordine	0	680	29	-37	0	134	0	0	-134
3	HVD Strategic Cust. New Business	JRAnderson	5,496	8,213	7,035	27,864	7,113	11,144	13,572	10,000	-1,144
4	Distribution Metering New Business	AJBordine	3,439	2,745	5,171	5,266	8,075	4,939	5,938	6,790	1,851
5	Distribution Transformers New Business	AJBordine	7,020	8,306	12,136	8,852	13,063	9,875	9,848	11,696	1,821
6	Metro New Business	AJBordine	3,691	2,700	2,760	3,243	2,411	2,961	5,338	4,776	1,815
7	**New Business**		**48,250**	**62,702**	**72,775**	**88,227**	**96,540**	**73,699**	**94,634**	**98,065**	**24,366**
8	LVD Lines Reliability	AJBordine	36,329	48,215	25,092	48,617	37,877	39,226	45,840	49,406	10,180
9	HVD Lines Reliability	JRAnderson	17,703	26,702	14,640	37,825	17,325	22,839	36,672	38,837	15,998
10	LVD Substations Reliability	JRAnderson	13,898	6,780	8,936	11,135	14,112	10,972	19,273	20,202	9,230
11	HVD Subs Reliability	JRAnderson	5,672	2,021	3,458	3,850	4,342	3,869	3,765	4,879	1,010
12	HVD System Protection	JRAnderson	1,334	2,372	1,899	1,569	4,244	2,284	1,976	2,325	41
13	LVD Repetitive Outages	AJBordine	18,823	16,086	10,322	8,353	6,270	11,971	9,684	9,293	-2,678
14	Metro Reliability	AJBordine	3,649	1,755	4,209	2,518	949	2,616	3,524	3,140	524
15	Substations Comm Upgrades	JRAnderson	0	10	508	1,324	11,903	2,749	23,000	41,000	38,251
16	Grid Capabilities: Automation	AJBordine	4,297	9,216	13,758	17,601	13,924	11,759	24,307	30,592	18,833
17	Grid Capabilities: Advanced Technologies	AJBordine	0	0	0	0	0	0	10,512	27,460	27,460
18	**Reliability**		**101,705**	**113,157**	**82,822**	**132,792**	**110,946**	**108,284**	**178,553**	**227,134**	**118,850**
19	LVD Lines Capacity	AJBordine	12,403	13,608	16,871	14,517	18,332	15,146	17,970	17,329	2,183
20	HVD Lines & Subs Capacity	JRAnderson	9,308	13,596	15,612	20,965	16,823	15,261	17,814	22,188	6,927
21	LVD Substations Capacity	JRAnderson	9,768	10,927	7,209	18,044	13,696	11,929	11,831	13,148	1,219
22	LVD Transformers Capacity	AJBordine	8,616	3,692	3,944	3,219	4,610	4,816	3,476	4,128	-688
23	**Capacity**		**40,095**	**41,823**	**43,636**	**56,745**	**53,461**	**47,152**	**51,091**	**56,793**	**9,641**
24	LVD Lines Dem Failures	AJBordine	64,995	47,674	76,151	66,860	84,508	68,038	78,785	79,000	10,962
25	HVD Lines and Substations Failures	JRAnderson	12,132	11,688	14,877	13,206	17,623	13,905	15,889	16,849	2,944
26	LVD Substations Failures	JRAnderson	8,369	11,125	7,613	9,399	15,451	10,391	13,578	13,823	3,432
27	Distribution Metering Failures	AJBordine	6,120	3,021	5,719	7,272	11,805	6,787	11,014	12,584	5,797
28	Distribution Transformers Failures	AJBordine	16,274	18,766	14,260	14,754	20,747	16,960	15,641	18,576	1,616
29	Streetlight - Mercury Vapor	AJBordine	2,698	2,877	2,701	2,193	2,080	2,510	6,206	6,127	3,617
30	Metro Demand Failures	AJBordine	2,118	1,970	1,517	5,047	3,643	2,859	4,347	4,867	2,008
31	**Demand Failures**		**112,706**	**97,121**	**122,838**	**118,731**	**155,857**	**121,451**	**145,460**	**151,826**	**30,375**
32	LVD Asset Relocations	AJBordine	12,644	16,712	19,368	14,362	23,154	17,248	16,778	20,063	2,815
33	HVD Asset Relocations	JRAnderson	-61	364	1,056	288	168	363	601	848	485
34	Metro Asset Relocations	AJBordine	2,823	2,338	7,325	4,854	4,791	4,426	9,919	3,140	-1,286
35	**Asset Relocations**		**15,406**	**19,414**	**27,749**	**19,504**	**28,113**	**22,037**	**27,298**	**24,051**	**2,014**
36	Computer & Equipment	JRAnderson	282	393	113	76	430	258.8	260	270	11
37	Capital Tools	AJBordine	1,094	2,305	2,178	3,377	1,903	2,171	5,125	5,216	3,045
38	System Control Projects	JRAnderson	280	174	88	2	619	232.6	1700	2050	1,817
39	NERC/NESC Compliance	JRAnderson	0	0	0	0	0	0	2920	3160	3,160
40	Substation Fall Protection	JRAnderson	523	251	196	80	6	211.2	150	158	-53
41	**Electric Operations Other**		**2,179**	**3,123**	**2,575**	**3,535**	**2,958**	**2,874**	**10,155**	**10,854**	**7,980**
42	**Total Capital - Loaded**		**320,341**	**337,340**	**352,395**	**419,534**	**447,875**	**375,497**	**507,191**	**568,723**	**193,226**

Schedule B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Low Voltage Distribution (LVD)
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-12 (AJB-5)
Schedule: B-5.4

Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Description	12 Mos Ended 12/31/2017	12 Mos Ending 12/31/2018	12 Mos Ending 12/31/2019	24 Mos Ending 12/31/2019	12 Mos Ending 12/31/2019
1	New Business Program	89,427	81,062	88,065	169,127	88,065
	Contractor	4,450	4,034	4,382	8,416	4,382
	Labor	15,455	14,009	15,219	29,228	15,219
	Materials	22,098	20,031	21,761	41,792	21,761
	Business Expenses	17	16	17	33	17
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	47,407	42,972	46,685	89,657	46,685
2	Reliability Program	59,020	93,867	119,891	213,758	119,891
	Contractor	10,138	16,063	20,595	36,658	20,595
	Labor	5,943	9,416	12,072	21,489	12,072
	Materials	6,932	10,984	14,082	25,066	14,082
	Business Expenses	4,615	7,313	9,376	16,688	9,376
	Contingency	-	354	-	354	-
	Other (Loadings, Chargebacks)	31,391	49,736	63,766	113,502	63,766
3	Capacity Program	22,942	21,446	21,457	42,903	21,457
	Contractor	3,620	3,366	3,386	6,751	3,386
	Labor	2,730	2,538	2,554	5,092	2,554
	Materials	4,672	4,344	4,370	8,713	4,370
	Business Expenses	5	5	5	10	5
	Contingency	-	117	-	117	-
	Other (Loadings, Chargebacks)	11,915	11,077	11,143	22,220	11,143
4	Demand Failures Program	122,783	115,993	121,154	237,147	121,154
	Contractor	16,225	15,327	16,009	31,337	16,009
	Labor	19,707	18,617	19,445	38,062	19,445
	Materials	24,718	23,351	24,390	47,741	24,390
	Business Expenses	411	389	406	794	406
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	61,722	58,309	60,904	119,213	60,904
5	Asset Relocation Program	27,945	26,697	23,203	49,900	23,203
	Contractor	6,313	5,970	5,242	11,212	5,242
	Labor	4,170	3,944	3,462	7,406	3,462
	Materials	3,654	3,456	3,034	6,490	3,034
	Business Expenses	6	6	5	11	5
	Contingency	-	269	-	269	-
	Other (Loadings, Chargebacks)	13,801	13,052	11,459	24,511	11,459
6	Electric Operations Other Program	1,903	5,125	5,216	10,341	5,216
	Contractor	-	-	-	-	-
	Labor	0	1	1	2	1
	Materials	1,903	5,125	5,216	10,340	5,216
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	0	0	0	1	0
7	**Total Capital**	324,021	344,190	378,986	723,176	378,986

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Low Voltage Distribution (LVD)
Summary of 5yr Historical Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-39 (AJB-6)

Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Program / Sub-Program	Witness	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	5yr Average	2018 Projected Bridge Year	2019 Projected Test Year	Test Year vs 5yr Ave Variance (j - h)
1	LVD Lines New Business	AJBordine	28,604	40,058	45,644	43,039	65,878	44,645	59,938	64,803	20,158
2	Large New Business Projects	AJBordine	0	680	29	-37	0	134	0	0	-134
3	Distribution Metering New Business	AJBordine	3,439	2,745	5,171	5,266	8,075	4,939	5,938	6,790	1,851
4	Distribution Transformers New Business	AJBordine	7,020	8,306	12,136	8,852	13,063	9,875	9,848	11,696	1,821
5	Metro New Business	AJBordine	3,691	2,700	2,760	3,243	2,411	2,961	5,338	4,776	1,815
6	**New Business**		**42,754**	**54,489**	**65,740**	**60,363**	**89,427**	**62,555**	**81,062**	**88,065**	**25,510**
7	LVD Lines Reliability	AJBordine	36,329	48,215	25,092	48,617	37,877	39,226	45,840	49,406	10,180
8	LVD Repetitive Outages	AJBordine	18,823	16,086	10,322	8,353	6,270	11,971	9,684	9,293	-2,678
9	Metro Reliability	AJBordine	3,649	1,755	4,209	2,518	949	2,616	3,524	3,140	524
10	Grid Capabilities: Automation	AJBordine	4,297	9,216	13,758	17,601	13,924	11,759	24,307	30,592	18,833
11	Grid Capabilities: Advanced Technologies	AJBordine	0	0	0	0	0	0	10,512	27,460	27,460
12	**Reliability**		**63,098**	**75,272**	**53,381**	**77,089**	**59,020**	**65,572**	**93,867**	**119,891**	**54,319**
13	LVD Lines Capacity	AJBordine	12,403	13,608	16,871	14,517	18,332	15,146	17,970	17,329	2,183
14	LVD Transformers Capacity	AJBordine	8,616	3,692	3,944	3,219	4,610	4,816	3,476	4,128	-688
15	**Capacity**		**21,019**	**17,300**	**20,815**	**17,736**	**22,942**	**19,962**	**21,446**	**21,457**	**1,495**
16	LVD Lines Demand Failures	AJBordine	64,995	47,674	76,151	66,860	84,508	68,038	78,785	79,000	10,962
17	Distribution Metering Failures	AJBordine	6,120	3,021	5,719	7,272	11,805	6,787	11,014	12,584	5,797
18	Distribution Transformers Failures	AJBordine	16,274	18,766	14,260	14,754	20,747	16,960	15,641	18,576	1,616
19	Streetlight - Mercury Vapor	AJBordine	2,698	2,877	2,701	2,193	2,080	2,510	6,206	6,127	3,617
20	Metro Demand Failures	AJBordine	2,118	1,970	1,517	5,047	3,643	2,859	4,347	4,867	2,008
21	**Demand Failures**		**92,205**	**74,308**	**100,348**	**96,126**	**122,783**	**97,154**	**115,993**	**121,154**	**24,000**
22	LVD Asset Relocations	AJBordine	12,644	16,712	19,368	14,362	23,154	17,248	16,778	20,063	2,815
23	Metro Asset Relocations	AJBordine	2,823	2,338	7,325	4,854	4,791	4,426	9,919	3,140	-1,286
24	**Asset Relocations**		**15,467**	**19,050**	**26,693**	**19,216**	**27,945**	**21,674**	**26,697**	**23,203**	**1,529**
25	Capital Tools	AJBordine	1,094	2,305	2,178	3,377	1,903	2,171	5,125	5,216	3,045
26	**Electric Operations Other**		**1,094**	**2,305**	**2,178**	**3,377**	**1,903**	**2,171**	**5,125**	**5,216**	**3,045**
27	**Total Capital - Loaded**		**235,637**	**242,724**	**269,155**	**273,907**	**324,020**	**269,089**	**344,190**	**378,986**	**109,897**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
LVD New Business Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-40 (AJB-7)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	LVD Lines New Business	65,878	59,938	64,803	124,741	64,803
	Contractor	3,874	3,525	3,811	7,336	3,811
	Labor	11,119	10,116	10,937	21,053	10,937
	Materials	11,926	10,851	11,731	22,582	11,731
	Business Expenses	12	11	12	23	12
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	38,946	35,435	38,311	73,746	38,311
2	Distribution Metering New Business	8,075	5,938	6,790	12,728	6,790
	Contractor		-	-	-	-
	Labor	1,333	980	1,121	2,101	1,121
	Materials	3,920	2,883	3,296	6,179	3,296
	Business Expenses	0	0	0	0	0
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	2,822	2,075	2,373	4,448	2,373
3	Distribution Transformers New Business	13,063	9,848	11,696	21,544	11,696
	Contractor	3	2	2	4	2
	Labor	2,741	2,067	2,454	4,521	2,454
	Materials	5,537	4,175	4,958	9,132	4,958
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	4,782	3,605	4,281	7,886	4,281
4	Metro New Business	2,411	5,338	4,776	10,114	4,776
	Contractor	573	1,269	1,135	2,404	1,135
	Labor	262	580	519	1,099	519
	Materials	714	1,582	1,415	2,997	1,415
	Business Expenses	5	11	10	21	10
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	856	1,896	1,697	3,593	1,697
5	**Total Capital**	89,427	81,062	88,065	169,127	88,065

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
LVD Reliability Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-41 (AJB-8)

Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	LVD Lines Reliability	37,877	45,840	49,406	95,246	49,406
	Contractor	8,793	10,642	11,469	22,111	11,469
	Labor	3,082	3,729	4,020	7,749	4,020
	Materials	4,567	5,527	5,957	11,484	5,957
	Business Expenses	63	76	82	159	82
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	21,372	25,865	27,878	53,743	27,878
2	LVD Repetitive Outages	6,270	9,684	9,293	18,977	9,293
	Contractor	1,068	1,649	1,582	3,231	1,582
	Labor	693	1,071	1,028	2,099	1,028
	Materials	737	1,139	1,093	2,231	1,093
	Business Expenses	20	31	29	60	29
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	3,752	5,795	5,561	11,356	5,561
3	Metro Reliability	949	3,524	3,140	6,664	3,140
	Contractor	275	1,020	909	1,929	909
	Labor	64	236	210	446	210
	Materials	255	948	844	1,792	844
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	355	1,320	1,177	2,497	1,177
4	Grid Capabilities: Automation	13,924	24,307	30,592	54,899	30,592
	Contractor	3	5,561	7,102	12,662	7,102
	Labor	2,104	1,949	2,489	4,438	2,489
	Materials	1,373	2,888	3,689	6,577	3,689
	Business Expenses	4,533	40	51	91	51
	Contingency	-	354	-	354	-
	Other (Loadings, Chargebacks)	5,911	13,515	17,262	30,777	17,262
5	Grid Capabilities: Advanced Technologies	-	10,512	27,460	37,972	27,460
	Contractor	-	10,512	9,886	20,398	9,886
	Labor	-	-	2,334	2,334	2,334
	Materials	-	-	6,590	6,590	6,590
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	8,650	8,650	8,650
6	**Total Capital**	59,020	93,867	119,891	213,758	119,891

($000)

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2019 Test Year	(d) Description	(e) Work Description	(f) Investment Category
1	LVD Lines Reliability	Pole Inspection - Replace red tagged poles	$ 19,220	Pole Inspection - Replace red tagged poles	3750 Approximate Poles Replaced	POLE
		First Zone	$ 14,442	First Zone	Complete 83 worst performing First Zones	First Zone
		Sub Related Line Work	$ 2,958	Sub Related Line Work	Complete 6 substation driven reliability projects	SUB - RLBY
		Targeted Worst Zones	$ 11,426	Targeted Worst Zones	Complete 66 Targeted Worst Zones	Targeted Worst Zones
		Circuit Exit Switch Installation	$ 892	Circuit Exit Switch Installation	35 Exit Switches	Not Listed
		Customer Committed/High Publicity	$ 469	Customer Committed/High Publicity	Complete 2 customer committed projects	Customer Committed
		LVD Lines Reliability Total	$ 49,407			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Low Voltage Distribution (LVD) Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-41 (AJB-8)

Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)
Line No.	Category	Feeder ID	Substation	Circuit
1	Customer Committed	037101	DELTON	CLOVERDALE
2	Customer Committed	100801	HARRIETTA	CABERFAE
3	First Zone	103501	KNAPP	DEAN LK
4	First Zone	104201	ROGUE RIVER	CANNON FARMS
5	First Zone	107201	ALAMO	FISH HATCH
6	First Zone	107202	ALAMO	PINE GROVE
7	First Zone	112001	HOGSBACK	CEDAR STREET
8	First Zone	112602	CASCADE	CASCADE
9	First Zone	121701	FROST	LONG LAKE
10	First Zone	124205	BRETON	TOWERS
11	First Zone	126702	TAMARACK	LAKEVIEW
12	First Zone	127001	RANGER LAKE	KOKOSING
13	First Zone	127301	WHITTEMORE	M-65
14	First Zone	127302	WHITTEMORE	SAND LAKE
15	First Zone	127602	COTTAGE GROVE	HURON
16	First Zone	133901	WATKINS	CHRISTY
17	First Zone	134002	ALDER CREEK	EAST LEROY
18	First Zone	138302	MILL GROVE	ALG HYDRO
19	First Zone	140401	ALGER	SKIDWAY
20	First Zone	142701	IRISH ROAD	BELLE MEAD
21	First Zone	147601	VAN ATTA	POWELL
22	First Zone	149601	CLEAR LAKE	WATERLOO
23	First Zone	151903	HILL ROAD	PINE WAY
24	First Zone	155501	WOODWARD	WOODWARD LAKE
25	First Zone	159502	PEARLINE	WINDFIELD
26	First Zone	000403	COLEMAN	COLEMAN
27	First Zone	000601	SHEPHERD	SHEPHERD
28	First Zone	000704	MUSKEGON HEIGHTS	HEIGHTS
29	First Zone	002001	GREENWOOD	RAU ROAD
30	First Zone	003502	CADILLAC	HOSPITAL
31	First Zone	003506	CADILLAC	BERRY LAKE
32	First Zone	004703	SPRING DRIVE	BISHOP LAKE
33	First Zone	004801	PARMA	PARMA
34	First Zone	005401	STANLEY	SUMMIT
35	First Zone	010001	WEALTHY STREET	NORTHWEST
36	First Zone	010007	WEALTHY STREET	GODFREY
37	First Zone	024102	DOEHLER JARVIS	GRIGGS STREET
38	First Zone	024404	PORTAGE	LOVERSLANE
39	First Zone	024802	EASTON	HAYNOR
40	First Zone	025202	ONEKAMA	BEAR LAKE
41	First Zone	025501	SALEM	BURNIPS
42	First Zone	028302	CEDAR SPRINGS	EDGERTON
43	First Zone	028303	CEDAR SPRINGS	WHITECREEK
44	First Zone	029203	MANCHESTER	MANCHESTER
45	First Zone	029302	MARKEY	CARRICK
46	First Zone	030302	JOPPA	JOPPA
47	First Zone	032404	HOWARD CITY	CORAL
48	First Zone	034402	HULL STREET	CRANBERRY
49	First Zone	034602	BYRON CENTER	CARLISLE
50	First Zone	036402	IRON STREET	ATHERTON
51	First Zone	036404	IRON STREET	JOYCE
52	First Zone	037602	BATTEESE	PLEASANT LAKE
53	First Zone	041604	WHITTUM	PETRIEVILLE
54	First Zone	043301	FOUR MILE	GREENRIDGE
55	First Zone	047501	BECKER	BEAR CREEK
56	First Zone	049202	HASKELITE	RICHMOND
57	First Zone	049905	STANDALE	PARKSIDE
58	First Zone	050202	WYOMING PARK	PORTER
59	First Zone	051601	BRADFORD	DISTRIBUTION
60	First Zone	053802	COURT	KENT
61	First Zone	054602	ALDEN	CLAM
62	First Zone	056801	RAMONA	ROBINSON
63	First Zone	057001	COLON	COLON
64	First Zone	058601	LEITH STREET	FRANKLIN
65	First Zone	058801	CHICAGO	CHICAGO
66	First Zone	058902	THORNAPPLE	BUTTRICK
67	First Zone	059901	HEMLOCK	NELSON
68	First Zone	061601	PRINCETON	WATTLES
69	First Zone	061702	FRANKFORT	CRYSTALLIA
70	First Zone	062901	COOPERSVILLE	CONKLIN
71	First Zone	063602	LAKE CITY	STITTSVILL
72	First Zone	064705	MAYFAIR	PIERSON
73	First Zone	065401	BISHOP	RAINBOW
74	First Zone	066402	TRAVIS	COLLINGWD
75	First Zone	068603	PARKWAY	VINE
76	First Zone	071203	COLLEGE PARK	RIVERSIDE

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Low Voltage Distribution (LVD) Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-41 (AJB-8)
Page: 4 of 6
Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)
Line No.	Category	Feeder ID	Substation	Circuit
#REF!	First Zone	072402	THAYER	LUFKIN
#REF!	First Zone	075702	MAPLE GROVE	SUMMIT AVE
#REF!	First Zone	075901	REYNOLDS	REYNOLDS
#REF!	First Zone	082501	NORTHERN FIBRE	FIBRE
#REF!	First Zone	087202	CALEDONIA	CALEDONIA
#REF!	First Zone	090601	HARRIET	WITHERBEE
#REF!	First Zone	093404	CALVIN	WOODCLIFF
#REF!	First Zone	094602	NEWARK	EVANS ROAD
#REF!	First Zone	158202	RYNO	MAPES
#REF!	Pole	000403	COLEMAN	COLEMAN
#REF!	Pole	000602	SHEPHERD	FOREST HILL
#REF!	Pole	000705	MUSKEGON HEIGHTS	MUSKEGON
#REF!	Pole	001402	CERESCO	CERESCO
#REF!	Pole	002502	SUTTONS BAY	SUTTONS BAY
#REF!	Pole	003502	CADILLAC	HOSPITAL
#REF!	Pole	003503	CADILLAC	BOND
#REF!	Pole	003506	CADILLAC	BERRY LAKE
#REF!	Pole	004501	LARKIN	LARKIN
#REF!	Pole	007401	HUDSON	WATER WORKS
#REF!	Pole	008504	ELM STREET	VAN BUREN
#REF!	Pole	014103	GRANDVILLE	GRANDVILLE
#REF!	Pole	017902	STANDISH	STANDISH
#REF!	Pole	018501	PULLMAN	CHICORA
#REF!	Pole	018901	FINE LAKE	BRISTOL
#REF!	Pole	020502	WEST BRANCH	REFINERY
#REF!	Pole	022503	MIDDLETON	NEWARK
#REF!	Pole	023103	MENDON	M-60
#REF!	Pole	023402	NEFF ROAD	DODGE ROAD
#REF!	Pole	024102	DOEHLER JARVIS	GRIGGS STREET
#REF!	Pole	024203	MCBAIN	LUCAS
#REF!	Pole	025302	NASHVILLE	NASHVILLE
#REF!	Pole	026001	SARANAC	KEENE
#REF!	Pole	026401	NORTH LANSING	VALLEY FARMS
#REF!	Pole	026901	OTSEGO	OTSEGO
#REF!	Pole	027803	DIXIE	GEORGE STREET
#REF!	Pole	028901	MILLER ROAD	UTLEY ROAD
#REF!	Pole	028902	MILLER ROAD	YALE ST
#REF!	Pole	029201	MANCHESTER	LOGAN ROAD
#REF!	Pole	029602	VANDERCOOK LAKE	ACKERSON LAKE
#REF!	Pole	029801	PALMYRA	PALMYRA
#REF!	Pole	030101	FREEPORT	BOWNE CENTER
#REF!	Pole	030102	FREEPORT	CARLTON CENTER
#REF!	Pole	030302	JOPPA	JOPPA
#REF!	Pole	031102	LAMOREAUX	LAMOREAUX
#REF!	Pole	031802	EAST MUSKEGON	SHERIDAN
#REF!	Pole	033803	HARRISON	STOCKWELL
#REF!	Pole	034101	POTTER	KIRK
#REF!	Pole	035101	BELSAY	BELSAY
#REF!	Pole	036001	LIBERTY	WASHINGTON
#REF!	Pole	036002	LIBERTY	HAMBLIN
#REF!	Pole	036102	EDDY	FINDLEY
#REF!	Pole	036201	WASHINGTON	FIRST STREET
#REF!	Pole	036404	IRON STREET	JOYCE
#REF!	Pole	036906	COOLEY	EXCHANGE
#REF!	Pole	037101	DELTON	CLOVERDALE
#REF!	Pole	037102	DELTON	DELTON
#REF!	Pole	039302	NIAGARA	HAMILTON
#REF!	Pole	039303	NIAGARA	NIAGARA
#REF!	Pole	039801	SWARTZ CREEK	MORRISH ROAD
#REF!	Pole	040201	WAYLAND	BRADLEY
#REF!	Pole	040301	LONG LAKE	LAKESIDE
#REF!	Pole	041701	GALESBURG	GALESBURG
#REF!	Pole	041901	CONCORD	SWAINS LAKE
#REF!	Pole	042501	KINDERHOOK	LAKE DRIVE
#REF!	Pole	043501	LAKE ODESSA	LAKE
#REF!	Pole	043502	LAKE ODESSA	INDUSTRIAL
#REF!	Pole	048002	PELLSTON	DISTRIBUTION
#REF!	Pole	048501	RODNEY	HORSEHEAD
#REF!	Pole	049701	OLIVET	AINGER
#REF!	Pole	050802	BELDING	MALL
#REF!	Pole	050803	BELDING	COOKS CORNERS
#REF!	Pole	050902	LETTS ROAD	MONROE ROAD
#REF!	Pole	051202	NESTROM	SOUTH SHORE

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Low Voltage Distribution (LVD) Projects
Summary Projected Electric Capital Expenditures
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Case No.: U-20134
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Date: May 2018

	(a)	(b)	(c)	(d)
Line No.	Category	Feeder ID	Substation	Circuit
1	Pole	053801	COURT	WOODLAWN
2	Pole	054404	ORIOLE	BRYANT ROAD
3	Pole	056601	BALDWIN	IDELWILD
4	Pole	056601	BALDWIN	IDLEWILD
5	Pole	057402	PENINSULA	MAPLETON
6	Pole	058202	ENGLISHVILLE	PINE ISLAND
7	Pole	058601	LEITH STREET	FRANKLIN
8	Pole	058604	LEITH STREET	WESTERN ROAD
9	Pole	060102	TUSTIN	LUTHER
10	Pole	060702	GETTY	ALLEN
11	Pole	061302	RIVERDALE	SUMNER
12	Pole	062401	BROOKLYN	FORD
13	Pole	065401	BISHOP	RAINBOW
14	Pole	067404	DEXTER TRAIL	DANSVILLE
15	Pole	071001	MESICK	SHERMAN
16	Pole	072402	THAYER	LUFKIN RULE
17	Pole	075702	MAPLE GROVE	SUMMIT AVENUE
18	Pole	076511	LOVELL	GIBSON
19	Pole	076701	JASPER	JASPER
20	Pole	076702	JASPER	REDSTONE
21	Pole	078601	WESTPHALIA	PRICE ROAD
22	Pole	078602	WESTPHALIA	GRANGE ROAD
23	Pole	079002	SEIDEL	BROCKWAY
24	Pole	081804	ALPINE	ALPINE
25	Pole	082001	FORDYCE	BAMBER
26	Pole	082002	FORDYCE	LINCOLN
27	Pole	082501	NORTHERN FIBRE	FIBRE
28	Pole	084101	LOVEJOY	BRADEN
29	Pole	085702	COCHRAN	SNOW
30	Pole	088203	CARY ROAD	MOSCOW
31	Pole	090101	WAGER	FLINT PARK
32	Pole	090103	WAGER	MARENGO
33	Pole	091501	GRAND VALLEY	TALLMADGE
34	Pole	091901	BESSINGER	QUARRY
35	Pole	093901	LYON MANOR	TREASURE
36	Pole	094602	NEWARK	EVANS ROAD
37	Pole	099602	CENTER ROAD	EASTLAND
38	Pole	102502	ROUND LAKE	ROUND LAKE
39	Pole	104102	GILSON	ROCK LAKE
40	Pole	107604	ISABELLA	REMUS
41	Pole	116501	BENTHEIM	BENTHEIM
42	Pole	117901	SKYLARK	KING'S POINTE
43	Pole	123302	MCKEIGHAN	BRADY ROAD
44	Pole	124501	CEDAR LAKE	KINGS CORNER
45	Pole	125201	UPTON	MT HOPE
46	Pole	125202	UPTON	MARKET PLACE
47	Pole	125203	UPTON	SIMMONS
48	Pole	127402	DUQUITE	JOHNSFIELD
49	Pole	129602	BLACKMAN	HURST
50	Pole	132304	ORCHARD ROAD	ST ANDREWS
51	Pole	134001	ALDER CREEK	LEE LAKE
52	Pole	135903	KIPP ROAD	COLUMBIA ROAD
53	Pole	145102	NOBLE	WHITNEY
54	Pole	147802	JAMES SAVAGE	PATRICK
55	Pole	155402	DUNBAR	HULL ROAD
56	Pole	157602	WEST CLARK LAKE	GRAND
57	SUB - RLBY	TBD	Alcona Dam	New Sub
58	SUB - RLBY	TBD	Five Channels	New Sub
59	SUB - RLBY	TBD	Eight Point 3-6 ckt	New Circuit 3
60	SUB - RLBY	TBD	Ithaca 3-6 & 4-6	New Circuits 3 and 4
61	SUB - RLBY	TBD	Shepherd 3-6	New Circuit 3
62	SUB - RLBY	TBD	Edmore	Cedar Lake
63	Targeted Worst Zones	011003	HASTINGS	BOLTWOOD - LCP 243
64	Targeted Worst Zones	021102	BLACK RIVER	FILLMORE - LCP 643
65	Targeted Worst Zones	023801	LAKE MITCHELL	GOLF CLUB - LCP 6001
66	Targeted Worst Zones	025302	NASHVILLE	NASHVILLE - LCP 422
67	Targeted Worst Zones	025701	OSHTEMO	ALMENA - LCP 576
68	Targeted Worst Zones	026002	SARANAC	CENTERLINE - LCP 668
69	Targeted Worst Zones	027402	CONKLIN PARK	CROTON - LCP 971
70	Targeted Worst Zones	028301	CEDAR SPRINGS	NELSON - LCP 150
71	Targeted Worst Zones	031201	LINCOLN	LOST LAKE - LCP 700
72	Targeted Worst Zones	031702	ABERDEEN	ABERDEEN - LCP 755
73	Targeted Worst Zones	033302	AU GRES	AU GRES - LCP 617

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	(a)	(b)	(c)	(d)
Line No.	**Category**	**Feeder ID**	**Substation**	**Circuit**
1	Targeted Worst Zones	033302	AU GRES	AU GRES - LCP 543
2	Targeted Worst Zones	034402	HULL STREET	CRANBERRY - LCP 604
3	Targeted Worst Zones	034402	HULL STREET	CRANBERRY - LCP 21
4	Targeted Worst Zones	038001	FAIRFIELD	JASPER - LCP 603
5	Targeted Worst Zones	042501	KINDERHOOK	LAKE DRIVE - LCP 681
6	Targeted Worst Zones	042601	PITTSFORD	CHURCH ROAD - LCP 583
7	Targeted Worst Zones	042602	PITTSFORD	BIRD LK - LCP 786
8	Targeted Worst Zones	049206	HASKELITE	BISSELL - LCP 288
9	Targeted Worst Zones	050803	BELDING	CKS CORNER - LCP 196
10	Targeted Worst Zones	051402	READING	CAMBRIA - LCP 603
11	Targeted Worst Zones	053601	ROSE CITY	ISLAND LAKE - LCP 108
12	Targeted Worst Zones	053601	ROSE CITY	ISLAND LAKE - LCP 96
13	Targeted Worst Zones	057601	POTTERVILLE	POTTERVILLE - LCP 103
14	Targeted Worst Zones	058202	ENGLISHVILLE	PINEISLAND - LCP 505
15	Targeted Worst Zones	060102	TUSTIN	LUTHER - LCP 431
16	Targeted Worst Zones	063202	HARLEM	HARLEM - LCP 475
17	Targeted Worst Zones	064202	TEKONSHA	WAGNER - LCP 93
18	Targeted Worst Zones	065702	EAST JORDAN	IRONTON - LCP 499
19	Targeted Worst Zones	065702	EAST JORDAN	IRONTON - LCP 579
20	Targeted Worst Zones	072802	LAINGSBURG	ROUND LAKE - LCP 217
21	Targeted Worst Zones	075704	MAPLE GROVE	SHAW BOX - LCP 341
22	Targeted Worst Zones	078902	ALTO	MCCORDS - LCP 578
23	Targeted Worst Zones	081501	HARPER ROAD	ARENS - LCP 363
24	Targeted Worst Zones	087704	BAGLEY	FREDERIC - LCP 202
25	Targeted Worst Zones	093404	CALVIN	WOODCLIFF - LCP 14
26	Targeted Worst Zones	093901	LYON MANOR	TREASURE - LCP 719
27	Targeted Worst Zones	095201	PECK ROAD	ORE-IDA - LCP 215
28	Targeted Worst Zones	095202	PECK ROAD	M-91 - LCP 525
29	Targeted Worst Zones	097202	EASTLAWN	FLAJOLE - LCP 348
30	Targeted Worst Zones	097202	EASTLAWN	FLAJOLE - LCP 300
31	Targeted Worst Zones	104101	GILSON	WYMAN - LCP 654
32	Targeted Worst Zones	107501	OBERLIN	MERIDITH - LCP 212
33	Targeted Worst Zones	112102	ABBE	CALDWELL - LCP 217
34	Targeted Worst Zones	112103	ABBE	HWY 33 - LCP 841
35	Targeted Worst Zones	121701	FROST	LONG LAKE - LCP 620
36	Targeted Worst Zones	127001	RANGER LAKE	KOKOSING - LCP 556
37	Targeted Worst Zones	127003	RANGER LAKE	LUPTON - LCP 28
38	Targeted Worst Zones	127003	RANGER LAKE	LUPTON - LCP 330
39	Targeted Worst Zones	127404	DUQUITE	PINE RIVER - LCP 556
40	Targeted Worst Zones	127404	DUQUITE	PINE RIVER - LCP 596
41	Targeted Worst Zones	127501	EAST TAWAS	ALABASTER - LCP 289
42	Targeted Worst Zones	127502	EAST TAWAS	LINCOLN STREET - LCP 48
43	Targeted Worst Zones	127702	LEVELY	STURGEON - LCP 860
44	Targeted Worst Zones	129802	VANDERBILT	WOLVERINE - LCP 346
45	Targeted Worst Zones	129802	VANDERBILT	WOLVERINE - LCP 559
46	Targeted Worst Zones	129902	ROSCOMMON	PIONEER - LCP 141
47	Targeted Worst Zones	141201	BACKUS	SPRNGBROOK - LCP 466
48	Targeted Worst Zones	141201	BACKUS	SPRNGBROOK - LCP 489
49	Targeted Worst Zones	147201	DORR CORNERS	RED RUN - LCP 398
50	Targeted Worst Zones	150001	WITHEY LAKE	PETTIT - LCP 804
51	Targeted Worst Zones	151502	BUSCH ROAD	CANADA - LCP 637
52	Targeted Worst Zones	151602	HUBBARD LAKE	MILLER RD - LCP 681
53	Targeted Worst Zones	160201	BARRYTON	BARRYTON - LCP 5
54	Targeted Worst Zones	026502	GUN LAKE	TRAIL END
55	Targeted Worst Zones	042301	GERRISH	LEGION - LCP 478
56	Targeted Worst Zones	047701	CONWAY	ODEN - LCP 366

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
LVD Capacity Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

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Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	LVD Lines Capacity	18,332	17,970	17,329	35,299	17,329
	Contractor	3,619	3,525	3,421	6,946	3,421
	Labor	1,763	1,717	1,666	3,383	1,666
	Materials	2,718	2,647	2,569	5,216	2,569
	Business Expenses	5	5	5	10	5
	Contingency	-	117	-	117	-
	Other (Loadings, Chargebacks)	10,227	9,960	9,667	19,627	9,667
2	LVD Transformers Capacity	4,610	3,476	4,128	7,604	4,128
	Contractor	1	1	1	1	1
	Labor	967	729	866	1,596	866
	Materials	1,954	1,473	1,750	3,223	1,750
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	1,688	1,272	1,511	2,784	1,511
3	**Total Capital**	22,942	21,446	21,457	42,903	21,457

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Low Voltage Distribution (LVD) Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-42 (AJB-9)

Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)		(d)
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected 2019 Test Year**		**Investment Category**
1	LVD Lines Capacity	Substation Equipment Overload	$	3,609	DISTRIBUTION WORK DRIVEN BY SUB PROJECT
		140% Overload or More and Low Cost/Cust between 130 and 140%	$	259	OVERLOADED BOOSTER/REGULATOR
		135% Overload or More or Low Cost/Cust First Zone Projects	$	1,172	OVERLOADED CONDUCTOR
		170% Overload or More	$	4,507	OVERLOADED FUSE
		140% Overload or More and Low Cost/Cust between 130 and 140%	$	705	OVERLOADED ISOLATOR
		170% Overload or More	$	78	OVERLOADED RECLOSER
		New Business Capacity	$	7,000	*Not listed*
		LVD Lines Capacity Total	$	17,330	

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Summary Projected Electric Capital Expenditures
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Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)
Line No.	**Overload Category**	**Feeder ID**	**Substation**	**Circuit**
1	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	024404	PORTAGE	LOVERSLANE
2	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	037002	OTTAWA BEACH	PORT SHELDON
3	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	048701	PEACH RIDGE	BALLARD
4	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	048702	PEACH RIDGE	KENOWA
5	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	078202	GREENBUSH	GREENBUSH
6	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	031201	LINCOLN	LOST LAKE
7	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	031202	LINCOLN	MIKADO
8	DISTRIBUTION WORK DRIVEN BY SUB PROJECT	157602	WEST CLARK LAKE	GRAND
9	OVERLOADED BOOSTER/REGULATOR	030602	REMUS	MILLBROOK
10	OVERLOADED CONDUCTOR	121001	NORTH KENT	ROCK HILL
11	OVERLOADED CONDUCTOR	077101	STANTON	DICKERSON LAKE
12	OVERLOADED CONDUCTOR	077601	KEATING	WOOD STREET
13	OVERLOADED CONDUCTOR	123701	WILMOTT	WILMOTT
14	OVERLOADED CONDUCTOR	076006	CHEYENNE	MCCARTY
15	OVERLOADED CONDUCTOR	051501	DUTTON	CRYSTAL SPRINGS
16	OVERLOADED CONDUCTOR	002701	MANISTEE	PARKDALE
17	OVERLOADED FUSE	055102	DAVISON	DELVE
18	OVERLOADED FUSE	100902	SURREY	MAIN STREET
19	OVERLOADED FUSE	033804	HARRISON	DODGE CITY
20	OVERLOADED FUSE	104202	ROGUE RIVER	ROGUE RIVER
21	OVERLOADED FUSE	002701	MANISTEE	PARKDALE
22	OVERLOADED FUSE	060602	BREEDSVILLE	GRAND JUNCTION
23	OVERLOADED FUSE	067601	MCGRAW	PORTSMOUTH
24	OVERLOADED FUSE	033803	HARRISON	STOCKWELL
25	OVERLOADED FUSE	130301	WEST ROAD	WOOD ROAD
26	OVERLOADED FUSE	039504	ROCKFORD	SUMMIT
27	OVERLOADED FUSE	063202	HARLEM	HARLEM
28	OVERLOADED FUSE	045701	HYDE PARK	DUCK LAKE
29	OVERLOADED FUSE	080302	BOYNE MOUNTAIN	MOUNTAIN LODGE
30	OVERLOADED FUSE	000201	MT PLEASANT	COLLEGE
31	OVERLOADED FUSE	122902	PLAINWELL	HEIGHTS
32	OVERLOADED FUSE	049102	CRYSTAL	CRYSTAL ROAD
33	OVERLOADED FUSE	127003	RANGER LAKE	LUPTON
34	OVERLOADED FUSE	049401	SHATTUCK	COUNTY FARM
35	OVERLOADED FUSE	154201	SPICEBUSH	LESTER LAKE
36	OVERLOADED FUSE	064101	BAYBERRY	KOSTER
37	OVERLOADED FUSE	081502	HARPER ROAD	EIFERT
38	OVERLOADED FUSE	082002	FORDYCE	LINCOLN
39	OVERLOADED FUSE	058201	ENGLISHVILLE	ENGLISHVILLE
40	OVERLOADED FUSE	021102	BLACK RIVER	FILLMORE
41	OVERLOADED FUSE	054102	MOLINE	GREEN LAKE
42	OVERLOADED FUSE	029102	HAMILTON	HAWKEYE
43	OVERLOADED FUSE	107601	ISABELLA	PICKARD
44	OVERLOADED FUSE	022202	COWAN LAKE	RAMSDELL
45	OVERLOADED FUSE	011201	CAMELOT LAKE	COLEMAN
46	OVERLOADED FUSE	095201	PECK ROAD	ORE-IDA
47	OVERLOADED FUSE	016204	REED CITY	HIGH SCHOOL
48	OVERLOADED FUSE	137804	SANDERSON	M-57
49	OVERLOADED FUSE	030401	WEIDMAN	BEAL CITY
50	OVERLOADED FUSE	043601	SHERIDAN	SIDNEY
51	OVERLOADED FUSE	061402	ROSEBUSH	DELWIN
52	OVERLOADED FUSE	060904	NAPOLEON	WOLF LAKE
53	OVERLOADED FUSE	073201	DONTZ ROAD	PORTAGE
54	OVERLOADED FUSE	042301	GERRISH	LEGION
55	OVERLOADED FUSE	132303	ORCHARD ROAD	SAGINAW ROAD
56	OVERLOADED FUSE	009901	FREELAND	RURAL
57	OVERLOADED FUSE	154101	BLUE STAR	PIER COVE
58	OVERLOADED FUSE	060904	NAPOLEON	WOLF LAKE
59	OVERLOADED FUSE	115902	BALLENGER	SALISBURY
60	OVERLOADED FUSE	000301	WEST RIVER	GRAND RIVER
61	OVERLOADED FUSE	074402	PINE RIVER	RURAL
62	OVERLOADED FUSE	064103	BAYBERRY	PLEASANT HILL
63	OVERLOADED FUSE	045101	WEST MAIN	CURWOOD
64	OVERLOADED FUSE	129002	PEACOCK	COLEMAN ROAD
65	OVERLOADED FUSE	050801	BELDING	CITY
66	OVERLOADED ISOLATOR	137201	BALZER	SANDERS
67	OVERLOADED ISOLATOR	084101	LOVEJOY	BRADEN
68	OVERLOADED ISOLATOR	084102	LOVEJOY	DEERFIELD
69	OVERLOADED ISOLATOR	081504	HARPER ROAD	AURELIUS
70	OVERLOADED ISOLATOR	137102	CLYDE ROAD	STATE ROAD
71	OVERLOADED ISOLATOR	022202	COWAN LAKE	RAMSDELL
72	OVERLOADED ISOLATOR	070201	MAGNUS	EAGLE CORNER
73	OVERLOADED ISOLATOR	148001	ARTHUR	ARTHUR
74	OVERLOADED ISOLATOR	135902	KIPP ROAD	HULL ROAD
75	OVERLOADED ISOLATOR	137101	CLYDE ROAD	GLENN ROAD
76	OVERLOADED ISOLATOR	022202	COWAN LAKE	RAMSDELL
77	OVERLOADED ISOLATOR	045301	BRICKER	ELLIS
78	OVERLOADED ISOLATOR	112103	ABBE	HWY 33
79	OVERLOADED ISOLATOR	124502	CEDAR LAKE	VAN ETTEN
80	OVERLOADED ISOLATOR	137801	SANDERSON	COUNTY FARM
81	OVERLOADED ISOLATOR	031202	LINCOLN	MIKADO
82	OVERLOADED ISOLATOR	024202	MCBAIN	VOGEL CENTER
83	OVERLOADED RECLOSER	151202	PARAMOUNT	BIRD
84	OVERLOADED RECLOSER	066601	ENSLEY	DISTRIBUTION

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
LVD Demand Failures Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

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Exhibit No.: A-43 (AJB-10)
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Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	LVD Lines Demand Failures	84,508	78,785	79,000	157,785	79,000
	Contractor	14,669	13,676	13,713	27,389	13,713
	Labor	12,402	11,562	11,594	23,156	11,594
	Materials	9,341	8,709	8,733	17,442	8,733
	Business Expenses	411	383	384	768	384
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	47,684	44,455	44,576	89,031	44,576
2	Distribution Metering	11,805	11,014	12,584	23,598	12,584
	Contractor	-	-	-	-	-
	Labor	2,466	2,301	2,629	4,930	2,629
	Materials	5,189	4,841	5,531	10,372	5,531
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	4,150	3,872	4,424	8,296	4,424
3	Distribution Transformers	20,747	15,641	18,576	34,217	18,576
	Contractor	4	3	4	7	4
	Labor	4,354	3,282	3,898	7,180	3,898
	Materials	8,794	6,630	7,874	14,504	7,874
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	7,595	5,726	6,800	12,525	6,800
4	Streetlight - Mercury Vapor	2,080	6,206	6,127	12,333	6,127
	Contractor	72	213	211	424	211
	Labor	233	696	687	1,382	687
	Materials	760	2,266	2,237	4,503	2,237
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	1,016	3,031	2,992	6,023	2,992
5	Metro Demand Failures	3,643	4,347	4,867	9,214	4,867
	Contractor	1,480	1,766	1,977	3,743	1,977
	Labor	251	300	336	635	336
	Materials	634	756	847	1,603	847
	Business Expenses	0	0	0	1	0
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	1,278	1,525	1,708	3,233	1,708
6	**Total Capital**	122,783	115,993	121,154	237,147	121,154

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Low Voltage Distribution (LVD) Projects
Summary Projected Electric Capital Expenditures
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($000)

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Exhibit No.: A-43 (AJB-10)
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Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)		(d)	(e)
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected 2019 Test Year**		**Work Description**	**Investment Category**
1	LVD Lines Demand Failures	Emergent Reffered to Design (Demand)	$	12,179	Complete 812 estimated locations	Not Listed
		Underground Rehabilitation	$	7,139	Complete 16 underground projects	Not Listed
		Overhead Copper Replacement	$	2,100	Complete 5 OH Copper projects	Not Listed
		Service Restoration Activities	$	38,000		Not Listed
		Streetlight Failures	$	3,000		Not Listed
		Underground Circuit Exit	$	840	Complete replacement of 12 circuit exits at 7 substations	UG Exit
		Targeted Worst Zones	$	7,769	Complete 45 Targeted Worst Zones	Targeted Worst Zones
		Line Work for Substation Project	$	600	Complete 2 substation driven rehabilitation projects	SUB - REHAB
		Voltage Improvement and System Protection	$	924	Complete 11 System Protection and Voltage Improvement Projects	Not Listed
		Complete 2014 and 2015 Security Assessments	$	6,449	Complete backlog of 2014 and 2015 Security Inspections	*Inspection*
			$	79,000		

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Low Voltage Distribution (LVD) Projects
Summary Projected Electric Capital Expenditures
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Case No.: U-20134
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Date: May 2018

Line No.	(a) Category	(b) Feeder ID	(c) Substation	(d) Circuit
1	Assessment	000202	MT PLEASANT	BROADWAY
2	Assessment	000704	MUSKEGON HEIGHTS	HEIGHTS
3	Assessment	001102	BELLA VISTA	BLAKELY
4	Assessment	003502	CADILLAC	HOSPITAL
5	Assessment	003503	CADILLAC	BOND
6	Assessment	003703	BOMAN	RIVERVIEW
7	Assessment	004101	TAWAS	EAST TAWAS
8	Assessment	008502	ELM STREET	VERONA
9	Assessment	012802	EVANSTON	EVANSTON
10	Assessment	014301	SPRING LAKE	SPRING LAKE
11	Assessment	014602	GREENSPIRE	CENTRE STREET
12	Assessment	014801	MORENCI	MOREY
13	Assessment	016202	REED CITY	MEDICAL
14	Assessment	016204	REED CITY	HIGH SCHOOL
15	Assessment	018901	FINE LAKE	BRISTOL
16	Assessment	020101	EDMORE	SIX LAKES
17	Assessment	022001	PITCHER	PROUTY
18	Assessment	022201	COWAN LAKE	GRATTAN
19	Assessment	022902	COOPER	COOPER CENTER
20	Assessment	023801	LAKE MITCHELL	GOLF CLUB
21	Assessment	024501	MONTROSE	VOLKMER
22	Assessment	024901	BITTERSWEET	DOWN HILL
23	Assessment	025702	OSHTEMO	HURD
24	Assessment	025901	HANOVER	PULASKI
25	Assessment	026901	OTSEGO	OTSEGO
26	Assessment	026902	OTSEGO	FARMER
27	Assessment	028201	HOMER	HOMER
28	Assessment	028303	CEDAR SPRINGS	WHITE CREEK
29	Assessment	029201	MANCHESTER	LOGAN ROAD
30	Assessment	029202	MANCHESTER	AUSTIN ROAD
31	Assessment	029203	MANCHESTER	MANCHESTER
32	Assessment	029502	STOCKBRIDGE	STOCKBRIDGE
33	Assessment	029601	VANDERCOOK LAKE	HAGUE RD
34	Assessment	029802	PALMYRA	VICTORSVILLE
35	Assessment	030001	ASHLEY	NORTH STAR
36	Assessment	032404	HOWARD CITY	CORAL
37	Assessment	032701	COMSTOCK	SHIELDS
38	Assessment	033302	AU GRES	AU GRES
39	Assessment	033602	LITCHFIELD	SIMPSON
40	Assessment	034801	HUDSONVILLE	HUDSONVILLE
41	Assessment	036004	LIBERTY	LIBERTY
42	Assessment	036802	APPLE	WOLF LAKE
43	Assessment	036901	COOLEY	WESTNEDGE
44	Assessment	036902	COOLEY	NORTH STREET
45	Assessment	036906	COOLEY	EXCHANGE
46	Assessment	037402	KNIGHT	FARLEY
47	Assessment	037602	BATTEESE	PLEASANT LAKE
48	Assessment	039803	SWARTZ CREEK	WINCHESTER
49	Assessment	040501	LASALLE	DIXIE
50	Assessment	040602	GODFREY	FLAT RIVER
51	Assessment	040701	ONSTED	ROME CENTER
52	Assessment	041701	GALESBURG	GALESBURG
53	Assessment	042102	LAKE LEANN	LAKE LEANN
54	Assessment	042304	GERRISH	MERRIO
55	Assessment	042402	MARION	MILL
56	Assessment	043601	SHERIDAN	SIDNEY
57	Assessment	043602	SHERIDAN	FENWICK
58	Assessment	043701	EDGEWOOD	DISTRIBUTION
59	Assessment	047501	BECKER	BEAR CREEK
60	Assessment	053102	PENNFIELD	PENNFIELD
61	Assessment	054801	LEONARD	IONIA
62	Assessment	058201	ENGLISHVILLE	ENGLISHVILLE
63	Assessment	058601	LEITH STREET	FRANKLIN
64	Assessment	060101	TUSTIN	WWTV
65	Assessment	060103	TUSTIN	LEROY
66	Assessment	060902	NAPOLEON	MOON LAKE
67	Assessment	061102	KENDALL	NICHOLS
68	Assessment	061401	ROSEBUSH	STEVENSTON LAKE
69	Assessment	061902	BROADWAY	BLACK CREEK
70	Assessment	063401	KILGORE	MILHAM
71	Assessment	063402	KILGORE	WISTERIA
72	Assessment	063404	KILGORE	TIMBERLANE
73	Assessment	064201	TEKONSHA	TEKONSHA
74	Assessment	065404	BISHOP	BELL RIVER
75	Assessment	066402	TRAVIS	COLLINGWOOD
76	Assessment	067401	DEXTER TRAIL	MILNER

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Low Voltage Distribution (LVD) Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-43 (AJB-10)

Witness: AJBordine
Date: May 2018

Line No.	(a) Category	(b) Feeder ID	(c) Substation	(d) Circuit
1	Assessment	068604	PARKWAY	SOUTH CENTRAL
2	Assessment	070304	INGHAM	THIRD STREET
3	Assessment	070305	INGHAM	GREENWOOD PARK
4	Assessment	071001	MESICK	SHERMAN
5	Assessment	071203	COLLEGE PARK	RIVERSIDE
6	Assessment	071702	SPRING ARBOR	ARBOR HILLS
7	Assessment	072401	THAYER	RIVER
8	Assessment	073101	MONA LAKE	AIRPORT
9	Assessment	073102	MONA LAKE	GRAND HAVEN
10	Assessment	074302	RED ARROW	BRISTOL
11	Assessment	074304	RED ARROW	OGEMA
12	Assessment	074402	PINE RIVER	RURAL
13	Assessment	076401	BEDFORD	MEACHEM
14	Assessment	076603	JUDD ROAD	AINSWORTH
15	Assessment	077201	SCIPIO	MOSHERVILLE
16	Assessment	078002	APPLETON	PERRY
17	Assessment	081501	HARPER ROAD	ARENS
18	Assessment	082201	MONTEREY	30TH STREET
19	Assessment	082202	MONTEREY	KNELLER
20	Assessment	085601	FORT CUSTER	HARMONIA
21	Assessment	085602	FORT CUSTER	GUARD
22	Assessment	085803	BLUE WATER	TOWNSEND ROAD
23	Assessment	086801	KOLASSA	KOSMERICK
24	Assessment	087701	BAGLEY	ALPINE
25	Assessment	088201	CARY ROAD	WOODSTOCK
26	Assessment	088202	CARY ROAD	LAKE COLUMBIA
27	Assessment	088203	CARY ROAD	MOSCOW
28	Assessment	090801	OAK STREET	COOPER STREET
29	Assessment	090804	OAK STREET	PLYMOUTH
30	Assessment	091601	AMPERSEE	WELDER
31	Assessment	091602	AMPERSEE	BORGESS
32	Assessment	091603	AMPERSEE	NORTH COMMERCIAL
33	Assessment	093201	BOON ROAD	MITCHELL STREET
34	Assessment	093202	BOON ROAD	ROUND LAKE
35	Assessment	093501	RANKIN	JENNINGS
36	Assessment	093502	RANKIN	GREEN VALLEY
37	Assessment	093901	LYON MANOR	TREASURE
38	Assessment	099201	MICOR	WELLWORTH
39	Assessment	100602	RED CEDAR	NORTHWIND
40	Assessment	100802	HARRIETTA	BOON
41	Assessment	102201	FILLMORE	N BLENDON
42	Assessment	102601	TEFT ROAD	LAKEFIELD
43	Assessment	102702	SAVIDGE	KELLY STREET
44	Assessment	103302	SQUIRE HILL	HILLSIDE
45	Assessment	104302	MORLEY	HOLLAND
46	Assessment	105302	ELLIS	LAKES MALL
47	Assessment	107203	ALAMO	OWEN
48	Assessment	109101	HENDERSHOT	MONROE ROAD
49	Assessment	111206	DRAKE ROAD	MAPLE HILL
50	Assessment	112002	HOGSBACK	SYCAMORE
51	Assessment	112101	ABBE	ABBE
52	Assessment	112201	KENT CITY	TYRONE
53	Assessment	113402	HARING	FAIR GROUNDS
54	Assessment	114302	MANTON	DOWNTOWN
55	Assessment	114602	ATWATER	VALLEY COLLEGE
56	Assessment	116801	WILDER	WILDER
57	Assessment	121001	NORTH KENT	ROCK HILL
58	Assessment	121002	NORTH KENT	MALL
59	Assessment	121004	NORTH KENT	FIVE MILE
60	Assessment	122402	PETTIS ROAD	PETTIS
61	Assessment	122704	STEEL DRIVE	VISTA
62	Assessment	122705	STEEL DRIVE	PONCHATRAIN
63	Assessment	123301	MCKEIGHAN	SHARON ROAD
64	Assessment	123701	WILMOTT	WILMOTT
65	Assessment	123702	WILMOTT	PARKER
66	Assessment	124701	FARRINGTON	CHASE
67	Assessment	124702	FARRINGTON	LAKOLA
68	Assessment	125202	UPTON	MARKET PLACE
69	Assessment	128403	MILLERS POINT	CONCORD
70	Assessment	129301	JOHNSON	LINCOLN
71	Assessment	133501	TALLMAN	WACOUSTA
72	Assessment	133503	TALLMAN	WRIGHT ROAD
73	Assessment	134801	PAVILION	PAVILION

($000)

Line No.	(a) Category	(b) Feeder ID	(c) Substation	(d) Circuit
1	Assessment	134802	PAVILION	MERIDETH
2	Assessment	136601	MAE	LINCOLN ROAD
3	Assessment	136602	MAE	ALBAIN ROAD
4	Assessment	137101	CLYDE ROAD	GLENN ROAD
5	Assessment	137102	CLYDE ROAD	STATE ROAD
6	Assessment	137801	SANDERSON	COUNTY FARM
7	Assessment	137802	SANDERSON	VAN DEINSE
8	Assessment	137805	SANDERSON	KENT ROAD
9	Assessment	138101	PORTSMOUTH	INDIANTOWN
10	Assessment	142703	IRISH ROAD	CRYSTALWOOD
11	Assessment	147602	VAN ATTA	VAN ATTA
12	Assessment	147901	DUFFIELD	COLE CREEK
13	Assessment	147902	DUFFIELD	DUFFIELD
14	Assessment	148001	ARTHUR	ARTHUR
15	Assessment	148002	ARTHUR	BERLIN
16	Assessment	149802	WEST FENTON	NORTH ROAD
17	Assessment	150702	EAST JACKSON	DONNELY
18	Assessment	150901	WINGATE	SOUTH
19	Assessment	150902	WINGATE	NORTH
20	Assessment	151901	HILL ROAD	REGENCY
21	Assessment	151903	HILL ROAD	PINE WAY
22	Assessment	153002	HUBBARDSTON ROAD	STONEY CREEK
23	Assessment	154101	BLUE STAR	PIER COVE
24	Assessment	154102	BLUE STAR	GANGES
25	Assessment	155302	HALLS LAKE	HALLS LAKE
26	Assessment	157002	MILBOURNE	PASADENA
27	Assessment	157801	TREMAINE	JORDAN LAKE
28	SUB - REHAB	002101	ROGERS HYDRO	STANWOOD
29	SUB - REHAB	TBD	HIGH BRIDGE	NEW SUBSTATION
30	Targeted Worst Zones	002001	GREENWOOD	RAU ROAD - LCP 451
31	Targeted Worst Zones	003506	CADILLAC	BERRY LAKE - LCP 998
32	Targeted Worst Zones	004801	PARMA	PARMA - LCP 118
33	Targeted Worst Zones	006802	HOMESTEAD	BEULAH - LCP 195
34	Targeted Worst Zones	006802	HOMESTEAD	BEULAH - LCP 364
35	Targeted Worst Zones	006802	HOMESTEAD	BEULAH - LCP 734
36	Targeted Worst Zones	008001	ALCONA DAM	GLENNIE - LCP 404
37	Targeted Worst Zones	017002	HARVEY STREET	DIAMOND - LCP 185
38	Targeted Worst Zones	022202	COWAN LAKE	RAMSDELL - LCP 829
39	Targeted Worst Zones	023001	BRONSON	BRONSON - LCP 667
40	Targeted Worst Zones	024301	AUSTIN	WEST LAKE - LCP 657
41	Targeted Worst Zones	024402	PORTAGE	SHAVER ROAD - LCP 506
42	Targeted Worst Zones	025102	NORTH MUSKEGON	DALTON - LCP 244
43	Targeted Worst Zones	030502	ORLEANS	ORLEANS - LCP 70
44	Targeted Worst Zones	031201	LINCOLN	LOST LAKE - LCP 628
45	Targeted Worst Zones	032202	MARNE	MARNE - LCP 576
46	Targeted Worst Zones	032301	SUNFIELD	MULLIKEN - LCP 752
47	Targeted Worst Zones	033803	HARRISON	STOCKWELL - LCP 5707
48	Targeted Worst Zones	039602	HOUGHTON HEIGHTS	PRUDENVLLE - LCP 380
49	Targeted Worst Zones	040802	OSCODA	BUTLER HTS - LCP 251
50	Targeted Worst Zones	042303	GERRISH	COTTAGE GR - LCP 603
51	Targeted Worst Zones	042602	PITTSFORD	BIRD LK - LCP 720
52	Targeted Worst Zones	049102	CRYSTAL	CRYSTAL ROAD - LCP 468
53	Targeted Worst Zones	049701	OLIVET	AINGER - LCP 521
54	Targeted Worst Zones	057102	CASCO	HAWKHEAD - LCP 442
55	Targeted Worst Zones	057402	PENINSULA	MAPLETON - LCP 279
56	Targeted Worst Zones	057802	VIRGINIA PARK	MACATAWA - LCP 652
57	Targeted Worst Zones	066504	CUTLERVILLE	GAINES - LCP 172
58	Targeted Worst Zones	074802	WEBB ROAD	PLAINFIELD - LCP 480
59	Targeted Worst Zones	078802	HONOR	PLATTE - LCP 107
60	Targeted Worst Zones	079702	GRAYLING	RIVER - LCP 96
61	Targeted Worst Zones	094602	NEWARK	EVANS ROAD - LCP 812
62	Targeted Worst Zones	115501	MAPLE CITY	CEDAR - LCP 745
63	Targeted Worst Zones	122401	PETTIS ROAD	HONEY CREEK - LCP 387
64	Targeted Worst Zones	129401	BROUGHWELL	MINARD - LCP 612
65	Targeted Worst Zones	129802	VANDERBILT	WOLVERINE - LCP 559
66	Targeted Worst Zones	137101	CLYDE ROAD	GLENN ROAD - LCP 14
67	Targeted Worst Zones	137801	SANDERSON	COUNTY FARM - LCP 414
68	Targeted Worst Zones	139501	WARNER	MILO - LCP 553
69	Targeted Worst Zones	139502	WARNER	BURCHETT - LCP 315
70	Targeted Worst Zones	140201	SIMMONS	DAM ROAD - LCP 569
71	Targeted Worst Zones	140401	ALGER	SKIDWAY - LCP 661
72	Targeted Worst Zones	142702	IRISH ROAD	WEXFORD - LCP 310
73	Targeted Worst Zones	148602	DEER LAKE	BALL AVE - LCP 792
74	Targeted Worst Zones	155801	SCHOOL RD	MOROCCO - LCP 248
75	UG Exit	106501	FOURTEENTH STREET	TOBIAS STREET
76	UG Exit	106502	FOURTEENTH STREET	LIPPINCOTT STREET
77	UG Exit	106503	FOURTEENTH STREET	LIBERTY STREET
78	UG Exit	111202	DRAKE ROAD	WURZBURG
79	UG Exit	121003	NORTH KENT	NORTHVILLE
80	UG Exit	129002	PEACOCK	COLEMAN ROAD
81	UG Exit	150903	PEACOCK	STOLL ROAD
82	UG Exit	014601	GREENSPIRE	MOORS
83	UG Exit	050101	EASTWOOD	TEXEL
84	UG Exit	050103	EASTWOOD	NAZARETH
85	UG Exit	059401	TEMPERANCE	WOOD ROAD
86	UG Exit	059402	TEMPERANCE	TEMPERANCE

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
LVD Asset Relocation Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-44 (AJB-11)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	LVD Asset Relocations	23,154	16,778	20,063	36,841	20,063
	Contractor	3,971	2,878	3,441	6,319	3,441
	Labor	3,986	2,888	3,454	6,342	3,454
	Materials	3,034	2,199	2,629	4,827	2,629
	Business Expenses	4	3	3	6	3
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	12,159	8,811	10,536	19,346	10,536
2	Metro Asset Relocations	4,791	9,919	3,140	13,059	3,140
	Contractor	2,341	4,716	1,534	6,250	1,534
	Labor	184	371	121	492	121
	Materials	620	1,250	407	1,656	407
	Business Expenses	2	5	2	7	2
	Contingency	-	269	-	269	-
	Other (Loadings, Chargebacks)	1,643	3,309	1,077	4,385	1,077
3	**Total Capital**	27,944	26,697	23,203	49,900	23,203

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
LVD Electric Operations Other Program
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-45 (AJB-12)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	Capital Tools	1,903	5,125	5,216	10,341	5,216
	Contractor	-	-	-	-	-
	Labor	0	1	1	2	1
	Materials	1,903	5,124	5,215	10,338	5,215
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	0	0	0	1	0
2	**Total Capital**	1,903	5,125	5,216	10,341	5,216

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-46 (AJB-13)

Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**Source**
1	Electric Division Expenses	$ 192,358	$ 183,430	$ 195,219	
2	Smart Energy Direct O&M Benefits	(15,201)	(16,916)	(17,496)	
3					
4	**Total Expense**	**$ 177,157**	**$ 166,514**	**$ 177,723**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Line No.	(a) Description	(b) Historical Labor 12 Mos Ended 12/31/2017	(c) Historical Non-Labor 12 Mos Ended 12/31/2017	(d) Historical Total 12 Mos Ended 12/31/2017	(e) Projected Labor 12 Mos Ending 12/31/2018	(f) Projected Non-Labor 12 Mos Ending 12/31/2018	(g) Projected Total 12 Mos Ending 12/31/2018	(h) Projected Labor 12 Mos Ending 12/31/2019	(i) Projected Non-Labor 12 Mos Ending 12/31/2019	(j) Projected Total 12 Mos Ending 12/31/2019	(k) Source
1	Electric Division Expenses	$ 108,881	$ 83,477	$ 192,358	$ 99,035	$ 84,395	$ 183,430	$ 102,184	$ 93,035	$ 195,219	
2	Smart Energy Direct O&M Benefits	(12,617)	(2,584)	(15,201)	(14,013)	(2,903)	(16,916)	(14,492)	(3,004)	(17,496)	
3											
4	**Total Expense**	**$ 96,264**	**$ 80,893**	**$ 177,157**	**$ 85,022**	**$ 81,492**	**$ 166,514**	**$ 87,692**	**$ 90,031**	**$ 177,723**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-47 (AJB-14)

Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**Source**
1	Electric Division Expenses - LVD	$ 155,630	$ 147,173	$ 156,964	
2	Smart Energy Direct O&M Benefits	(15,201)	(16,916)	(17,496)	
3					
4	**Total Expense**	**$ 140,429**	**$ 130,257**	**$ 139,468**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-47 (AJB-14)

Witness: AJBordine
Date: May 2018

Line No.	(a) Description	(b) Historical Labor 12 Mos Ended 12/31/2017	(c) Historical Non-Labor 12 Mos Ended 12/31/2017	(d) Historical Total 12 Mos Ended 12/31/2017	(e) Projected Labor 12 Mos Ending 12/31/2018	(f) Projected Non-Labor 12 Mos Ending 12/31/2018	(g) Projected Total 12 Mos Ending 12/31/2018	(h) Projected Labor 12 Mos Ending 12/31/2019	(i) Projected Non-Labor 12 Mos Ending 12/31/2019	(j) Projected Total 12 Mos Ending 12/31/2019	(k) Source
1	Electric Division Expenses	$ 89,901	$ 65,729	$ 155,630	$ 79,150	$ 68,023	$ 147,173	$ 81,313	$ 75,651	$ 156,964	
2	Smart Energy Direct O&M Benefits	(12,617)	(2,584)	(15,201)	(14,013)	(2,903)	(16,916)	(14,492)	(3,004)	(17,496)	
3											
4	**Total Expense**	**$ 77,284**	**$ 63,145**	**$ 140,429**	**$ 65,137**	**$ 65,120**	**$ 130,257**	**$ 66,821**	**$ 72,647**	**$ 139,468**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-48 (AJB-15)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**Source**
1	Electric Operations - LVD	$ 131,485	$ 121,450	$ 130,465	
2	Electric Engineering & Support - LVD	8,944	8,807	9,003	
3					
4	**Electric Division Expenses - LVD**	**$ 140,429**	**$ 130,257**	**$ 139,468**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-49 (AJB-16)

Witness: AJBordine
Date: May 2018

Electric Division Programs

Line No.	(a) Description	(b) 2017 Actual	(c) 2018 Projected	(d) 2019 Projected
1	O&M Assoc w/Construction	6,405	7,376	7,399
2	Transformer Credits	(8,925)	(7,059)	(7,082)
3	**O&M Associated with Construction**	**(2,520)**	**317**	**317**
4	Lines Reliability - LVD	157	50	50
5	Forestry - LVD	38,360	41,348	42,915
6	**Reliability**	**38,517**	**41,398**	**42,965**
7	Service Restoration	50,172	32,500	39,000
8	Corrective Maintenance	4,586	4,278	4,278
9	Staking	3,285	3,512	3,620
10	Meter Services (and Credits)	437	6,421	6,928
11	Streetlighting	1,637	1,533	1,533
12	Service Calls	2,839	2,487	2,487
13	Meter Reading	4,982	2,027	2,092
14	Meter Tech & Mgmt Sys Support	965	1,188	1,211
15	Smart Energy MTC - Elec	7,476	8,055	8,296
16	**Ops, Maint and Metering**	**76,379**	**62,001**	**69,445**
17	Training	6,075	5,750	5,373
18	Tools	1,461	1,500	1,616
19	Field Operations Expenses	2,604	2,000	2,000
20	Indirect Labor/Labor Variations	515	-	-
21	**Field Operations Services**	**10,655**	**9,250**	**8,989**
22	**Smart Energy Operations Center**	**1,166**	**1,256**	**1,357**
23	Resource Planning & Closeout	495	428	442
24	Scheduling & Dispatch	5,273	4,834	4,906
25	Contract Administration	353	378	392
26	**Planning & Scheduling**	**6,121**	**5,640**	**5,740**
27	**Operations Management**	**1,167**	**1,188**	**1,202**
28	**IT Projects**	**-**	**400**	**450**
29	**Electric Operations - LVD**	**131,485**	**121,450**	**130,465**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-49 (AJB-16)

Witness: AJBordine
Date: May 2018

Electric Division Programs

Line No.	(a) Description	(b) 2017 Actual	(c) 2018 Projected	(d) 2019 Projected
1	CES	354	366	366
2	Geospatial Mgmt & Data Quality	854	901	936
3	Infrastructure Attachments and Standards	267	339	339
4	Joint Pole Rental	1,805	1,803	1,803
5	Agreements - LVD & HVD	617	659	701
6	Grid Technologies - Dist	895	1,285	1,326
7	Electric Engineering - LVD	3,986	3,278	3,355
8	Standards & Materials	166	176	177
9	**Electric Engineering & Support - LVD**	**8,944**	**8,807**	**9,003**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Historic Actuals, Projected 2018, and Projected Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-50 (AJB-17)

Witness: AJBordine
Date: May 2018

Electric Division Programs

Line No.	(a) Description	(b) 2013 Actual	(c) 2014 Actual	(d) 2015 Actual	(e) 2016 Actual	(f) 2017 Actual	(g) 5-Year Average	(h) 2018 Projected	(i) 2019 Projected	(j) 2019 vs. 5-Year Average
1	O&M Assoc w/Construction	5,535	4,806	4,381	7,228	6,405	5,671	7,376	7,399	1,728
2	Transformer Credits	(5,589)	(6,788)	(6,146)	(6,134)	(8,925)	(6,716)	(7,059)	(7,082)	(366)
3	**O&M Associated with Construction**	**(54)**	**(1,982)**	**(1,765)**	**1,094**	**(2,520)**	**(1,045)**	**317**	**317**	**1,362**
4	Lines Reliability - LVD	1,879	1,054	235	56	157	676	50	50	(626)
5	Forestry - LVD	24,871	33,868	31,294	41,314	38,360	33,941	41,348	42,915	8,974
6	**Reliability**	**26,750**	**34,922**	**31,529**	**41,370**	**38,517**	**34,618**	**41,398**	**42,965**	**8,347**
7	Service Restoration	78,954	47,005	38,167	35,504	50,172	49,960	32,500	39,000	(10,960)
8	Corrective Maintenance	7,534	10,324	8,519	3,483	4,586	6,889	4,278	4,278	(2,611)
9	Staking	2,274	2,554	3,868	3,221	3,285	3,040	3,512	3,620	580
10	Meter Services (and Credits)	7,999	8,582	5,705	2,992	437	5,143	6,421	6,928	1,785
11	Streetlighting	1,515	1,709	1,805	1,584	1,637	1,650	1,533	1,533	(117)
12	Service Calls	2,351	2,650	2,799	2,457	2,839	2,619	2,487	2,487	(132)
13	Meter Reading	12,503	12,038	10,697	11,582	4,982	10,360	2,027	2,092	(8,268)
14	Meter Tech & Mgmt Sys Support	1,177	1,317	1,343	1,133	965	1,187	1,188	1,211	24
15	Smart Energy MTC - Elec					7,476	7,476	8,055	8,296	820
16	**Ops, Maint and Metering**	**114,307**	**86,179**	**72,903**	**61,956**	**76,379**	**88,326**	**62,001**	**69,445**	**(18,881)**
17	Training	7,520	5,279	6,047	4,174	6,075	5,819	5,750	5,373	(446)
18	Tools	1,660	1,330	1,920	1,811	1,461	1,636	1,500	1,616	(20)
19	Field Operations Expenses	2,206	1,565	2,346	2,360	2,604	2,216	2,000	2,000	(216)
20	Indirect Labor/Labor Variations	816	752	1,509	868	515	892	-	-	(892)
21	**Field Operations Services**	**12,202**	**8,926**	**11,822**	**9,213**	**10,655**	**10,564**	**9,250**	**8,989**	**(1,575)**
22	**Smart Energy Operations Center**					**1,166**	**1,166**	**1,256**	**1,357**	**191**
23	Resource Planning & Closeout	468	417	-	39	495	284	428	442	158
24	Scheduling & Dispatch	3,616	5,189	3,249	3,605	5,273	4,186	4,834	4,906	720
25	Contract Administration					353	353	378	392	39
26	**Planning & Scheduling**	**4,084**	**5,606**	**3,249**	**3,644**	**6,121**	**4,823**	**5,640**	**5,740**	**917**
27	**Operations Management**	**2,275**	**1,750**	**3,415**	**2,640**	**1,167**	**2,249**	**1,188**	**1,202**	**(1,047)**
28	**IT Projects**					**-**	**-**	**400**	**450**	**450**
29	**Electric Operations - LVD**	**159,564**	**135,401**	**121,153**	**119,917**	**131,485**	**140,700**	**121,450**	**130,465**	**(10,235)**
30	CES	646	587	499	360	354	489	366	366	(123)
31	Geospatial Mgmt & Data Quality			353	536	854	581	901	936	355
32	Infrastructure Attachments and Standards	1,009	1,384	905	455	267	804	339	339	(465)
33	Joint Pole Rental	1,706	1,733	1,791	1,789	1,805	1,765	1,803	1,803	38
34	Agreements - LVD & HVD	733	603	565	529	617	609	659	701	92
35	Grid Technologies - Dist	1,073	1,040	1,008	976	895	998	1,285	1,326	328
36	Electric Engineering - LVD	3,502	3,764	2,956	2,085	3,986	3,259	3,278	3,355	96
37	Standards & Materials	213	230	190	156	166	191	176	177	(14)
38	**Electric Engineering & Support - LVD**	**8,882**	**9,341**	**8,267**	**6,886**	**8,944**	**8,696**	**8,807**	**9,003**	**307**
	Total O&M - LVD	**168,446**	**144,742**	**129,420**	**126,803**	**140,429**	**149,396**	**130,257**	**139,468**	**(9,928)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric & Common O&M Expenses
For the Test Year 12 Months Ending December 31, 2019 Compared to the EDIIP
($000)

Case No.: U-20134
Exhibit No.: A-51 (AJB-18)
Page: 1 of 1
Witness: AJBordine
Date: May 2018

Electric Division Programs

Line No.	(a) Rate Case Program	(b) EDIIP Filing Program	(c) EDIIP Filing Included	(d) 2019 Projected	(e) Less Smart Energy Benefits	(f) 2019 Net Projected	(g) Witness
1	O&M Assoc w/Construction	Net O&M Assoc with Construction	7,399	7,399		7,399	AJ Bordine
2	Transformer Credits	Net O&M Assoc with Construction	(7,082)	(7,082)		(7,082)	AJ Bordine
3	**O&M Associated with Construction**		**317**	**317**	**-**	**317**	
4	Lines Reliability - LVD	Reliability	50	50		50	AJ Bordine
5	Lines Reliability - HVD	Reliability	125	125		125	JRAnderson
6	Substations Reliability - LVD	Reliability	1,618	1,618		1,618	JRAnderson
7	Substations Reliability - HVD	Reliability	1,282	1,282		1,282	JRAnderson
8	Forestry - LVD	Forestry	42,915	42,915		42,915	AJ Bordine
9	Forestry - HVD	Forestry	10,200	10,200		10,200	JRAnderson
10	**Reliability**		**56,190**	**56,190**	**-**	**56,190**	
11	Service Restoration	Service Restoration	39,000	39,651	(651)	39,000	AJ Bordine
12	Lines Demand - HVD	Demand Maintenance	798	798		798	JRAnderson
13	Substations Demand - LVD	Demand Maintenance	3,162	3,162		3,162	JRAnderson
14	Substations Demand - HVD	Demand Maintenance	2,151	2,151		2,151	JRAnderson
15	Corrective Maintenance	Corrective Maintenance	4,278	4,278		4,278	AJ Bordine
16	Staking	Staking / Streetlight / Service Calls	3,620	3,620		3,620	AJ Bordine
17	Meter Services (and Credits)	Meter services and credits	6,928	9,879	(2,951)	6,928	AJ Bordine
18	Streetlighting	Staking / Streetlight / Service Calls	1,533	1,533		1,533	AJ Bordine
19	Service Calls	Staking / Streetlight / Service Calls	2,487	2,487		2,487	AJ Bordine
20	Alma Equipment Repair	Other Ops metering	1,174	1,174		1,174	JRAnderson
21	Meter Reading	Meter Reading	2,092	15,986	(13,894)	2,092	AJ Bordine
22	Meter Tech & Mgmt Sys Support	Other Ops metering	1,211	1,211		1,211	AJ Bordine
23	Smart Energy MTC - Elec	Smart Energy MTC - Elec	8,296	8,296		8,296	AJ Bordine
24	**Ops, Maint and Metering**		**76,730**	**94,226**	**(17,496)**	**76,730**	
25	Training	Training	5,373	5,373		5,373	AJ Bordine
26	Facilities Building Ops & Maint	Facilities Building Opers & Maint	3,513	-		-	Latina Johnson
27	Tools	Other Field Operations	1,616	1,616		1,616	AJ Bordine
28	Field Operations Expenses	Other Field Operations	2,000	2,000		2,000	AJ Bordine
29	Supervision/Admin - Staff	Supervision / Admin-Staff	7,343	7,343		7,343	JRAnderson
30	**Field Operations Services**		**19,845**	**16,332**	**-**	**16,332**	
31	**Smart Energy Operations Center**	Smart Energy Operations Center	**1,357**	**1,357**		**1,357**	AJ Bordine
32	**Grid Management**	Grid Management	**4,998**	**4,998**		**4,998**	JRAnderson
33	Resource Planning & Closeout	Planning & Scheduling	442	442		442	AJ Bordine
34	Scheduling & Dispatch	Planning & Scheduling	4,906	4,906		4,906	AJ Bordine
35	Contract Administration	Planning & Scheduling	392	392		392	AJ Bordine
36	**Planning & Scheduling**		**5,740**	**5,740**	**-**	**5,740**	
37	**Operations Performance**	Operations Performance	**1,676**	**-**		**-**	John Broschak
38	**Operations Management**	Operations Management	**1,202**	**1,202**		**1,202**	AJ Bordine
39	**Accruals - Injuries & Damagage**	Operations Management	**4,707**	**-**		**-**	Dan Harry
40	**Accruals - EICP**	Operations Management	**1,133**	**-**		**-**	Amy Conrad
41	**IT Projects**	Engineering & Ops Support	**450**	**450**		**450**	AJ Bordine
42	**Electric Operations**		**174,345**	**180,812**	**(17,496)**	**163,316**	

Line No.			EDIIP Filing Included	2019 Projected	Less Smart Energy Benefits	2019 Net Projected	Witness
43	Rate Case Administration	Engineering & Ops Support	87	87		87	JRAnderson
44	Regulatory & Compliance	Engineering & Ops Support	199	199		199	JRAnderson
45	CES	Engineering & Ops Support	366	366		366	AJ Bordine
46	Geospatial Mgmt & Data Quality	Engineering & Ops Support	936	936		936	AJ Bordine
47	Infrastructure Attachments and Standards	Engineering & System planning	339	339		339	AJ Bordine
48	Joint Pole Rental	Joint Pole Rental	1,803	1,803		1,803	AJ Bordine
49	Agreements - LVD & HVD	Engineering & Ops Support	701	701		701	AJ Bordine
50	Grid Technologies - Dist	Engineering & System planning	1,326	1,326		1,326	AJ Bordine
51	Electric Engineering - LVD	Engineering & System planning	3,355	3,355		3,355	AJ Bordine
52	Standards & Materials	Engineering & System planning	177	177		177	AJ Bordine
53	Electric Engineering - HVD	Engineering & System planning	5,118	5,118		5,118	JRAnderson
54	Financial Mgmt & Controls - EPM team	Engineering & Ops Support	101	-		-	John Broschak
55	Financial Mgmt & Controls - Budget & Reporting team	Engineering & Ops Support	424	-		-	Dan Harry
56	Project Management - Electric portion of Chris Fultz	Engineering & Ops Support	845	-		-	John Broschak
57	**Electric Engineering**		**15,777**	**14,407**	**-**	**14,407**	
58	**Total Electric Distribution**		**190,122**	**195,219**	**(17,496)**	**177,723**	

Classification of Customer and Demand Related Costs

FERC Accounts 364-368

April 2018

Introduction

The company is evaluating the classification of distribution assets between demand-related and customer-related costs in support of a cost of service study. Rates & Regulatory Cost Analysis (R&RC) has made a determination regarding most Federal Energy Regulatory Commission (FERC) designated accounts, but has requested Electric Regulatory & Strategy Implementation (ER&SI) evaluate FERC accounts 364-368.

Background

The proposed classification of costs represents a shift from demand-related to customer-related costs compared to the methodology currently used by the Company. Therefore, the analysis contained herein is intended to be conservative in determination of the portion classified as Customer (i.e. bias to Demand). This review does provide some guidance as to potential bias in the individual sections for future consideration.

The approach taken in this evaluation is based on the "Minimum Size Method" as recommended by the National Association of Regulatory Utility Commissioners (NARUC) in its Electric Utility Cost Allocation Manual published in 1992. Additional guidance is taken from Electricity Pricing: Engineering Principles and Methodologies (EP&M) by Lawrence J. Vogt, 2009. The Minimum Size Method attempts to determine the necessary minimum infrastructure to serve a utility's customers. In other words, what would it take to serve all of the customers if each customer is using a minimal amount of electricity? This minimum system is considered the fixed (Customer) costs. The costs associated with infrastructure over and above this minimum system are considered to be a variable (Demand) cost.

Classification of Infrastructure FERC Accounts 364-368

NARUC's approach uses the minimum unit cost presently being installed. Once this minimum unit cost is identified then R&RC should apply this unit cost to all units.

<u>HVD Lines & Substations</u>

The NARUC classifies all substation equipment as Demand. A strong argument could be made that there is a minimum substation infrastructure and these minimum costs should be classified as Customer. This is especially true for Low Voltage Distribution (LVD) substations that are part of a radial distribution system. However, R&RC has determined that all substations will be classified as Demand at this time. Given the LVD substations are being classified as Demand, for consistency, the upstream portion of the system should also be Demand and therefore, the High Voltage Distribution (HVD) system will be classified as Demand. The subsequent division of cost applies only to the LVD system.

<u>FERC Account 364 (Structures)</u>

The minimum unit for charges to this account is a LVD wood pole 45 feet and under (RU ID #3817). Cross-arms and insulators are necessary structure fixtures and should be included as well.

Taller poles are typically a result of design factors that are not related to load. Taller poles increase span length reducing the number of poles needed. Taller poles are sometimes used to increase clearance from vegetation or to cross obstacles such as a river. These are all non-load related functions. A future analysis should consider if a determination of pole function can be refined.

FERC Account 365 (Overhead Conductor & Devices)
The minimum unit for charges to this account is ACSR Conductor # 2/0 and below (RU ID #1019). This is by far the most commonly installed unit. There is a significant amount of copper conductor which would have been a commonly installed minimum unit at one time, but is considered obsolete. The incremental cost for aerial spacer cable could be considered as Customer cost. The spacer cable is installed for reliability in high tree density areas and not for incremental capacity. In keeping with a conservative approach, it is recommended that R&RC apply the minimum conductor unit for all LVD primary conductors. For secondary, the commonly used triplex conductor unit is RU ID #1026.

NARUC is silent on devices, which could imply they recommend these to be Demand costs which would be incorrect. Devices such as cutouts and recloser are installed to de-energize lines in the event of a fault. These devices are for public safety, reliability, operability and to minimize equipment damage. The function of these devices does not change with load. It is recommended that these devices be consider a Customer cost. This is consistent with EP&M.

FERC Account 366 (Underground Conduit)
At this time, the minimum unit recommendation for charges to this account is 1 Duct (RU ID # 5707), which is not the most commonly installed. In keeping with an approach that is conservative when allocating costs to Customer, the less frequently used single duct is recommended as the minimum unit. Other materials such as vaults, switches, and manholes should be considered a Customer costs. This equipment is necessary for operability.

FERC Account 367 (Underground Cable)
Similar to conduit, the single aluminum conductor (RU ID #5540) is selected as the minimum even though double aluminum conductor is installed over 5.5 times more frequently. Installation of the second conductor is only 18% additional costs and may be installed for reliability purposes. In practice, installation of a second conductor may be the practical minimum however in keeping with the conservative allocation to Customer, the single conductor was selected.

FERC Account 368 (Line Transformers)
For both pole top and pad mounted transformers, 37.5 kVA or smaller are the most frequent and smallest units for charges to this account. These units are RU ID #503 and #487 designated as the minimum infrastructure.

Summary

The future role of electric utilities is evolving to more of an enabler of technologies such as customer renewable energy, battery storage, demand side management, etc. and less of a generator and distributor of energy. As such, a determination of the minimum system needed to support the changing role of the electric utility is appropriate. The approach taken in this initial review is conservative in defining the minimum necessary infrastructure to serve the customer's minimum load in support of upcoming regulatory proceedings. Future filings are likely to consider a more in-depth evaluation of the required minimum system.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

RACHEL L. BREGE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

1. Tariff Sheet Nos. A-5.00, D-6.00, D-6.05, D-6.10, D-8.10 through D-8.40 and D-16.10 through D-17.40 – **Residential Rate Restructuring** – Updated the availability clauses and added termination dates to the existing residential rates and added proposed Residential Summer On-Peak Basic Rate RSP, Residential Smart Hours Rate RSH and Residential Nighttime Savers Rate RPM within the Index, references in the Electric Rate Book, and the corresponding Rate Schedules.

2. Tariff Sheet No. C-3.10 – Rule C1 – **Characteristics of Service** – Updated Contribution in Aid of Construction Allowance Schedule.

3. Tariff Sheet Nos. C-24.00, C-25.00, D-6.10, D-7.00, D-21.20 and D-36.30 – Rule C4.4 – **Resale** –Added General Service Secondary Time-of-Use Rate GSTU and General Service Primary Time-of-Use Rate GPTU as a qualifying resale rate, updated all-inclusive rates for campgrounds and boat harbor slips and increased the penalty for not meeting the obligations of resale to 15% .

4. Tariff Sheet No. C-32.10 – Rule C5.4 – **Shutoff Protection Plan for Residential Customers** – Added language to clarify that the Rules C1.3 and C5.1 allow the Company to deny or shut off service.

5. Tariff Sheet No. C-32.20 – Rule C5.5 – **Non-Transmitting Meter Provision –** Updated prices

6. Tariff Sheet Nos. C-42.00, C-48.66, D-43.00, E-23.00, E-25.00 and E-27.00 – **Line Loss Factors** – Updated the line loss factors.

7. Tariff Sheet Nos. D-2.00 and D-2.20 – **Surcharges** – Added IRM Surcharges and the Railway Expense Recovery Surcharge.

8. Tariff Sheet Nos. D-6.00, D-6.05, D-6.10 and D-7.00 – **Rate Categories and Provisions –** Updated pages to reflect proposed new and deleted Rate Categories and Provisions.

9. Tariff Sheet Nos. D-9.00, D-10.00, D-11.00, D-11.10, D-13.01, D-13.02, D-13.10, D-13.20, D-13.25, D-14.00, D-15.00, D-18.00, D-19.00, D-21.10, D-21.20, D-22.00, D-24.00, D-27.00, D-27.10, D-28.00, D-31.00, D-31.05, D-31.10, D-32.00, D-33.00, D-36.20, D-36.30, D-37.10, D-37.20, D-37.30, D-43.00, D-44.00, D-45.00, D-46.00, D-47.00, D-51.00, D-54.02 and D-54.10 – **Rate Schedules** – Revised prices.

10. Tariff Sheet Nos. D-11.00, D-13.03, D-13.20, D-15.00, D-19.10, D-21.30, D-24.00, D-29.00, D-34.00, D-36.40, D-37.40 – **Administrative Cost Charge –** increased the generation capacity to 550 kW.

11. Tariff Sheet Nos. D-34.00 and D-34.10 – **Interruptible Service Provision (GI) –** Increased the maximum limit of load contracted as interruptible to 100,000 kW and added language to align with the GI provision contract.

12. Tariff Sheet Nos. D-34.20, D-34.30, D-34.40 and D-35.00 – **Large General Service Primary Demand Rate GPD –** Added the Interruptible Service Provision – Market Price Option (GI2).

13. Tariff Sheet Nos. E-6.00, E-7.00, E-20.00, E-22.00, E-24.00, E-25.00 and E-27.00 – **Retail Open Access Metering** – Updated the metering options to include Wireless Under Glass Meters.

INDEX

(Continued From Sheet No. A-4.00)

SECTION D
RATE SCHEDULES (Contd)

(Continued on Sheet No. A-6.00)

See Brege Testimony, Page 4, Lines 9-22; Exhibit A-53 (RLB-1) Item #1

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.4 Extraordinary Facility Requirements and Charges (Contd)

Contribution In Aid of Construction Allowance Schedule

Schedule	Customer Voltage Level(CVL)	With a Full Service Contract, by Contract Duration: 1 Year	2 Year	3 Year	4 Year	5 Year	Without Full Service Contract
General Service Primary Rate GP	1	$~~0.024~~ *0.025*/kWh	$~~0.046~~ *0.047*/kWh	$~~0.066~~ *0.069*/kWh	$~~0.085~~ *0.088*/kWh	$~~0.102~~ *0.107*/kWh	$~~0.023~~ *0.018*/kWh
	2	~~0.031~~ *0.027*/kWh	~~0.051~~ *0.052*/kWh	~~0.074~~ *0.075*/kWh	~~0.095~~ *0.096*/kWh	~~0.115~~ *0.116*/kWh	~~0.031~~ *0.024*/kWh
	3	~~0.049~~ *0.041*/kWh	~~0.065~~ *0.066*/kWh	~~0.094~~ *0.096*/kWh	~~0.121~~ *0.123*/kWh	~~0.146~~ *0.149*/kWh	~~0.049~~ *0.041*/kWh
Large General Service Primary Demand Rate GPD	1	$~~85~~ *135*/kW	$~~165~~ *260*/kW	$~~240~~ *375*/kW	$~~310~~ *480*/kW	$~~375~~ *580*/kW	$40/kW
	2	~~95~~ *155*/kW	~~185~~ *295*/kW	~~270~~ *430*/kW	~~345~~ *550*/kW	~~415~~ *665*/kW	~~70~~ *75*/kW
	3	~~150~~ *195*/kW	~~245~~ *370*/kW	~~355~~ *540*/kW	~~460~~ *695*/kW	~~555~~ *840*/kW	~~150~~ *140*/kW
General Service Primary Time-of-Use Rate GPTU	1	~~0.015~~ *0.024*/kW h	~~0.029~~h *0.045*/kW	~~0.042~~ *0.066*/kWh	~~0.055~~ *0.085*/kWh	~~0.066~~ *0.102*/kW	NA
	2	~~0.017~~ *0.027*/kWh	~~0.032~~ *0.052*/kWh	~~0.047~~ *0.075*/kWh	~~0.061~~ *0.097*/kWh	~~0.073~~ *0.117*/kWh	NA
	3	~~0.022~~ *0.034*/kWh	~~0.043~~ *0.065*/kWh	~~0.062~~ *0.095*/kWh	~~0.080~~ *0.122*/kWh	~~0.097~~ *0.147*/kWh	NA
Energy Intensive Primary Rate EIP	1	~~0.002~~ *0.014*/kWh	~~0.003~~ *0.027*/kWh	~~0.005~~ *0.039*/kWh	~~0.006~~ *0.051*/kWh	~~0.008~~ *0.061*/kWh	NA
	2	~~0.004~~ *0.021*/kWh	~~0.009~~ *0.040*/kWh	~~0.012~~ *0.058*/kWh	~~0.016~~ *0.075*/kWh	~~0.019~~ *0.091*/kWh	NA
	3	~~0.007~~ *0.022*/kWh	~~0.014~~ *0.042*/kWh	~~0.020~~ *0.061*/kWh	~~0.026~~ *0.078*/kWh	~~0.032~~ *0.095*/kWh	NA

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, minimum bills, require upfront deposit and other service conditions, including, but not limited to, when the customer's load requirements are of a short-term duration, temporary or a transient nature, or if in the opinion of the Company, the customer does not have acceptable credit history or represents an unacceptable credit risk or other reasons within the sound discretion of the Company.

C1.5 Invalidity of Oral Agreements or Representations

When a written contract is required, no employee or agent of the Company is authorized to modify or supplement the Rules and Regulations and Rate Schedules of the Electric Rate Book by oral agreement or representation, and no such oral agreement or representation shall be binding upon the Company.

(Continued on Sheet No. C-4.00)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #2

(Continued From Sheet No. C-23.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(5) The customer must notify individuals and/or co-owners utilizing the customer's property that the customer's facilities may not be able to be located by Miss Dig.
(6) The customer must notify individuals and co-owners utilizing the customer's property that requests and concerns regarding electric service will be addressed between the single legal entity and ownership and primary operating authority, not with individuals.
(7) The customer shall be responsible for ensuring that the electrical facilities are adequate to meet the needs of the units placed within the Seasonal Condominium Campground in their entirety and shall pay the Company for any charges incurred for modifications necessary to accommodate load according to other portions of this Electric Rate Book.

C4.4 Resale

This provision is closed to resale for general unmetered service, unmetered or metered lighting service and new or expanded service for resale for residential use.
No customer shall resell electric service to others except when the customer is served under a Company rate expressly made available for resale purposes, and then only as permitted under such rate and under this rule.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation upon extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, the Company may allow a customer to resell electric service to others.

For the purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service.

A resale customer is required to take service under the resale provision of one of the following rates for which they qualify: General Service Secondary Rate GS, *General Service Secondary Time-of-Use Rate GSTU,* General Service Secondary Demand Rate GSD, General Service Primary Rate GP, ~~or~~ Large General Service Primary Demand Rate GPD*, or General Service Primary Time-of-Use Rate GPTU*. Resale Service is provided pursuant to a service contract providing for such resale privilege. Service to each ultimate user shall be separately metered.

A. If the resale customer elects to take service under a Company Full Service resale rate, the ultimate user shall be served and charged for such service under standard Rate RS for residential use or under the appropriate standard General Service Rate applicable in the Company's Electric Rate Book available for similar service under like conditions. Reselling customers are not required to offer or administer any additional service provisions or nonstandard rates contained in the Electric Rate Book, such as the Income Assistance Service Provision, Residential Service Time-of-Day Secondary Rate RT or the Educational Institution Service Provision.

B. If the resale customer elects to take service under a Company Retail Open Access Service rate, the ultimate user shall be served and charged for such service under Rate ROA-R for residential use or under Rate ROA-S or ROA-P applicable in the Company's Electric Rate Book available for similar service under like conditions.

C. If the ultimate user is a campground lot or boat harbor slip, the resale customer has the option to charge a maximum of the following all-inclusive rate per kWh in place of billing the ultimate customer on the appropriate standard Company tariff rate:

$~~0.151312~~ *0.153725* per kWh for all kWh during the months of June-September
$~~0.147394~~ *0.152723* per kWh for all kWh during the months of October-May

The Company shall be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.
The service contract shall provide that the reselling customer's billings to the ultimate user shall be audited each year by February's month end, for the previous calendar year. The audit shall be conducted either by the Company, if the Company elects to conduct such audit, or by an independent auditing firm approved by the Company. The reselling customer shall be assessed a reasonable fee for an audit conducted by the Company. If the audit is conducted by an independent auditing firm, the customer shall submit a copy of the results of such audit to the Company in a form approved by the Company.

(Continued on Sheet No. C-25.00)

(Continued From Sheet No. C-24.00)

C4. APPLICATION OF RATES (Contd)

C4.4 Resale (Contd)

The service contract shall also provide that the reselling customer shall be responsible for the testing of each ultimate user's meter at least once every 3 years. The accuracy of such meters shall be maintained within the limits as prescribed in Rule B1., Technical Standards for Electric Service. Meters shall be tested only by outside testing services or laboratories approved by the Company.

A record of each meter, including testing results, shall be kept by the reselling customer during use of the meter and for an additional period of one year thereafter. When requested, the reselling customer shall submit certified copies of the meter test results and meter records to the Company.

The reselling customer shall supply each ultimate user with an electric system adequate to meet the needs of the ultimate user with respect to the nature of service, voltage level and other conditions of service. The reselling customer shall render a bill once during each billing month to each of the customer's tenants in accordance with approved Rate Schedules of the Company. Every bill rendered by the reselling customer shall specify the following information: the rate categories and provisions; the due date; the beginning and ending meter readings of the billing period and dates thereof; the difference between the meter readings; the Power Supply Cost Recovery Factor; if applicable; the subtotal of the bill before taxes; amount of sales tax; other local taxes where applicable; any previous balance; the amount due for delivery service and/or power supply service, as applicable; the amount due for other authorized charges; and the total amount due. The due date of the customer's bill shall be 21 days from the date of rendition.

If the reselling customer fails to meet the obligations of this rule, the Company shall notify the Commission. If, after review with the reselling customer, the problem is not resolved, the Company shall assess a penalty in the amount of ~~5~~*15*% of the resale customer's bill before taxes per month until the problem is resolved. The reselling customer is not permitted to pass the resale penalty cost on to its ultimate customer(s). If the problem is not resolved after three months, the Company shall shut off electric service until the problem is resolved. The Company shall not incur any liability as the result of this shutoff of electric service.

The renting of premises with the cost of electric service included in the rental as an incident of tenancy is not considered to be a resale of such service.

Neither the resale of electric services provided by Consumers Energy nor the sale of self-generation at publicly available electric vehicle charging stations is subject to Commission regulation and no restrictions are imposed on the rate charged or rate structure to the ultimate motor vehicle customers, as those sales are being made into the competitive motor fuels market.

C4.5 Mobile Home Park - Individually Served

For purposes of this rule, the definition of a mobile home park is a parcel or tract of land upon which three or more mobile homes are located on a continuous nonrecreational basis.

Service to separately metered mobile homes shall be billed on the appropriate Residential Service Rate under the following conditions:

Service to all new mobile home parks and expanded service to existing mobile home parks receiving electrical service shall be provided through individual tenant metering.

The mobile home park shall be of a permanent nature with improved streets and with individual water and sewer connections to each lot. Ordinarily, electric service to a mobile home shall be in the name of the occupant. However, service to lots designated for occasional or short-term occupancy shall be in the name of the owner of the park or his/her authorized representative.

(Continued on Sheet No. C-26.00)

See Brege Testimony, Page 3, Lines 1-13; Exhibit A-53 (RLB-1) Item #3

(Continued From Sheet No. C-32.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

B. Enrollment

An eligible customer may enroll at any time of the calendar year in the SPP. Where unauthorized use of utility service has not occurred, to enroll an eligible customer must (1) contact the Company and indicate that they wish to enroll, (2) be able to demonstrate that he or she has made application for state or federal heating assistance, or has a household income that does not exceed 200% of the federal poverty guidelines as published by the United States Department of Health and Human Services or receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid, (3) within 14 days of a customer calling to enroll in the SPP, have completed the enrollment process by paying a minimum down payment of 10% of the total amount owed to the Company at the time of the request to enroll. An eligible customer is not enrolled in the SPP until the enrollment requirements are fulfilled. Customers previously enrolled in the SPP the last twelve months who default may be permitted to re-enroll in a modified SPP payment arrangement, at the discretion of the Company, if they have demonstrated a willingness to satisfy the terms of the payment plan through their payment history or have received assistance that will improve the customer's ability to satisfy the payment arrangements. The modified SPP repayment period shall not exceed 24 months.

Customers who enroll in the SPP who have not been enrolled in the SPP for more than twelve months may not be required to pay a deposit or reconnection fee, if applicable. Customers who enroll in the SPP who were previously enrolled in the SPP in the last twelve months and removed due to default may be required to pay a deposit and a reconnection fee, if applicable.

Where unauthorized use of utility service has occurred, the customer must pay 100% of the portion of charges that are the result of the unauthorized use. Upon receipt of payment, the customer shall be considered eligible if all other eligibility requirements are met. The customer may then enroll under the conditions described previously. The payment of unauthorized use charges may be made at the same time as the down payment of the total amount owed to the Company is made. In the event that the down payment of the total amount owed to the Company is made without payment of the unauthorized charges at the same time or previously, the payment received shall first be applied to the unauthorized charges.

In the event that an eligible customer has contacted the Company to indicate a wish to enroll but the requirements so described are not met in full, the eligible customer shall then be subject to credit action as though no contact with the Company had occurred. In the event that all Company obligations to shut off service have been met, the eligible customer shall receive a minimum of one communication at least 24 hours prior to shutoff of service.

C. Customer Protection

Once enrolled in the SPP, a utility shall not shut off service to a SPP Customer if the customer pays to the Company a monthly amount equal to 1/12th of the estimated annual bill for the SPP Customer and a Company-specified amount between 1/12th and 1/24th of any remaining delinquent balance owed to the Company at the time of the enrollment. *The Company shall have the right to deny or shut off service in accordance with Rules and Regulations of the Company as authorized by the Michigan Public Service Commission outlined in Rule C1.3, Use of Service and in Rule C5.1, Access to Customer's Premises.* While the customer is enrolled in the SPP and payments are made by the due date of the amount due shown on the bill, no late payment charges will be assessed. The SPP Customer may participate in the SPP for a maximum period of 24 months or until the delinquent charges are eliminated and the SPP Customer is able to pay his or her regular monthly energy bills.

(Continued on Sheet No. C-32.20)

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #4

(Continued From Sheet No. C-32.10)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

C. Customer Protection (Contd)

The estimated annual bill for the SPP Customer and the delinquent balance due may be recalculated periodically by the Company. The Company may also recalculate the estimated annual bill and the delinquent balance due upon the transfer of a balance owed on another account in compliance with Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service.

D. Default

Should a SPP Customer fail to make payment by the due date, a shutoff notice specific to this SPP shall be issued but shall comply with the requirements of Part 8 of Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service. If the SPP Customer makes payment before the date provided for shutoff of service, the customer shall not be considered to be in default but shall remain in the SPP. If the SPP Customer makes payment after this date, the SPP Customer shall be in default and shall be removed from the SPP. The customer shall be subject to shutoff, provided the 24-hour notice was made by the Company.

E. Participation in Other Shutoff Protection Plans

Customers eligible to participate under the Winter Protection Plan, Rules R 460.131 and R 460.132, will be required to waive their rights to participate under the Winter Protection Plan in order to participate in the Plan. Upon enrollment, the Company shall send written confirmation of the enrollment terms and include notice of this provision.

C5.5 Non-Transmitting Meter Provision

Customers served on Residential Service Secondary Rates RS and General Service Secondary Rates GS have the option to choose a non-transmitting meter. In order for a customer to be eligible to participate in the Non-Transmitting Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

Customers electing a non-transmitting meter will pay the following charges per premises or billing meter:

Up Front Charge:	$ *155.35* ~~69.39~~	a one-time charge per billing meter per request if the notice is given before the transmitting meter is installed
	OR	
	$*223.52* ~~123.91~~	a one-time charge per billing meter per request if the notice is given after the transmitting meter is installed
Monthly Charge:	$ *5.68* ~~9.72~~	per month at each premises as defined in Rule B1., Technical Standards for Electric Service. Multiple metered units shall be charged per billing meter.

All standard charges and provisions of the customer's applicable tariff shall apply.

(Continued on Sheet No. C-32.30)

See Brege Testimony, Page 2, Lines 22-24; Exhibit A-53 (RLB-1) Item #5; Exhibit A-117 (LDW-4), Page 1

M.P.S.C. No. 13- Electric
Consumers Energy Company **Sheet No. C-42.00**

(Continued From Sheet No. C-41.00)

C8. POWER SUPPLY COST RECOVERY (PSCR) CLAUSE (Contd)

A. Applicability of Clause (Contd)

"Power Supply Costs" means those elements of the costs of fuel and purchased and net interchanged power as determined by the Commission to be included in the calculation of the Power Supply Cost Recovery Factor. The Commission determined in its Order in Case No. U-10335 dated May 10, 1994 that the fossil plant emissions permit fees over or under the amount included in base rates charged the Company are an element of fuel costs for the purpose of the clause.

B. Billing

(1) The Power Supply Cost Recovery Factor shall consist of an adjustment factor of ~~1.0805~~ *1.07933* applied to projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a cost base of $0.05570 per kWh (excluding line losses). Average booked costs of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. The average booked costs so determined shall be truncated to the full $0.00001 cost per Kilowatt-hour. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

(2) Each month the Company shall include in its rates a Power Supply Cost Recovery Factor up to the maximum authorized by the Commission as shown on Sheet No. D-4.00.

Should the Company apply lesser factors than those shown on Sheet No. D-4.00, or if the factors are later revised pursuant to Commission Orders or Michigan Compiled Laws, Annotated, 460.6 et seq., the Company shall notify the Commission if necessary and file a revised Sheet No. D-4.00.

C. General Conditions

(1) The power supply and cost review shall be conducted not less than once a year for the purpose of evaluating the Power Supply Cost Recovery Plan filed by the Company and to authorize appropriate Power Supply Cost Recovery Factors. Contemporaneously with its Power Supply Cost Recovery Plan, the Company shall file a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply and projections of Power Supply Costs.

(2) Not more than 45 days following the last day of each billing month in which a Power Supply Cost Recovery Factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the Power Supply Cost Recovery Factor and the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

(3) All revenues collected pursuant to the Power Supply Cost Recovery Factors and the allowance for power included in the base rates are subject to annual reconciliation proceedings.

(Continued on Sheet No. C-43.00)

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #6

(Continued from Sheet No. C-48.64)

C10. RENEWABLE ENERGY PLAN (REP) (Contd)

C10.5 Pilot Solar Program (Contd)

E. Solar Energy Credits

Solar Energy Credits applied to the customer's monthly bill are based on the customer's subscription level, the energy credit and the capacity credit.

The Solar Energy Credits in years one through five will be based on the Short Term Program Energy and Capacity Value and in years six through twenty-five on the sum of the Long Term Program Energy Value and the Long Term Program Capacity Value.

The Long Term Program Energy Value includes a factor to account for avoided line losses attributable to the distributed resource location on the distribution system. The avoided line loss factor is ~~2.71~~ *2.32*%. This value will be revised when line losses are updated in general electric rate cases, as approved by the Commission.

Customers that chose to have the REC sold when this option was initially available will be credited quarterly. The REC credit is based on a Michigan Renewable Portfolio Standard REC value published quarterly in the Midwest Market Notes by Clear Energy Brokerage and Consulting, LLC, or successor publication, multiplied by the RECs generated. Alternatively, the REC value may be based on the actual sale of the RECs.

If the monthly Solar Energy Credit is greater than the customer's bill, the excess credit will be rolled over and applied to the next month's bill. If a Solar Energy Credit accumulates to an amount greater than $100, the Company shall pay the balance to the customer.

F. Reporting

Solar Program production data will be available on the Company's website. Each participating customer's monthly energy bill will include the Subscription Payment and Solar Energy Credit.

The Company will provide quarterly reports to the MPSC detailing the enrollment status and Solar Program production.

G. Cost Recovery

Costs will be recovered as set forth in the Commission Order in Case No. U-17752.

(Continued on Sheet No. C-48.67)

SURCHARGES

Rate Schedule	***IRM Surcharge (Case No. U-20134) Effective for service rendered on and after January 1, 2020 through December 31, 2020***	***IRM Surcharge (Case No. U-20134) Effective for service rendered on and after January 1, 2021 through December 31, 2021***
Rate RSP	*$0.002384/kWh*	*$0.004747 /kWh*
Rate RS	*0.002384/kWh*	*0.004747 /kWh*
Rate RDP	*0.002384/kWh*	*0.004747 /kWh*
Rate RDPR	*0.002384/kWh*	*0.004747 /kWh*
Rate RT	*0.002384/kWh*	*0.004747 /kWh*
Rate REV-1	*0.002384/kWh*	*0.004747 /kWh*
Rate REV-2	*0.002384/kWh*	*0.004747 /kWh*
Rate RSH	*0.002384/kWh*	*0.004747 /kWh*
Rate RPM	*0.002384/kWh*	*0.004747 /kWh*
Rate GS	*0.002218/kWh*	*0.004417/kWh*
Rate GSTU	*0.002218/kWh*	*0.004417/kWh*
Rate GSD	*0.52/kW*	*1.04/kW*
Rate GP		
CVL1	*0.000281/kWh*	*0.000559/kWh*
CVL2	*0.000330/kWh*	*0.000657/kWh*
CVL3	*0.000586/kWh*	*0.001167/kWh*
Rates GPD, GPTU, EIP and GSG-2		
CVL1	*0.03/kW*	*0.06/kW*
CVL2	*0.07/kW*	*0.13/kW*
CVL3	*0.16/kW*	*0.32/kW*
Rate GML	*0.005438/kWh*	*0.010827/kWh*
Rate GUL	*0.005438/kWh*	*0.010827/kWh*
Rate GU-XL	*0.005438/kWh*	*0.010827/kWh*
Rate GU	*0.005438/kWh*	*0.010827/kWh*
Rate PA	*NA*	*NA*
Rate ROA-R	*As in Delivery Rate Schedule*	*As in Delivery Rate Schedule*
Rate ROA-S	*As in Delivery Rate Schedule*	*As in Delivery Rate Schedule*
Rate ROA-P	*As in Delivery Rate Schedule*	*As in Delivery Rate Schedule*

See Collins Testimony, Page 23, Lines 8-23, Page 24, Lines 1-23, Page 25, Lines 1-4; Exhibit A-68 (LMC-5), Pages 1-2

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-2.20**

SURCHARGES

Rate Schedule	***Railway Expense Recovery Effective for the March 2019 Bill Month through August 2019 Bill Month***
Rate RSP	*$0.30/customer*
Rate RS	*0.30/customer*
Rate RDP	*0.30/customer*
Rate RDPR	*0.30/customer*
Rate RT	*0.30/customer*
Rate REV-1	*0.30/customer*
Rate REV-2	*0.30/customer*
Rate GS	*0.76/customer*
Rate GSTU	*0.76/customer*
Rate GSD	*6.83/customer*
Rate GP	*29.61/customer*
Rate GPD	*219.01/customer*
Rate GPTU	*219.01/customer*
Rate EIP	*219.01/customer*
Rate GSG-2	*219.01/customer*
Rate GML	*0.000511/kWh*
Rate GUL	*0.000511/kWh*
Rate GU-XL	*0.000511/kWh*
Rate GU	*0.000511/kWh*
Rate PA	*NA*
Rate ROA-R	*NA*
Rate ROA-S	*NA*
Rate ROA-P	*NA*

See Collins Testimony, Page 25, Lines 5-23 and Page 26, Lines 1-3; Exhibit A-68 (LMC-6) Page 1

RATE CATEGORIES AND PROVISIONS

Description	Full Service	Retail Open Access
RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP		
Residential	*1XXX*	*Not Applicable*
Provisions		
*Residential Summer On-Peak Basic With Income Assistance (RIA) **	*Applicable*	*Not Applicable*
*Residential Summer On-Peak Basic With Senior Citizen (RSC) **	*Applicable*	*Not Applicable*
Peak Power Savers – Air Conditioner Peak Cycling Program	*Applicable*	*Not Applicable*
Peak Power Savers – Universal Peak Reward	*Applicable*	*Not Applicable*
*Residential Summer On-Peak Basic With Self-Generation (SG)***	*1700*	*Not Applicable*
Net Metering Program	*Applicable*	*Not Applicable*
Green Generation Program	*Applicable*	*Not Applicable*
Non-Transmitting Meter Provision	*Not Applicable*	*Not Applicable*
RESIDENTIAL SERVICE SECONDARY RATE RS		
Residential	1000	2000
Provisions		
Residential With Income Assistance (RIA) *	Applicable	Applicable
Residential With Senior Citizen (RSC) *	Applicable	Applicable
Peak Power Savers – Air Conditioner Peak Cycling Program	1005	Not Applicable
Residential With Self-Generation (SG)**	1700	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
RESIDENTIAL SERVICE DYNAMIC PROGRAM		
Peak Power Savers – Critical Peak Time-of-Use (RDP)	1007	Not Applicable
Peak Power Savers – Peak Rewards Time-of-Use (RDPR)	1008	Not Applicable
Provisions		
Residential Dynamic Pricing With Income Assistance (RIA)*	Applicable	*Not* Applicable
Residential Dynamic Pricing With Senior Citizen (RSC)*	Applicable	*Not* Applicable
Residential Dynamic Pricing With Self-Generation (SG)**	1700	Not Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	*Not Applicable*	*Not Applicable*
RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT		
Residential Time-of-Day	1010	2010
Provisions		
Residential Time-of-Day With Income Assistance (RIA) *	Applicable	Applicable
Residential Time-of-Day With Senior Citizen (RSC)*	Applicable	Applicable
Residential Time-of-Day With Self-Generation (SG)**	1705	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	*Not Applicable*	*Not Applicable*

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-~~6.10~~ *6.05*)

See Brege Testimony, Page 3, Lines 14-23 and Page 4, Lines 1-8; Exhibit A-53 (RLB-1) Items #1 and 8

RATE CATEGORIES AND PROVISIONS
(Continued From Sheet No. D-6.00)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Residential Electric Vehicle Service (REV-1)	1020	Not Applicable
Residential Electric Vehicle Service (REV-1) With Self-Generation (SG)**	1710	Not Applicable
Residential Electric Vehicle Service (REV-2)	1030	Not Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	*Not Applicable*	*Not Applicable*

RESIDENTIAL SMART HOURS RATE RSH

Residential	*1XXX*	*Not Applicable*
Provisions		
*Residential Smart Hours With Income Assistance (RIA) **	*Applicable*	*Not Applicable*
*Residential Smart Hours With Senior Citizen (RSC) **	*Applicable*	*Not Applicable*
Peak Power Savers – Air Conditioner Peak Cycling Program	*Applicable*	*Not Applicable*
*Residential Smart Hours With Self-Generation (SG)***	*1700*	*Not Applicable*
Net Metering Program	*Applicable*	*Not Applicable*
Green Generation Program	*Applicable*	*Not Applicable*
Non-Transmitting Meter Provision	*Not Applicable*	*Not Applicable*

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Residential	*1XXX*	*Not Applicable*
Provisions		
*Residential Nighttime Savers With Income Assistance (RIA) **	*Applicable*	*Not Applicable*
*Residential Nighttime Savers With Senior Citizen (RSC) **	*Applicable*	*Not Applicable*
Residential Nighttime Savers With Electric Vehicle Only Charging Credit (REV)	*Applicable*	*Not Applicable*
Peak Power Savers – Air Conditioner Peak Cycling Program	*Applicable*	*Not Applicable*
*Residential Nighttime Savers With Self-Generation (SG)***	*1700*	*Not Applicable*
Net Metering Program	*Applicable*	*Not Applicable*
Green Generation Program	*Applicable*	*Not Applicable*
Non-Transmitting Meter Provision	*Not Applicable*	*Not Applicable*

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-6.10)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-~~6.00~~ *6.05*)

Description	Full Service	Retail Open Access
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial - Temporary Construction Service	1999	Not Applicable
Provisions		
Commercial Billboards/Outdoor Advertising Signs - Dusk to Dawn	Applicable	Not Applicable
Commercial Billboards/Outdoor Advertising Signs - Fixed Hours of Operation	Applicable	Not Applicable
Commercial Miscellaneous	Applicable	Not Applicable
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1715	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU		
Commercial	1121	Not Applicable
Provisions		
Commercial With Educational Institution (GEI)	Applicable	*Not* Applicable
Commercial With Self-Generation (SG) *	1716	Not Applicable
Commercial Resale	*Applicable*	*Not Applicable*
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Commercial (100 kW Billing Demand Guarantee)	1140	2140
Provisions		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1725	Not Applicable
Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG) *	1735	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable

*Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-7.00)

See Brege Testimony, Page 3, Lines 1-13; Exhibit A-53 (RLB-1) Items #1, 3 and 8

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.10)

Description	Full Service	Retail Open Access
GENERAL SERVICE PRIMARY RATE GP		
Commercial (Customer Voltage Level 1, 2 or 3)	1200	2200
Industrial (Customer Voltage Level 1, 2 or 3)	1210	2210
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1745	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1750	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD		
Commercial (Customer Voltage Level 1, 2 or 3)	1220	2220
Industrial (Customer Voltage Level 1, 2 or 3)	1230	2230
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) **	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) **	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) **	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) **	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible –Market Price (GI2)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible – Market Price (GI2)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1755	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1760	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU		
Commercial (Customer Voltage Level 1, 2, or 3)	1280	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3)	1285	Not Applicable
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	*Applicable*	*Not Applicable*
Industrial (Customer Voltage Level 1, 2 or 3) Resale	*Applicable*	*Not Applicable*
Commercial with Education Institution (GEI)	Applicable	Applicable
Industrial with Education Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1765	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1770	Not Applicable
Net Metering Program	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE ENERGY INTENSIVE PRIMARY RATE EIP		
Industrial (Customer Voltage Level 1, 2, or 3)	1250	Not Applicable
Provisions		
Commercial (Customer Voltage Level 1, 2, or 3) With Self-Generation (SG) **	1775	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3) With Self-Generation (SG) **	1780	Not Applicable
Green Generation Program	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with the GEI provision or the Net Metering Program.
** Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-7.10)

See Brege Testimony, Page 3, Lines 1-13; Exhibit A-53 (RLB-1) Items #3 and #8

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 - Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: ***These charges are applicable to Full Service Customers.***

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.062374	*$0.036453*	*$0.098827*	*per kWh for Off-Peak kWh between June 1 and September 30*
$0.092646	*$0.054145*	*$0.146791*	*per kWh for On-Peak kWh between June 1 and September 30*
$0.062374	*$0.036453*	*$0.098827*	*per kWh for all kWh between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: ***These charges are applicable to Full Service Customers.***

System Access Charge:	*$7.50*	*per customer per month*
Distribution Charge:	*$0.048652*	*per kWh for all kWh*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-8.20)

See Brege Testimony, Page 3, Lines 14-23 and Page 4, Lines 1-8; Exhibit A-53 (RLB-1) Item #1; Exhibit A-16 (LMC-3), Page 1

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

(Continued From Sheet No. D-8.10)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(7.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(3.75) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Peak Power Savers:
Customers can elect to participate in both Peak Power Savers programs as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Universal Peak Reward is compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month Both credits will not apply in a single billing month.

Air Conditioner Peak Cycling Program – (Available on a Date to be Announced by the Company):
A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Air Conditioner Peak Cycling Credit may be forfeited for that billing month.

(Continued on Sheet No. D-8.30)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

(Continued From Sheet No. D-8.20)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Air Conditioner Peak Cycling Program: (Contd)

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Power Savers – Air Conditioner Peak Cycling Credit: $(8.00) per customer per month during the billing months of June-September

Universal Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Universal Peak Reward per kWh of incremental energy reductions.

Power Supply Charges: These charges are applicable to Full Service Customers.

Universal Peak Reward $(0.950000) per kWh of incremental energy reduction during a critical peak event between June 1 and September 30

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 550 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-8.40)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

(Continued From Sheet No. D-8.30)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11., Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, June 1 through September 30, including weekday holidays when applicable:

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

RESIDENTIAL SERVICE SECONDARY RATE RS

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

As of January 1, 2020 this rate is only available for customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.061776~~ *0.061770*	$~~0.032749~~ *0.035913*	$~~0.094525~~ *0.097683*	per kWh for the first 600 kWh per month during the billing months of June - September
$~~0.083153~~ *0.081689*	$~~0.044082~~ *0.047494*	$~~0.127235~~ *0.129183*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$~~0.061776~~ *0.061770*	$~~0.032749~~ *0.035913*	$~~0.094525~~ *0.097683*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$~~7.00~~ *7.50*	per customer per month
Distribution Charge:	$~~0.050297~~ *0.048652*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-10.00)

See Brege Testimony, Page 2, Lines 16-22, Page 3, Lines 14-23, Page 5, Lines 1-8; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Page 2

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-9.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(~~7.00~~ *7.50*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Page 2

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-10.00)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(~~3.50~~ *3.75*) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.
Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.
Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-11.10)

See Brege Testimony, Page 2, Lines 16-22 and Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Page 2

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.00)

Monthly Rate: (Contd)

Peak Power Savers – Air Conditioner Peak Cycling Program:

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and have a fully operational AMI meter for purposes of this program. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The participating customer may elect to terminate service for any reason by providing the Company with thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers – Air Conditioner Peak Cycling Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Power Savers – Air Conditioner Peak Cycling Credit: $(*8.00* ~~7.84~~) per customer per month during the billing months of June-September

(Continued on Sheet No. D-11.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-13.01**

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.00)

Monthly Rate:

Option 1 – Peak Power Savers - Critical Peak Time-of-Use Rate (RDP):

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$ ~~0.041976~~ *0.049820*	$ ~~0.017318~~ *0.028966*	$~~0.059294~~ *0.078786*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak – Summer	$ ~~0.058503~~ *0.070884*	$ ~~0.024136~~ *0.041213*	$~~0.082639~~ *0.112097*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak – Summer	$ ~~0.073248~~ *0.090211*	$ ~~0.030219~~ *0.052450*	$~~0.103467~~ *0.142661*	per kWh for all On-Peak kWh ~~during the billing months of June-September between~~ *June 1 and September 30*
Off-Peak – Winter	$ ~~0.057435~~ *0.049820*	$ ~~0.030448~~ *0.028966*	$~~0.087883~~ *0.078786*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak – Winter	$ ~~0.066212~~ *0.062338*	$ ~~0.035101~~ *0.036244*	$~~0.101313~~ *0.098582*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
Critical Peak Event	$ ~~0.614634~~ *0.600732*	$ ~~0.335366~~ *0.349268*	$0.950000	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:-	~~$7.00~~ *7.50*	per customer per month
Distribution Charge:-	$ ~~0.050297~~ *0.048652*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Option 2 – Peak Power Savers - Peak Rewards Time-of-Use Rate RDPR:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	~~$ 0.050762~~ *0.058284*	~~$ 0.026802~~ *0.033886*	~~$0.077564~~ *0.092170*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak-Summer	~~$ 0.070748~~ *0.082665*	~~$ 0.037354~~ *0.048061*	~~$0.108102~~ *0.130726*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak-Summer	~~$ 0.088580~~ *0.105021*	~~$ 0.046769~~ *0.061059*	~~$0.135349~~ *0.166080*	per kWh for all On-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Off-Peak-Winter	~~$ 0.057435~~ *0.049820*	~~$ 0.030448~~ *0.028966*	~~$0.087883~~ *0.078786*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak -Winter	~~$ 0.066212~~ *0.062338*	~~$ 0.035101~~ *0.036244*	~~$0.101313~~ *0.098582*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
Critical Peak Reward	$(~~0.614634~~) *(0.600732)*	$(~~0.335366~~) *(0.349268)*	$(0.950000)	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.02)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 3-4

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.01)

Monthly Rate: (Contd)

Option 2 – Peak Power Savers – Peak Rewards Time-of-Use Rate RDPR: (Contd)

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$~~7.00~~ *7.50*	per customer per month
Distribution Charge:	$~~0.050297~~ *0.048652*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(~~7.00~~ *7.50*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(~~3.50~~ *3.75*) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

(Continued on Sheet No. D-13.03)

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.02)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

(Continued on Sheet No. D-13.04)

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #10

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Availability:

The Experimental Residential Plug-In Electric Vehicle Charging Program is a voluntary pilot available to Full Service residential customers. Upon enrollment of the customer in the program, the customer may take service under one of the following options as applicable:

Option 1 - Residential Home and Plug-in Electric Vehicle Time-of-Day Rate (REV-1) – Level 1 or Level 2 Charging of an electric vehicle combined with household electric usage such as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration or lighting based upon on-peak, mid-peak and off-peak periods and through a single meter.

Option 2 - Residential Plug-In Electric Vehicle Only Time-of-Day Rate (REV-2) – Level 2 Charging of the electric vehicle based upon on-peak, mid-peak and off-peak periods through a separate meter. Electric usage for the household will be billed under the RS or RT Rate Schedule.

"Level 1 Charging" is defined as voltage connection of 120 volts and a maximum load of 12 amperes or 1.4 kVA.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

"Electric Vehicle Supply Equipment (EVSE)" is defined as the conductors, including the ungrounded, grounded and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of delivering energy from the premise wiring to the electric vehicle.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for program.

The total connected load of the home including the electric vehicle charging shall not exceed 10 kW, without the specific consent of the Company.

Customers shall not back-feed or transmit stored energy from the electric vehicle's battery to the Company's distribution system.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service.

Monthly Rate:

Option 1 – REV-1:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$ ~~0.054896~~ *0.054931*	$ ~~0.029061~~ *0.031937*	$~~0.083957~~ *0.086868*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak – Summer	$ ~~0.076510~~ *0.078155*	$ ~~0.040502~~ *0.045440*	$~~0.117012~~ *0.123595*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak – Summer	$ ~~0.095794~~ *0.099465*	$ ~~0.050711~~ *0.057830*	$~~0.146505~~ *0.157295*	per kWh for all On-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Off-Peak – Winter	$ ~~0.054896~~ *0.054931*	$ ~~0.029061~~ *0.031937*	$~~0.083957~~ *0.086868*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak – Winter	$ ~~0.063285~~ *0.068734*	$ ~~0.033502~~ *0.039962*	~~$0.096787~~ *0.108696*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.20)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.10)

Monthly Rate (Contd)

Option 1 – REV – 1 (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$~~7.00~~ *7.50*	per customer per month
Distribution Charge:	$~~0.050297~~ *0.048652*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-13.25)

See Brege Testimony, Page 2, Lines 16-22 and Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Items #9 and 10; Exhibit A-16 (LMC-3), Page 5

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.20)

Monthly Rate (Contd)

Option 2 - REV-2:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$ ~~0.054896~~ *0.054931*	$ ~~0.029061~~ *0.031937*	$~~0.083957~~ *0.086868*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak – Summer	$ ~~0.076510~~ *0.078155*	$ ~~0.0405020~~ *0.045440*	$~~0.117012~~ *0.123595*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak – Summer	$ ~~0.095794~~ *0.099465*	$ ~~0.050711~~ *0.057830*	$~~0.146505~~ *0.157295*	per kWh for all On-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Off-Peak – Winter	$ ~~0.054896~~ *0.054931*	$ ~~0.029061~~ *0.031937*	$~~0.083957~~ *0.086868*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak – Winter	$ ~~0.063285~~ *0.068734*	$ ~~0.033502~~ *0.039962*	$~~0.096787~~ *0.108696*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers

Distribution Charge: $~~0.050297~~ *0.048652* for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10. The REP Surcharge shown on Sheet No. D-2.10 shall not apply.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-13.30)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

Availability:

Subject to any restrictions, this rate is available to any residential customer desiring electric service who chooses to have their electric consumption metered based upon on-peak and off-peak periods. In addition, this rate is available to customers desiring electric service for electric vehicle battery charging where such service is in addition to all other household requirements. Battery charging service is limited to four-wheel vehicles licensed for operation on public streets and highways. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

Service under this rate is limited to 10,000 customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

	Non-Capacity	Capacity	Total	
On-Peak - Summer	$~~0.81273~~ *0.079745*	$~~0.031800~~ *0.046364*	$~~0.113073~~ *0.126109*	per kWh for all On-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Off-Peak - Summer	$~~0.056314~~ *0.054774*	$~~0.022034~~ *0.031846*	$~~0.078348~~ *0.086620*	per kWh for all Off-Peak kWh ~~during the billing months of June – September~~ *between June 1 and September 30*
On-Peak - Winter	$~~0.065553~~ *0.066639*	$~~0.025649~~ *0.038744*	$~~0.091202~~ *0.105383*	per kWh for all On-Peak kWh ~~during the billing months of October – May~~ *between October 1 and May 31*
Off-Peak - Winter	$~~0.058255~~ *0.058363*	$~~0.022794~~ *0.033932*	$~~0.081049~~ *0.092295*	per kWh for all Off-Peak kWh ~~during the billing months of October – May~~ *between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

System Access Charge: $~~7.00~~ *7.50* per customer per month

Distribution Charge: $~~0.050297~~ *0.048652* per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102 Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(~~7.00~~ *7.50*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-15.00)

RESIDENTIAL SERVICE TIME-OF-DAY-SECONDARY RATE RT

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principle Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Senior Citizen Credit: $(~~3.50~~ *3.75*) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-16.00)

RESIDENTIAL SMART HOURS RATE

Availability:

The Residential Smart Hours Rate will be available on a date to be announced by the Company.

Subject to any restrictions, this rate is available to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's expense. By selecting this rate schedule, the customer agrees to provide and email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Customers are able to manage electric costs by reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. During a critical peak event, customers on the Residential Smart Hours Rate will be credited the Universal Peak Reward per kWh of incremental energy reductions.

The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

	Non-Capacity	*Capacity*	*Total*	
Off-Peak - Summer	*$0.060495*	*$0.035172*	*$0.095667*	*per kWh for all Off-Peak kWh between June 1 and September 30*
On-Peak - Summer	*$0.089856*	*$0.052243*	*$0.142099*	*per kWh for all On-Peak kWh between June 1 and September 30*
Off-Peak - Winter	*$0.060495*	*$0.035172*	*$0.095667*	*per kWh for all Off-Peak kWh between October 1 and May 31*
On-Peak - Winter	*$0.067925*	*$0.039492*	*$0.107417*	*per kWh for all On-Peak kWh between October 1 and May 31*

Universal Peak Reward *$(0.950000)* *per kWh of incremental energy reduction during a critical peak event between June 1 and September 30*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge: *$7.50* *per customer per month*

Distribution Charge: *$0.048652* *per kWh for all kWh for a Full Service customer*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102 Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges : These charges are applicable to Full Service Customers.

Income Assistance Credit: *$(7.50)* *per customer per month*

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-16.20)

RESIDENTIAL SMART HOURS RATE

(Continued From Sheet No. D-16.10)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principle Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: *$(3.75)* *per customer per month*

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Peak Power Savers – Air Conditioner Peak Cycling Program – (Available on a Date to be Announced by the Company):

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers Credit may be forfeited for that billing month.

Peak Power Savers – Air Conditioner Peak Cycling Program: (Contd)

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Power Savers – Air Conditioner Peak Cycling Credit: *$(8.00)* *per customer per month during the billing months of June-September*

The customer's incremental energy savings earned under the Universal Peak Reward will be compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not be applied in a single billing month.

(Continued on Sheet No. D-16.30)

See Brege Testimony, Page 4, Lines 9-22 and Page 5, Lines 4-12; Exhibit A-53 (RLB-1) Item #1; Exhibit A-16 (LMC-3), Page 8

RESIDENTIAL SMART HOURS RATE

(Continued From Sheet No. D-16.20)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of 550 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

(Continued on Sheet No. D-16.40)

See Brege Testimony, Page 4, Lines 9-22; Exhibit A-53 (RLB-1) Item #1

RESIDENTIAL SMART HOURS RATE

(Continued From Sheet No. D-16.30)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30
Winter: October 1 through May 31

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

RESIDENTIAL NIGHTTIME SAVERS RATE

Availability:

The Residential Nighttime Savers Rate will be available on a date to be announced by the Company.

The Residential Nighttime Savers Rate is voluntary and available to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense. By selecting this rate schedule, the customer agrees to provide an email address.

Customers taking service on the Residential Nighttime Savers Rate are able to manage electric costs by reducing load during high cost pricing periods and shifting load from high cost pricing periods to lower cost pricing periods. During a critical peak event, customers on the Residential Nighttime Savers Rate will be credited the Universal Peak Reward per kWh of incremental energy reductions.

The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Super Off-Peak - Summer	*$0.052419*	*$0.030477*	*$0.082896*	*per kWh for all Off-Peak kWh between June 1 and September 30*
Off-Peak - Summer	*$0.073762*	*$0.042886*	*$0.116648*	*per kWh for all Mid-Peak kWh between June 1 and September 30*
On-Peak - Summer	*$0.092077*	*$0.053534*	*$0.145611*	*per kWh for all On-Peak kWh between June 1 and September 30*
Super Off-Peak – Winter	*$0.052419*	*$0.030477*	*$0.082896*	*per kWh for all Off-Peak kWh between June 1 and September 30*
Off-Peak - Winter	*$0.065077*	*$0.037836*	*$0.102913*	*per kWh for all Off-Peak kWh between October 1 and May 31*
On-Peak - Winter	*$0.067731*	*$0.039379*	*$0.107110*	*per kWh for all On-Peak kWh between October 1 and May 31*

Universal Peak Reward *$(0.950000)* *per kWh of incremental energy reduction during a critical peak event between June 1 and September 30*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-17.10)

See Brege Testimony, Page 4, Lines 9-22; Exhibit A-53 (RLB-1) Item #1; Exhibit A-16 (LMC-3), Page 9

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.00)

Monthly Rate: (Contd)

Delivery Charges: *These charges are applicable to Full Service Customers.*

System Access Charge:	$7.50	per customer per month
Distribution Charge:	$0.048652	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: *These charges are applicable to Full Service Customers.*

Income Assistance Credit: $(7.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: *These charges are applicable to Full Service Customers.*

Senior Citizen Credit: $(3.75) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the household will be billed under the Residential Summer On-Peak Basic Rate or the Residential Smart Hours Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

Delivery Charges: *These charges are applicable to Full Service Customers.*

Residential Plug-In Electric Vehicle Only Credit: $(7.50) per customer per month

(Continued on Sheet No. D-17.20)

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.10)

Monthly Rate: (Contd)

Peak Power Savers – Air Conditioner Peak Cycling Program:

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and have a fully operational AMI meter for purposes of this program. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Power Savers – Air Conditioner Peak Cycling Credit:	*$(8.00)*	*per customer per month during the billing months of June-September*

The customer's incremental energy savings earned under the Universal Peak Reward will be compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not be applied in a single billing month.

(Continued on Sheet No. D-17.30)

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.20)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 550 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-17.40)

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.30)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	*Super Off-Peak Hours:*	*11:00 PM to 6:00 AM*
(2)	*Off-Peak Hours:*	*6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM*
(3)	*On-Peak Hours:*	*2:00 PM to 7:00 PM*

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.064823~~ *0.063270*	$~~0.031976~~ *0.035652*	$~~0.096799~~ *0.098922*	per kWh for all kWh during the billing months of June-September
$~~0.062199~~ *0.062629*	$~~0.030682~~ *0.035291*	$~~0.092881~~ *0.097920*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) Customers.

System Access Charge: $20.00 per customer per month

Distribution Charge: $~~0.042598~~ *0.043954* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-19.00)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Page 10

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-18.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: $*(0.000753)* ~~(0.000708)~~ per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

(Continued on Sheet No. D-19.10)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-19.00)

Monthly Rate: (Contd)

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11, Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11, Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C10.2, Green Generation Program.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #10

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability:

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.059790~~ *0.056440*	$~~0.029494~~ *0.031804*	$~~0.089284~~ *0.088244*	per kWh for all Off-Peak kWh during the billing months of June - September
Mid-Peak - Summer	$~~0.090451~~ *0.087862*	$~~0.044618~~ *0.049510*	$~~0.135069~~ *0.137372*	per kWh for all Mid-Peak kWh during the billing months of June - September
On-Peak - Summer	$~~0.113249~~ *0.111819*	$~~0.055864~~ *0.063009*	$~~0.169113~~ *0.174828*	per kWh for all On-Peak kWh during the billing months of June - September
Off-Peak - Winter	$~~0.051063~~ *0.051584*	$~~0.025189~~ *0.029067*	$~~0.076252~~ *0.080651*	per kWh for all Off-Peak kWh during the billing months of October - May
On-Peak - Winter	$~~0.057461~~ *0.058899*	$~~0.028345~~ *0.033189*	$~~0.085806~~ *0.092088*	per kWh for all On-Peak kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$~~0.042598~~ *0.043954*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-21.20)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-21.10)

Monthly Rate: (Contd)

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year' Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November, and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1) Off-Peak Hours: 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2) Mid-Peak Hours: 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3) On-Peak Hours: 2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1) Off-Peak Hours: 11:00 PM to 7:00 AM
(2) On-Peak Hours: 7:00 AM to 11:00 PM

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Education Institution Credit: $(~~0.000708~~ *0.000753*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C 1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self -generated will be charged as described in the Delivery Charges section of this Rate Schedule.

(Continued on Sheet No. D-21.30)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-21.20)

Monthly Rate: (Contd)

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/ billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C10.2, Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service customers.

~~Capacity~~ *Peak Demand* Charge:

Non-Capacity	*Capacity*	*Total*	
$8.15	$~~12.17~~ *13.41*	*$21.56*	per kW for all kW of Peak Demand during the billing months of June-September
$6.15	$~~10.17~~ *11.41*	*$17.56*	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.066606~~ *0.043337*	per kWh for all kWh during the billing months of June-September.
$~~0.061437~~ *0.041030*	per kWh for all kWh during the billing months of October-May.

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.15	per kW for all kW of Peak Demand
Distribution Charge:	$~~0.035114~~ *0.031730*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-23.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD
(Continued From Sheet No. D-23.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit: $(~~0.000619~~ *0.000621*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

(Continued on Sheet No. D-24.10)

See Brege Testimony, Page 2, Lines 16-22 and Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Items #9 and 10; Exhibit A-16 (LMC-3), Page 12

GENERAL SERVICE PRIMARY RATE GP

Availability:

Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.059560~~	$~~0.041426~~	$~~0.100986~~	per kWh for all kWh during the billing months of June-September
0.057042	*0.039192*	*0.096234*	
$~~0.057461~~	$~~0.040061~~	$~~0.097522~~	per kWh for all kWh during the billing months of October-May
0.056535	*0.038866*	*0.095401*	

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.053860~~	$~~0.035726~~	$~~0.089586~~	per kWh for all kWh during the billing months of June-September
0.051132	*0.033282*	*0.084414*	
$~~0.051761~~	$~~0.034361~~	$~~0.086122~~	per kWh for all kWh during the billing months of October-May
0.050625	*0.032956*	*0.083581*	

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.051860~~	$~~0.033726~~	$~~0.085586~~	per kWh for all kWh during the billing months of June-September
0.050042	*0.032192*	*0.082234*	
$~~0.049761~~	$~~0.032361~~	$~~0.082122~~	per kWh for all kWh during the billing months of October-May
0.049535	*0.031866*	*0.081401*	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-27.10)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 13-15

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27.00)

Monthly Rate (Contd)

Delivery Charges - These charges are applicable to Full Service and Retail Open Access (ROA) Customers.

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)

Distribution Charge: $~~0.017201~~ *0.013698* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL 2)

Distribution Charge: $~~0.010745~~ *0.007784* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)

Distribution Charge: $~~0.007861~~ *0.005784* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-28.00)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 13-15

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27.10)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.

Substation Ownership Credit: $ (~~0.000393~~ *0.000289*) per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “school” shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. “College” or “University” shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: $(~~0.000530~~ *0.000514*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

(Continued on Sheet No. D-29.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-28.00)

Monthly Rate (Contd)

Self-Generation Provision (SG) (Contd):

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate shall require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, or (v) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #10

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Demand Charge:

Non-Capacity	Capacity	Total	
$~~7.86~~ *9.78*	$~~12.52~~ *16.85*	$~~20.38~~ *26.63*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~7.86~~ *8.78*	$~~11.52~~ *15.85*	$~~19.38~~ *24.63*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$~~1.86~~ *6.95*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~1.86~~ *6.95*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.053889~~ *0.038439*	per kWh for all On-Peak kWh during the billing months of June-September
$~~0.038016~~ *0.027376*	per kWh for all Off-Peak kWh during the billing months of June-September
$~~0.043953~~ *0.032664*	per kWh for all On-Peak kWh during the billing months of October-May
$~~0.039917~~ *0.029477*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-31.05)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Page 18

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service customers. (Contd)

Charges for Customer Voltage Level 2 (CVL2)

Demand Charge:

Non- Capacity	Capacity	Total	
$~~7.86~~ *8.78*	$~~11.52~~ *15.85*	$~~19.38~~ *24.63*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~7.86~~ *7.78*	$~~10.52~~ *14.85*	$~~18.38~~ *22.63*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$~~1.86~~ *6.68*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~1.86~~ *6.68*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.048189~~ *0.032529*	per kWh for all On-Peak kWh during the billing months of June-September
$~~0.032316~~ *0.021466*	per kWh for all Off-Peak kWh during the billing months of June-September
$~~0.038253~~ *0.026754*	per kWh for all On-Peak kWh during the billing months of October-May
$~~0.034217~~ *0.023567*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Demand Charge:

Non-Capacity	Capacity	Total	
$~~7.86~~ *7.78*	$~~10.52~~ *14.85*	$~~18.38~~ *22.63*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~7.86~~ *6.78*	$~~9.52~~ *13.85*	$~~17.38~~ *20.63*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$~~1.86~~ *6.55*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~1.86~~ *6.55*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.046189~~ *0.031439*	per kWh for all On-Peak kWh during the billing months of June-September
$~~0.030316~~ *0.020376*	per kWh for all Off-Peak kWh during the billing months of June-September
$~~0.036253~~ *0.025664*	per kWh for all On-Peak kWh during the billing months of October-May
$~~0.032217~~ *0.022477*	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-31.10)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.05)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$ ~~4.21~~ *3.80*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$ ~~1.90~~ *1.93*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$ ~~1.06~~ *0.98*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-32.00)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 16-18

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.10)

Monthly Rate (Contd)

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the preceding billing months of June through September, nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(~~0.65~~ *0.96*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(~~0.38~~ *0.46*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-33.00)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 16-17

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-32.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP)

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: $(~~0.000296~~ *0.000314*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-34.00)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 16-18

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-33.00)

Monthly Rate (Contd)

Self-Generation Provision (SG)

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Interruptible Service Provision (GI)

This provision is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed ~~75,000~~ *100,000* kW. Customers shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 300,000 kW.

Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

(Continued on Sheet No. D-34.10)

See Brege Testimony, Page 6, Lines 18-22 and Page 7, Lines 1-6; Exhibit A-53 (RLB-1) Items #10 and 11

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.00)

Monthly Rate (Contd)

Interruptible Service Provision (GI) (Contd)

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate. All contracts under this provision shall be negotiated on an annual basis. The Customer must notify the Company by December 31st of each year of their desire to renew the GI provision and the amount of interruptible kW for the following *capacity planning* year *(June 1 through May 31)*. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

The minimum On-Peak Billing Demand that shall be billed for the interruptible portion of a customer's bill is the contracted interruptible amount. At the Company's discretion, the customer may reduce the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements *for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity* ~~as determined by the Company~~.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide *the Customer at least thirty minutes advance* notice ~~in advance~~ of ~~probable~~ *a required* interruption, and if possible, a second notice ~~of positive interruption~~. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $50.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges - These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

(Continued on Sheet No. D-*34.20* ~~35.00~~)

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #11

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.10)

Interruptible Service Provision – Market-Price Option (GI2)

Availability:

This provision is available to any Full Service GPD customer account willing to contract for at least 3,000 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to contract for less than the minimum contract capacity amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contract Capacity

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December 31st of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

Monthly Billing

For billing purposes, the monthly firm service will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)

LMP Energy Charge:	*MISO Real-Time LMP per kWh for all kWh*	
Capacity & Transmission Charge:	*$0.047607*	*per kWh for all kWh during the billing months of June-September*
	$0.043987	*per kWh for all kWh during the billing months of October-May*

Charges for Customer Voltage Level 2 (CVL 2)

LMP Energy Charge:	*MISO Real-Time LMP per kWh for all kWh*	
Capacity & Transmission Charge:	*$0.035317*	*per kWh for all kWh during the billing months of June-September*
	$0.031698	*per kWh for all kWh during the billing months of October-May*

Charges for Customer Voltage Level 1 (CVL 1)

LMP Energy Charge:	*MISO Real-Time LMP per kWh for all kWh*	
Capacity & Transmission Charge:	*$0.032914*	*per kWh for all kWh during the billing months of June-September*
	$0.029295	*per kWh for all kWh during the billing months of October-May*

(Continued on Sheet No. D-34.30)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.20)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	*Low Side*
Customer Voltage Level 1	*0.000%*	*0.705%*
Customer Voltage Level 2	*1.271%*	*2.366%*
Customer Voltage Level 3	*3.221%*	*7.643%*

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: *$100.00 per additional meter installation per month*

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10. as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-34.40)

See Brege Testimony, Page 6, Lines 18-22 and Page 7, Lines 1-2; Exhibit A-53 (RLB-1) Item #12

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.30)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $10.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-35.00)

See Brege Testimony, Page 6, Lines 18-22 and Page 7, Lines 1-2; Exhibit A-53 (RLB-1) Item #12

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-~~34.10~~ *34.40*)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate shall require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, or (vi)at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #12

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-36.20**

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.10)

Monthly Rate:

Power Supply Charges

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.055686~~ *0.051305*	$~~0.019871~~ *0.022737*	$~~0.075557~~ *0.074042*	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.073172~~ *0.066262*	$~~0.024306~~ *0.028050*	$~~0.097478~~ *0.094312*	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.087538~~ *0.080438*	$~~0.027950~~ *0.033085*	$~~0.115488~~ *0.113523*	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.093628~~ *0.090655*	$~~0.029495~~ *0.036714*	$~~0.123123~~ *0.127369*	per kWh during the calendar months of June – September
Off-Peak - Winter	$~~0.055049~~ *0.051873*	$~~0.019709~~ *0.022939*	$~~0.074758~~ *0.074812*	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.061891~~ *0.058080*	$~~0.021444~~ *0.025144*	$~~0.083335~~ *0.083224*	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.064759~~ *0.059588*	$~~0.022171~~ *0.025680*	$~~0.086930~~ *0.085268*	per kWh during the calendar months of October – May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.049986~~ *0.046305*	$~~0.014171~~ *0.017737*	$~~0.064157~~ *0.064042*	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.067472~~ *0.061262*	$~~0.018606~~ *0.023050*	$~~0.086078~~ *0.084312*	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.081838~~ *0.075438*	$~~0.022250~~ *0.028085*	$~~0.104088~~ *0.103523*	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.087928~~ *0.085655*	$~~0.023795~~ *0.031714*	$~~0.111723~~ *0.117369*	per kWh during the calendar months of June – September
Off-Peak - Winter	$~~0.049349~~ *0.046873*	$~~0.014009~~ *0.017939*	$~~0.063358~~ *0.064812*	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.056191~~ *0.053080*	$~~0.015744~~ *0.020144*	$~~0.071935~~ *0.073224*	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.059059~~ *0.054588*	$~~0.016471~~ *0.020680*	$~~0.075530~~ *0.075268*	per kWh during the calendar months of October – May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.047986~~ *0.044305*	$~~0.012171~~ *0.015737*	$~~0.060157~~ *0.060042*	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.065472~~ *0.059262*	$~~0.016606~~ *0.021050*	$~~0.082078~~ *0.080312*	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.079838~~ *0.073438*	$~~0.020250~~ *0.026085*	$~~0.100088~~ *0.099523*	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.085928~~ *0.083655*	$~~0.021795~~ *0.029714*	$~~0.107723~~ *0.113369*	per kWh during the calendar months of June – September
Off-Peak - Winter	$~~0.047349~~ *0.044873*	$~~0.012009~~ *0.015939*	$~~0.059358~~ *0.060812*	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.054191~~ *0.051080*	$~~0.013744~~ *0.018144*	$~~0.067935~~ *0.069224*	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.057059~~ *0.052588*	$~~0.014471~~ *0.018680*	$~~0.071530~~ *0.071268*	per kWh during the calendar months of October – May

Delivery Charges

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $~~4.21~~ *3.80* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $~~1.90~~ *1.93* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $~~1.06~~ *0.98* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-36.30)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 19-21

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.20)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.
The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(~~0.65~~ *0.96*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(~~0.38~~ *0.46*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.
The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit: $(~~0.000296~~ *0.000314*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-36.40)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.30)

Self-Generation Provision (SG)

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate shall require a written contract with a minimum term of one year.

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #10

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.00)

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:

Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	3:00 PM to 5:00 PM during a Critical Peak Event

Winter:

Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	5:00 PM to 7:00 PM during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.038946~~ *0.050003*	$~~0.007688~~ *0.002879*	$~~0.046634~~ *0.052882*	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.050273~~ *0.069976*	$~~0.013375~~ *0.003245*	$~~0.063648~~ *0.073221*	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.059579~~ *0.086536*	$~~0.018047~~ *0.003548*	$~~0.077626~~ *0.090084*	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.063363~~ *0.093021*	$~~0.019947~~ *0.003667*	$~~0.083310~~ *0.096688*	per kWh during the calendar months of June – September
Critical Peak - Summer		the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September		
Off-Peak - Winter	$~~0.040009~~ *0.050262*	$~~0.008222~~ *0.002884*	$~~0.048231~~ *0.053146*	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.049444~~ *0.070667*	$~~0.012959~~ *0.003258*	$~~0.062402~~ *0.073925*	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.059804~~ *0.089238*	$~~0.018160~~ *0.003598*	$~~0.077964~~ *0.092836*	per kWh during the calendar months of October – May
Critical Peak - Winter		the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May		

(Continued on Sheet No. D-37.20)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.10)

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.033246~~ *0.053003*	$~~0.018688~~ *0.005879*	$~~0.051934~~ *0.058882*	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.044573~~ *0.072976*	$~~0.024375~~ *0.006245*	$~~0.068948~~ *0.079221*	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.053879~~ *0.089536*	$~~0.029047~~ *0.006548*	$~~0.082926~~ *0.096084*	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.057663~~ *0.096021*	$~~0.030947~~ *0.006667*	$~~0.088610~~ *0.102688*	per kWh during the calendar months of June – September
Critical Peak - Summer		the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September		
Off-Peak - Winter	$~~0.034309~~ *0.053262*	$~~0.019222~~ *0.005884*	$~~0.053531~~ *0.059146*	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.043744~~ *0.073667*	$~~0.023959~~ *0.006258*	$~~0.067702~~ *0.079925*	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.054104~~ *0.092238*	$~~0.029160~~ *0.006598*	$~~0.083264~~ *0.098836*	per kWh during the calendar months of October – May
Critical Peak - Winter		the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May		

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.031246~~ *0.048003*	$~~0.015688~~ *0.000879*	$~~0.046934~~ *0.048882*	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.042573~~ *0.067976*	$~~0.021375~~ *0.001245*	$~~0.063948~~ *0.069221*	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.051879~~ *0.084536*	$~~0.026047~~ *0.001548*	$~~0.077926~~ *0.086084*	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.055663~~ *0.091021*	$~~0.027947~~ *0.001667*	$~~0.083610~~ *0.092688*	per kWh during the calendar months of June – September
Critical Peak - Summer		the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September		
Off-Peak - Winter	$~~0.032309~~ *0.048262*	$~~0.016222~~ *0.000884*	$~~0.048531~~ *0.049146*	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.041744~~ *0.068667*	$~~0.020959~~ *0.001258*	$~~0.062702~~ *0.069925*	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.052104~~ *0.087238*	$~~0.026160~~ *0.001598*	$~~0.078264~~ *0.088836*	per kWh during the calendar months of October – May
Critical Peak - Winter		the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May		

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3):

Capacity Charge: $~~4.21~~ *3.80* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2):

Capacity Charge: $~~1.90~~ *1.93* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1):

Capacity Charge: $~~1.06~~ *0.98* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-37.30)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Pages 22-24

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.20)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(~~0.65~~ *0.96*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(~~0.38~~ *0.46*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

(Continued on Sheet No. D-37.40)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.30)

Self-Generation Provision (SG) (Contd)

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data /billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written contract with a minimum term of one year.

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-42.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company , the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer’s consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of 2.04% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~0.690~~ *0.705*%
Customer Voltage Level 2	~~1.390~~ *1.271* %	~~2.480~~ *2.366*%
Customer Voltage Level 3	~~3.660~~ *3.221*%	~~7.900~~ *7.643*%

Delivery Standby Charges

System Access Charge:

Generator that does not meet or exceed load:	$100.00	per generator installation per month
Generator that meets or exceeds load:	$200.00	per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)
Capacity Charge: $ ~~4.21~~ *3.80* per kW of Standby Demand

Charges for Customer Voltage Level 2 (CVL 2)
Capacity Charge: $ ~~1.90~~ *1.93* per kW of Standby Demand

Charges for Customer Voltage Level 1 (CVL 1)
Capacity Charge: $ ~~1.06~~ *0.98* per kW of Standby Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-44.00)

See Brege Testimony, Page 2, Lines 16-22 and Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Items #6 and 9; Exhibit A-16 (LMC-3), Page 25

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-43.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.
The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(~~0.65~~ *0.96*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(~~0.38~~ *0.46*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-45.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2
(Continued From Sheet No. D-44.00)

Monthly Rate(Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit: $ (~~1.06~~ *0.98*)per kW of Standby Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year.

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.050986~~ *0.070483*	$0.000000	$~~0.050986~~ *0.070483*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-46.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge: $10.00 per customer per month

Distribution Charge: $~~0.065052~~ *0.064457* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.025022~~ *0.034590*	$0.000000	$~~0.025022~~ *0.034590*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Primary Delivery Charge

System Access Charge: $20.00 per customer per month

Distribution Charge: $~~0.049217~~ *0.049108* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-48.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-50.10)

Monthly Rate

The charge per luminaire per month shall be:

Type of Luminaire	Nominal Rating of Lamps (One Lamp per Luminaire) [1] Watts	Ballast [2] (Watts Including Ballast)	Lumens	Service Charge per Luminaire [4] Capacity	Non-Capacity	Total	Fixture Charge per Luminaire [4]
Mercury Vapor [3]	100	128	3,500	$~~7.71~~ *8.94*	0.00	$~~7.71~~ *8.94*	$6.00
Mercury Vapor [3]	175	209	7,500	~~12.59~~ *14.60*	0.00	~~12.59~~ *14.60*	6.00
Mercury Vapor [3]	250	281	10,000	~~16.93~~ *19.63*	0.00	~~16.93~~ *19.63*	6.00
Mercury Vapor [3]	400	458	20,000	~~27.59~~ *31.99*	0.00	~~27.59~~ *31.99*	6.00
Mercury Vapor [3]	700	770	35,000	~~46.39~~ *53.78*	0.00	~~46.39~~ *53.78*	6.00
Mercury Vapor [3]	1,000	1,080	50,000	~~65.07~~ *75.43*	0.00	~~65.07~~ *75.43*	6.00
High-Pressure Sodium [3]	70	83	5,000	~~5.00~~ *5.80*	0.00	~~5.00~~ *5.80*	6.00
High-Pressure Sodium	100	117	8,500	~~7.05~~ *8.17*	0.00	~~7.05~~ *8.17*	6.00
High-Pressure Sodium	150	171	14,000	~~10.30~~ *11.94*	0.00	~~10.30~~ *11.94*	6.00
High-Pressure Sodium [3]	200	247	20,000	~~14.88~~ *17.25*	0.00	~~14.88~~ *17.25*	6.00
High-Pressure Sodium	250	318	24,000	~~19.16~~ *22.21*	0.00	~~19.16~~ *22.21*	6.00
High-Pressure Sodium	400	480	45,000	~~28.92~~ *33.52*	0.00	~~28.92~~ *33.52*	6.00
Fluorescent [3]	380	470	20,000	~~28.32~~ *32.83*	0.00	~~28.32~~ *32.83*	6.00
Incandescent [3]	202	202	2,500	~~12.17~~ *14.11*	0.00	~~12.17~~ *14.11*	6.00
Incandescent [3]	305	305	4,000	~~18.37~~ *21.30*	0.00	~~18.37~~ *21.30*	6.00
Incandescent [3]	405	405	6,000	~~24.40~~ *28.29*	0.00	~~24.40~~ *28.29*	6.00
Incandescent [3]	690	690	10,000	~~41.57~~ *48.19*	0.00	~~41.57~~ *48.19*	6.00
Metal Halide	150	170	9,750	~~10.24~~ *11.87*	0.00	~~10.24~~ *11.87*	6.00
Metal Halide [3]	175	210	10,500	~~12.65~~ *14.67*	0.00	~~12.65~~ *14.67*	6.00
Metal Halide	250	290	15,500	~~17.47~~ *20.25*	0.00	~~17.47~~ *20.25*	6.00
Metal Halide	400	460	24,000	~~27.71~~ *32.13*	0.00	~~27.71~~ *32.13*	6.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For customers who own their lighting fixtures and are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a ~~29.7~~ *34.2*% Power Supply Charge and a ~~70.3~~ *65.8*% Distribution Charge. For customers who do not own their lighting fixtures and are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a ~~18.0~~ *22.5*% Power Supply Charge and a ~~82.0~~ *77.5*% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-52.00)

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.01)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine the type and size of all experimental lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of experimental lighting available under this rate.

E. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered Experimental Lighting option.

F. Any charges, deposits or contributions may be required in advance of commencement of construction.

G. At the Company's discretion, any failed lighting fixtures may be converted to an equivalent LED at no cost to the customer if the customer agrees to the conversion. The replaced fixture will then be moved to General Unmetered Experimental Lighting Rate GU-XL upon completion of the installation.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Power Supply Charges

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.059553~~ *0.047477*	$0.000000	$~~0.059553~~ *0.047477*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges Customer-Owned Option

Distribution Charge:	$~~0.025336~~ *0.117741*	per kWh for all kWh

Delivery Charges Company-Owned Option

Distribution Charge:	$~~0.031076~~ *0.144416*	per kWh for all kWh
Fixture Charge per Luminaire:	$6.00	per month

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting

Unmetered Experimental Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

(Continued on Sheet No. D-54.03)

See Brege Testimony, Page 2, Lines 16-22; Exhibit A-53 (RLB-1) Item #9; Exhibit A-16 (LMC-3), Page 28

GENERAL SERVICE UNMETERED RATE GU

Availability

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate

Power Supply Charges

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.056376~~ *0.051009*	$~~0.018011~~ *0.020081*	$~~0.074387~~ *0.071090*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$~~0.017001~~ *0.017130*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the *Power Plant* Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-55.00)

(Continued From Sheet No. E-5.00)

E2. ROA CUSTOMER SECTION

E2.1 Terms and Conditions of Service

The ROA Service Standards and Rate Schedules set forth the rates, charges, terms and conditions of service for the delivery of Power to a ROA Customer, procured by a Retailer. Such Power shall be initially received at a designated Point of Receipt and ultimately delivered to the ROA Customer's Point of Delivery through the Company's Distribution System.

A customer's eligibility to take ROA Service is subject to the full satisfaction of any terms or conditions imposed by pre-existing contracts or tariffs with the Company.

A ROA Customer will specify only one Retailer at any given time for the supply of Power to each ROA Customer Account or ROA Customer location.

A ROA Customer shall be permitted to change Retailers. The changes will become effective at the completion of their normal billing cycle. A ROA Customer will be assessed a ROA Customer Switching Service Charge (as provided for in the ROA Rate Schedule) per account for each change. The change will be submitted to the Company electronically by the ROA Customer's Retailer as a new enrollment. The Company will notify the ROA Customer’s previous Retailer and new Retailer electronically of the effective date of the switch.

Upon receipt of the enrollment form from the customer's Retailer, the Company shall provide a new Retail Open Access Residential Secondary Rate ROA-R Customer with a pending enrollment with a Retailer a fourteen-day notice period (beginning with the day the Company receives the enrollment from the Retailer) in which the ROA-R Customer may cancel the enrollment before the switch is executed. A Retail Open Access Secondary Rate ROA-S and Retail Open Access Primary Rate ROA-P Customer's right to cancel an enrollment shall be in accordance with the terms of their contract with their Retailer.

A ROA Service Contract may be required in compliance with the Term and Form of Contract provision of the applicable ROA Rate Schedule. Termination of ROA Service for distribution services can be initiated by the ROA Customer in accordance with the written notice and the minimum term of ROA service requirements as provided for in the "Return to Company Full Service" provision in this ROA Customer Section or initiated by the Company with a minimum of 60 days' written notice.

E2.2 Metering

All load served under this tariff shall be separately metered. A ROA Customer receiving electric service with a Maximum Demand of 20 kW or more shall be metered *with a Wireless Under Glass Meter or be* required to install an Interval Data Meter.

A ROA Customer receiving electric service through Company-owned transformation will have varying metering requirements, depending on the ROA Customer's size. The metering requirements for these ROA Customers shall be determined as follows:

ROA Customer Maximum Demand	Required Metering
Less than 20 kW	*Wireless Under Glass Meter,* Energy-Only Registering Meter or Energy and Maximum
20 kW or Greater	*Wireless Under Glass Meter,* Demand Registering Meter Interval Data Meter

(Continued on Sheet No. E-7.00)

(Continued From Sheet No. E-6.00)

E2. ROA CUSTOMER SECTION (Contd)

E2.2 Metering (Contd)

Metering equipment for a ROA Customer shall be furnished, installed, read, maintained and owned by the Company.

For a ROA Customer with an Interval Data Meter *that is not a Wireless Under Glass Meter*, meter reading will be accomplished electronically through a ROA Customer-provided telephone line or other communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems. The communication link must be installed and operating prior to the ROA Customer receiving ROA Service.

A ROA load-profiled customer with maximum demand of 20 kW or less may receive meter reads by conventional means. If the load-profiled account exceeds a maximum demand of 20 kW *and the customer does not have a Wireless Under Glass Meter*, the customer will be required to install a communication line to access the Interval Data Meter electronically in order to continue ROA service if the customer is located in an area where electric Advanced Metering Infrastructure (AMI) transmitting technology meters are not available.

The ROA Customer*, not being metered with a Wireless Under Glass meter* shall obtain a separate telephone line for such purposes paying all charges in connection therewith. The ROA Customer is responsible for assuring the performance of the telephone line or other communication links at the time of meter interrogation for billing purposes. If the Company is unable to access meter data electronically, the Company will retrieve the data manually. If the Company is unable to access meter data electronically for two or more billing months within a 12 month period, the Company will assess a $45 charge for the second and all subsequent manual meter reads unless the inability to access the meter data electronically is the fault of the Company. The ROA Customer will be notified of the $45 manual meter read policy following the first incident requiring a manual meter read within the 12 month period. In the event that the Company is unable to access meter data electronically for three consecutive months, the ROA Customer's ROA Service shall be terminated and the ROA Customer shall be transferred to Company Full Service and be subject to the "Return to Company Full Service" provision unless telephonic access failure is due to non-performance of the telecommunications service provider or the Company. The 60-day notice requirement to terminate the ROA Customer's service does not apply in the event the Company is unable to access the ROA Customer's meter data electronically for three consecutive months and is subsequently returned to Company Full Service. In the event the Company is unable to access the meter data electronically for 12 consecutive months due to non-performance of the telecommunications service provider, the customer will be returned to full service. It is the customer's responsibility to notify the Company the status of any known telephonic communication issues that may inhibit the Company's ability to access meter data electronically.

A hardship exception may be made for cases where installation of both land-line and cellular telephone service is impractical *and a Wireless Under Glass Meter in not an option*. The burden of proving hardship rests on the customer. If the hardship exception is granted, the customer's meter will be manually read once a month, on a date the Company selects, for an additional charge of $45 month.

For *a Wireless Under Glass*, an Energy-Only Registering or Energy and Maximum Demand Registering metered ROA Customer, the meter will be read by conventional means and the ROA Customer will not be required to provide a telephone service or other communication link.

E2.3 Character of Service

A. Refer to the "Nature of Service" provision of the applicable ROA Rate Schedule.

B. The ROA Customer with a monthly-Maximum Demand greater than or equal to 1,000 kW is not required to utilize an Aggregator.

(Continued on Sheet No. E-8.00)

See Brege Testimony, Page 6, Lines 10-17; Exhibit A-53 (RLB-1) Item #13

(Continued From Sheet No. E-19.00)

E3. RETAILER SECTION (Contd)

E3.7 Load Profiling

Retailers with ROA Customers who do not have an Interval Data Meter *or a Wireless Under Glass Meter* shall comply with the following provisions:

A. The Company will provide the Retailer with the rate class profile and applicable loss factor for the Retailer's customers as a basis for scheduling energy with MISO and reporting energy to MISO. The rate class profile will be the most recent profile approved for the Company by the MPSC.

B. Hourly Energy Reporting:

The Retailer or entity serving as the MDMA for the Retailer will report the hourly energy usage determined in (1) below to the MISO as the actual usage for the Retailer in the MISO energy market.

Hourly energy usage for MISO settlement shall be determined as follows:

(1) The Power consumed by the Retailer's ROA Customers shall be determined as the total of (a) and (b) as follows:

(a) For customers with Interval Data Meters *or Wireless Under Glass Meters*, by actual hourly energy usage, adjusted for losses.

(b) For customers with Energy-Only Registering Meters or Energy and Demand Registering Meters, hourly usage data for these customers will be determined by the use of the profile for the customer class to distribute the total weather adjusted usage (actual or estimated) in the billing period across all the hours in that billing period, adjusted for losses.

E3.8 Customer Protections

The maximum early termination fee for residential contracts of one year or less shall not exceed $50. The maximum early termination fee for residential contracts of longer than one year shall not exceed $100. It is the Retailer's responsibility to have a current valid contract with the customer at all times. Any contract that is not signed by the customer or Legally Authorized Person shall be considered null and void. Only the customer account holder or Legally Authorized Person shall be permitted to sign a contract. A Retailer and its agent shall make reasonable inquiries to confirm that the individual signing the contract is a Legally Authorized Person. For each customer, a Retailer must be able to demonstrate that a customer has made a knowing selection of the Retailer by at least one of the following verification records:

(1) An original signature from the customer account holder or Legally Authorized Person.
(2) Independent third party verification with an audio recording of the entire verification call.
(3) An e-mail address if signed up through the Internet.

The Commission or its Staff may request a reasonable number of records from a Retailer to verify compliance with this customer verification provision, and in addition, may request records for any customer due to a dispute.

A Retailer must distribute a confirmation letter to residential customers by U.S. mail. The confirmation letter must be postmarked within seven (7) days of the customer or Legally Authorized Person signing a contract with the Retailer. The confirmation letter must include the date the letter was sent, the date the contract was signed, the term of the contract with end date, the fixed or variable rate charged, the unconditional cancellation period, any early termination fee, the Retailer's phone number, the Commission's toll-free number and the Company's emergency contact information.

See Brege Testimony, Page 6, Lines 10-17; Exhibit A-53 (RLB-1) Item #13

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

Availability:

Subject to any restrictions, this rate is available to any residential customer receiving service at Secondary Voltage for:

(i) delivery of Power from the Point of Receipt to the Point of Delivery,

(ii) any usual residential use as defined in Rule C4.3 A., Residential Usage and Rate Application,

(iii) single-phase or three-phase equipment, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company, and

(iv) service within Company designated service areas.

Service under this rate must be separately metered.

For those ROA Customers that do not have an Interval Data Meter *or a Wireless Under Glass Meter*, all Retailers shall assume that each Residential ROA Customer served under this rate has a Maximum Demand equivalent to 0.78 kW per hundred kWh of monthly use, using the month of maximum monthly consumption that occurred within the last 12 months.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

Metering Requirements:

The load served under this tariff shall be separately metered by Energy-Only Registering Meters of billing quality *or a Wireless Under Glass Meter*. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer may elect an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge in the Company Full Service General Service Secondary Rate GS for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

(Continued on Sheet No. E-23.00)

See Brege Testimony, Page 6, Lines 10-17; Exhibit A-53 (RLB-1) Item #13

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

(Continued From Sheet No. E-22.00)

RETAILER

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of ~~7.239~~ *7.643*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER

Monthly Rate - ROA Customer:

ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge:

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer’s previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule

E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

See Brege Testimony, Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Item #6

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

Availability:

Subject to any restrictions, this rate is available to any Non-Residential customer receiving Secondary Service for:

(i) delivery of Power from the Point of Receipt to the Point of Delivery,

(ii) service within Company designated service areas, and

(iii) resale service in accordance with Rule C4.4, Resale.

This rate is also available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

Service under this rate must be separately metered.

For those ROA Customers that do not have an Interval Data Meter *or a Wireless Under Glass Meter*, all Retailers shall assume that each Secondary ROA Customer served under this rate has a Maximum Demand equivalent to 0.70 kW per hundred kWh of monthly use, using the month of maximum monthly consumption that occurred within the last 12 months.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

When the service is three-phase, 3-wire, lighting may be included, provided the ROA Customer furnishes all transformation facilities required for such purpose, and so arranges the lighting circuits as to avoid excessive unbalance of the three-phase load. Service for the individual capacity of single-phase or three-phase equipment shall not exceed 3 hp or 3 kW, nor does the total connected load exceed 10 kW, without the specific consent of the Company.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

(Continued on Sheet No. E-25.00)

See Brege Testimony, Page 6, Lines 10-17; Exhibit A-53 (RLB-1) Item #13

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

(Continued From Sheet No. E-24.00)

Metering Requirements:

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by *a Wireless Under Glass Meter or* an Energy Registering Meter, with or without maximum demand registers, of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer with a Maximum Demand of less than 20 kW may elect to install an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with a Maximum Demand of 20 kW or more shall be separately metered by *a Wireless Under Glass Meter or* an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER:

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of ~~7.239~~ *7.643*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

(Continued on Sheet No. E-26.00)

See Brege Testimony, Page 6, Lines 10-17 and Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Items #6 and 13

RETAIL OPEN ACCESS PRIMARY RATE ROA-P

Availability:

Subject to any restrictions, this rate is available to any customer receiving service at a Primary Voltage for the delivery of Power from the Point of Receipt to the Point of Delivery and for resale service in accordance with Rule C4.4, Resale.

This rate is not available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer. This ROA Customer must take service under Retail Open Access Secondary Rate ROA-S.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Service under this rate shall be separately metered. The Retailer shall deliver a flat, fixed amount of power every hour of every day.

Any ROA Customer whose monthly minimum Maximum Demand is less than 1,000 kW must utilize an Aggregator.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

Metering Requirements:

The load under this tariff shall be separately metered by *a Wireless Under Glass Meter or* an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA customer shall be required to pay the System Access Charge, as provided for under the ROA customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses as shown below on the Company's Distribution System associated with the movement of Power and for compensation for losses.

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~0.690~~ *0.705*%
Customer Voltage Level 2	~~1.390~~ *1.271*%	~~2.480~~ *2.366*%
Customer Voltage Level 3	~~3.660~~ *3.221*%	~~7.900~~ *7.643*%

(Continued on Sheet No. E-28.00)

See Brege Testimony, Page 6, Lines 10-17 and Page 7, Lines 3-6; Exhibit A-53 (RLB-1) Items #6 and 13

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

HEATHER A. BREINING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Environmental - Air Quality Compliance
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-54 (HAB-1)

Witness: HABreining
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Description	12 Mos Ended 12/31/2017	12 Mos Ending 12/31/2018	12 Mos Ending 12/31/2019	24 Mos Ending 12/31/2019	12 Mos Ending 12/31/2019
1	J.H. Campbell, Unit 1 - Dry Sorbent Injection	**2,947,323**	**300,000**	**-**	**300,000**	**-**
	Labor	453,411	131,276	-	131,276	-
	Contractor	2,427,243	138,837	-	138,837	-
	Materials	156	-	-	-	-
	Business Expenses	357	-	-	-	-
	Contingency	-	22,833	-	22,833	-
	Other (Loadings, Chargebacks)	66,156	7,053	-	7,053	-
2	J.H. Campbell, Unit 1 - Activated Carbon Injection	**31,585**	**-**	**-**	**-**	**-**
	Labor	19,145	-	-	-	-
	Contractor	9,077	-	-	-	-
	Materials	-	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	3,363	-	-	-	-
3	J.H. Campbell, Unit 1 - Pulse Jet Fabric Filters	**912,535**	**-**	**-**	**-**	**-**
	Labor	121,883	-	-	-	-
	Contractor	758,396	-	-	-	-
	Materials	979	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	31,276	-	-	-	-
4	J.H. Campbell, Unit 2 - Dry Sorbent Injection	**2,085,047**	**300,000**			
	Labor	373,024	131,276			
	Contractor	1,654,725	138,837			
	Materials	-	-			
	Business Expenses	-	-			
	Contingency	-	22,833			
	Other (Loadings, Chargebacks)	57,299	7,053			
5	J.H. Campbell, Unit 2 - Activated Carbon Injection	**68,701**				
	Labor	22,934				
	Contractor	41,743				
	Materials	-				
	Business Expenses	-				
	Contingency	-				
	Other (Loadings, Chargebacks)	4,025				
6	J.H. Campbell, Unit 3 - Pulse Jet Fabric Filters	**2,694,923**				
	Labor	427,449				
	Contractor	2,370,962				
	Materials	62,429				
	Business Expenses	746				
	Contingency	-				
	Other (Loadings, Chargebacks)	(166,663)				
7	J.H. Campbell, Unit 3 - Activated Carbon Injection	**51,810**				
	Labor	32,731				
	Contractor	19,728				
	Materials	-				
	Business Expenses	-				
	Contingency	-				
	Other (Loadings, Chargebacks)	(648)				
8	J.H. Campbell, Unit 3 - Spray Dry Absorber	**2,466,876**	**767,000**			
	Labor	524,872	441,657			
	Contractor	2,190,073	263,564			
	Materials	(176,477)	-			
	Business Expenses	919	1,610			
	Contingency	-	49,930			
	Other (Loadings, Chargebacks)	(72,511)	10,239			
9	**Total Capital**	**11,258,800**	**1,367,000**	**-**	**300,000**	**-**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Environmental - Coal Combustion Residuals Compliance
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-55 (HAB-2)
Page: 1 of 1
Witness: HABreining
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	J.H. Campbell Site - RCRA	**16,251,298**	**2,309,835**	**-**	**2,309,835**	**-**
	Labor	2,138,048	397,997	-	397,997	-
	Contractor	13,073,185	1,292,559	-	1,292,559	-
	Materials	1,089,260	337,272	-	337,272	-
	Business Expenses	19,305	1,022	-	1,022	-
	Contingency	-	220,982	-	220,982	-
	Other (Loadings, Chargebacks)	(68,501)	60,003	-	60,003	-
2	D.E. Karn/J.C. Weadock Site - RCRA	**2,308,313**	**7,474,471**	**-**	**7,474,471**	**-**
	Labor	443,986	869,160	-	869,160	-
	Contractor	1,563,058	5,832,851	-	5,832,851	-
	Materials	231,027	-	-	-	-
	Business Expenses	5,540	-	-	-	-
	Contingency	-	544,973	-	544,973	-
	Other (Loadings, Chargebacks)	64,702	227,487	-	227,487	-
3	J.R. Whiting Site - RCRA	**36,066**	**-**	**-**	**-**	**-**
	Labor	2,459	-	-	-	-
	Contractor	33,159	-	-	-	-
	Materials	-	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	447	-	-	-	-
4	**Total Capital**	18,595,677	9,784,305	-	9,784,305	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Environmental - 316(b) Compliance
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-56 (HAB-3)
Page: 1 of 1
Witness: HABreining
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	J.H. Campbell, Units 1&2 - 316(b)	**35,170**	**130,000**	**-**	**130,000**	**-**
	Labor	2,813	28,637	-	28,637	-
	Contractor	32,000	66,218	-	66,218	-
	Materials	-	14,038	-	14,038	-
	Business Expenses	-	41	-	41	-
	Contingency	-	19,197	-	19,197	-
	Other (Loadings, Chargebacks)	357	1,868	-	1,868	-
2	D.E, Karn, Units 1&2 - 316(b)	**44,730**	**60,000**	**-**	**60,000**	**-**
	Labor	3,897	9,453	-	9,453	-
	Contractor	40,290	34,315	-	34,315	-
	Materials	-	9,157	-	9,157	-
	Business Expenses	-	28	-	28	-
	Contingency	-	6,000	-	6,000	-
	Other (Loadings, Chargebacks)	544	1,046	-	1,046	-
3	**Total Capital**	79,900	190,000	-	190,000	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Environmental - SEEG Compliance
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-57 (HAB-4)
Page: 1 of 1
Witness: HABreining
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	J.H. Campbell Site - SEEG	**180,101**	**72,291**	**-**	**72,291**	**-**
	Labor	48,550	14,083	-	14,083	-
	Contractor	133,275	56,400	-	56,400	-
	Materials	6,506	(6,461)	-	(6,461)	-
	Business Expenses	-	-	-	-	-
	Contingency	-	7,475	-	7,475	-
	Other (Loadings, Chargebacks)	(8,229)	794	-	794	-
2	D.E, Karn Site - SEEG	**1,062,865**	**599,895**	**-**	**599,895**	**-**
	Labor	205,746	94,518	-	94,518	-
	Contractor	812,411	343,090	-	343,090	-
	Materials	9,444	91,558	-	91,558	-
	Business Expenses	1,079	277	-	277	-
	Contingency	-	59,990	-	59,990	-
	Other (Loadings, Chargebacks)	34,185	10,462	-	10,462	-
3	**Total Capital**	1,242,966	672,186	-	672,186	-

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
____	)	

EXHIBITS

OF

EUGENE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Service Area Sales by Major Customer Classes and System Output
5-Year Historical
(GWh)

Case No.: U-20134
Exhibit No.: A-5 (EMB-1)
Schedule: E-1

Witness: EMBreuring
Date: May 2018

Total Company Electric Deliveries

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
								Losses & Company Use		
Line No.	**Year**		**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**GWh**	**% of Output**	**System Output**
1	2013	Hist	12,793	11,965	11,585	551	36,894	3,223	8.0%	40,117
2	2014	Hist	12,594	11,858	12,583	561	37,596	3,316	8.1%	40,912
3	2015	Hist	12,495	12,696	11,546	544	37,281	2,892	7.2%	40,173
4	2016	Hist	12,789	12,868	11,709	545	37,911	3,020	7.4%	40,931
5	2017	Hist	12,341	12,749	11,759	544	37,394	2,639	6.6%	40,032

Bundled Electric Deliveries

								Losses & Company Use		
	Year		**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**GWh**	**% of Output**	**System Output**
6	2013	Hist	12,793	10,908	8,646	551	32,897	3,175	8.8%	36,073
7	2014	Hist	12,594	10,848	9,614	561	33,617	3,214	8.7%	36,831
8	2015	Hist	12,495	11,699	8,605	544	33,343	2,771	7.7%	36,114
9	2016	Hist	12,789	11,843	8,839	545	34,017	2,964	8.0%	36,980
10	2017	Hist	12,341	11,763	8,966	544	33,614	2,522	7.0%	36,136

Choice Electric Deliveries

								Losses & Company Use		
	Year		**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**GWh**	**% of Output**	**System Output**
11	2013	Hist	-	1,058	2,939	-	3,996	47	1.2%	4,044
12	2014	Hist	-	1,011	2,969	-	3,979	102	2.5%	4,081
13	2015	Hist	-	998	2,940	-	3,938	121	3.0%	4,059
14	2016	Hist	-	1,024	2,870	-	3,895	56	1.4%	3,951
15	2017	Hist	-	986	2,794	-	3,780	116	3.0%	3,896

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Service Area Sales by Major Customer Classes and System Output
5-Year Projected
(GWh)

Case No.: U-20134
Exhibit No.: A-15 (EMB-2)
Schedule: E-1
Page: 1 of 1
Witness: EMBreuring
Date: May 2018

Total Company Electric Deliveries

Line No.	Year		(a) Residential	(b) Commercial	(c) Industrial	(d) Other	(e) Total	(f) Losses & Company Use GWh	(g) Losses & Company Use % of Output	(h) System Output
1	2018	Fcst	12,335	12,784	11,973	541	37,632	2,771	6.9%	40,403
2	2019	Fcst	12,197	12,595	12,143	543	37,477	2,761	6.9%	40,238
3	2020	Fcst	12,108	12,503	12,379	544	37,534	2,768	6.9%	40,302
4	2021	Fcst	12,146	12,364	12,416	546	37,471	2,763	6.9%	40,234
5	2022	Fcst	12,184	12,294	12,605	547	37,630	2,774	6.9%	40,404

Bundled Electric Deliveries

Line No.	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
6	2018	Fcst	12,335	11,765	9,129	541	33,770	2,460	6.8%	36,230
7	2019	Fcst	12,197	11,590	9,289	543	33,619	2,450	6.8%	36,070
8	2020	Fcst	12,108	11,508	9,453	544	33,612	2,452	6.8%	36,064
9	2021	Fcst	12,146	11,378	9,469	546	33,539	2,446	6.8%	35,985
10	2022	Fcst	12,184	11,313	9,594	547	33,638	2,452	6.8%	36,090

Choice Electric Deliveries

Line No.	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
11	2018	Fcst	-	1,019	2,843	-	3,862	311	7.5%	4,173
12	2019	Fcst	-	1,005	2,853	-	3,858	311	7.4%	4,169
13	2020	Fcst	-	995	2,927	-	3,922	316	7.5%	4,237
14	2021	Fcst	-	986	2,947	-	3,933	317	7.4%	4,249
15	2022	Fcst	-	981	3,011	-	3,992	321	7.4%	4,314

Schedule E-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year Total Company Electric Revenues & Deliveries
January 2019 - December 2019

Case No.: U-20134
Exhibit No.: A-15 (EMB-3)
Schedule: E-2
Page: 1 of 1
Witness: EMBreuring
Date: May 2018

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Less Non-Base Tariff Items						**Test Year**		**Test Year**	
Line No.	**Description**	**2017 Actual**	**PSCR Factor**	**Surcharges**	**Other Adjustments**	**Weather Normalization**	**Change In Determinants**	**U-17990 Pro Forma**	**PSCR Factor**	**Total Company**	**Non-Jurisdictional**	**Jurisdictional**
	Adjusted Operating Revenues ($000)											
	Cycle Billed Tariff Revenue											
1	Base Tariff	$ 2,156,797	$ -	$ -	$ -	$ 11,737	$ 18,347	$ (7,695)	$ -	$ 2,179,187	$ 11,126	$ 2,168,061
2	GSG Power Supply	2,589	(2,589)	-	-	-	-	-	1,548	1,548	-	1,548
3	Base PSCR	1,824,116	-	-	-	10,859	15,485	158,354	-	2,008,813	13,612	1,995,201
4	PSCR Factor	78,611	(78,611)	-	-	-	-	-	26,601	26,601	17	26,584
5	Total Cycle Billed Tariff Revenue	4,062,113	(81,200)	-	-	22,596	33,832	150,659	28,149	4,216,149	24,755	4,191,394
	Cycle Billed Surcharge Revenue											
6	Energy Optimization	80,056	-	(80,056)	-	-	-	-	-	-	-	-
7	PEM & OEM	-	-	-	-	-	-	-	-	-	-	-
8	Renewable Energy	1,365	-	(1,365)	-	-	-	-	-	-	-	-
9	Security Recovery Factor	-	-	-	-	-	-	-	-	-	-	-
10	Major Maintenance	0	-	(0)	-	-	-	-	-	-		
11	Low-Income Assistance Fund	20,612	-	(20,612)	-	-	-	-	-	-	-	-
12	Stranded Cost Recovery	-	-	-	-	-	-	-	-	-	-	-
13	Securitization (Classic7)	35,155	-	(35,155)	-	-	-	-	-	-		
14	Securitization	-	-	-	-	-	-	-	-	-	-	-
15	Securitization Tax	-	-	-	-	-	-	-	-	-	-	-
16	Regulatory Asset Recovery 10d(4)	-	-	-	-	-	-	-	-	-	-	-
17	ERIP	-	-	-	-	-	-	-	-	-	-	-
18	Other Provisions for Refund	(28,617)	-	28,617	-	-	-	-	-	-	-	-
19	Total Cycle Billed Surcharge Revenue	108,571	-	(108,571)	-	-	-	-	-	-	-	-
	Unbilled Revenue											
20	Base Tariff	36,931	-	-	(36,931)	-	-	-	-	-	-	-
21	Base PSCR	28,716	-	-	(28,716)	-	-	-	-	-	-	-
22	PSCR Factor	(1,247)	1,247	-	-	-	-	-	-	-	-	-
23	Total Unbilled Revenue	64,400	1,247	-	(65,647)	-	-	-	-	-	-	-
24	PSCR Over/Under Recovery	(14,831)	14,831	-	-	-	-	-	-	-	-	-
25	Total Calendar Revenue	4,220,253	(65,122)	(108,571)	(65,647)	22,596	33,832	150,659	28,149	4,216,149	24,755	4,191,394
26	Miscellaneous Revenue	96,147	(958)	-	(57,157)	-	-	-	-	38,032	-	38,032
27	Intersystem Sales Revenue	95,687	-	-	(95,687)	-	-	-	-	80,222	736	79,486
28	Total Operating Revenue	$ 4,412,087	$ (66,080)	$ (108,571)	$ (218,491)	$ 22,596	$ 33,832	$ 150,659	$ 28,149	$ 4,334,403	$ 25,491	$ 4,308,912
	Revenue Adjustments											
29	Jobwork Revenue	14,201	-	-	-	-	-	-	-	14,201	-	14,201
30	Jobwork Expense	(11,293)	-	-	-	-	-	-	-	(11,293)	-	(11,293)
31	Total Revenue Adjustments	2,908	-	-	-	-	-	-	-	2,908	-	2,908
32	Adjusted Total Operating Revenue	$ 4,414,995	$ (66,080)	$ (108,571)	$ (218,491)	$ 22,596	$ 33,832	$ 150,659	$ 28,149	$ 4,337,311	$ 25,491	$ 4,311,819
	Electric Deliveries (MWh)											
33	Cycle Billed Bundled Service	33,132,637	-	-	-	197,232	281,263	-	-	33,611,132	381,686	33,229,446
34	Cycle Billed Self-generation	44,701	-	-	-	-	(16,087)	-	-	28,614	-	28,614
35	Cycle Billed Electric Choice	3,798,711	-	-	-	3,994	49,366	-	-	3,852,071	-	3,852,071
36	Intersystem Sales	1,677,543	-	-	(1,677,543)	-	-	-	-	-	-	-
37	Unbilled Bundled Service	436,541	-	-	(436,541)	-	-	-	-	-	-	-
38	Unbilled Electric Choice	(18,998)	-	-	18,998	-	-	-	-	-	-	-
39	Total Electric Deliveries	39,071,135	-	-	(2,095,086)	201,226	314,542	-	-	37,491,817	381,686	37,110,131

Schedule E-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Deliveries & Customer Counts by Rate Category
(Annual Deliveries in MWh)

Case No.: U-20134
Exhibit No.: A-15 (EMB-4)
Schedule: E-3
Page: 1 of 1
Witness: EMBreuring
Date: May 2018

Line No.	Description	(a) 2017 Actual Avg. No. of Customers	(b) 2017 Actual Annual Deliveries	(c) Test Year Total Company Avg. No. of Customers	(d) Test Year Total Company Annual Deliveries	(e) Test Year Jurisdictional No. of Customers	(f) Test Year Jurisdictional Annual Deliveries
	Bundled Residential Service						
1	Standard Service RS	1,574,612	11,971,459	1,502,920	11,387,714	1,502,920	11,387,714
2	Peak Pwr Savers / Dynamic Pricing	16,542	134,860	98,407	770,034	98,407	770,034
3	Time-of-Day RT	2,285	56,947	2,246	58,404	2,246	58,404
4	Electric Vehicles REV-1	796	9,911	815	9,980	815	9,980
5	Electric Vehicles REV-2	35	68	36	68	36	68
6	Total Bundled Residential	1,594,270	12,173,245	1,604,424	12,226,199	1,604,424	12,226,199
	Bundled Secondary Service						
7	Secondary Energy-only GS	192,787	3,780,656	194,069	3,810,874	194,069	3,810,874
8	Secondary Demand GSD	20,407	3,533,708	20,541	3,578,957	20,541	3,578,957
9	Total Bundled Secondary	213,194	7,314,364	214,610	7,389,831	214,610	7,389,831
	Bundled Primary Service						
10	Primary Energy-only GP	1,786	1,295,232	1,729	1,401,001	1,729	1,401,001
11	Primary Demand GPD	1,653	10,440,526	1,702	10,938,598	1,702	10,938,598
12	Primary Time-of-Use GPTU	236	903,086	294	664,177	294	664,177
13	General Service Primary (EIP)	18	398,040	19	383,083	19	383,083
14	Economic Development E-1	-	-	-	-	-	-
15	Total Bundled Primary	3,693	13,036,884	3,744	13,386,860	3,744	13,386,860
	Bundled Street Lighting Service						
16	Unmetered Lighting GUL	4,412	118,285	4,106	120,667	4,106	120,667
17	Metered Lighting GML	365	6,800	272	14,989	272	14,989
18	Unmetered GU	481	97,169	466	90,900	466	90,900
19	Total Bundled Street Lighting	5,258	222,254	4,844	226,556	4,844	226,556
	Bundled Self-generation Service						
20	Self-generation GSG-1	10	10,294	23	10,494	23	10,494
21	Self-generation GSG-2	12	34,407	10	18,120	10	18,120
22	Total Bundled Self-generation	22	44,701	33	28,614	33	28,614
	Bundled Other Service						
23	Wholesale	1	364,894	1	360,091	-	-
24	Grand Rapids	1	20,996	1	21,595	-	-
25	Total Bundled Other	2	385,890	2	381,686	-	-
20	Cycle Billed Bundled Service	1,816,439	33,177,338	1,827,657	33,639,746	1,827,655	33,258,060
26	Unbilled		436,541	-	-	-	-
27	Calendar Bundled Service	1,816,439	33,613,879	1,827,657	33,639,746	1,827,655	33,258,060
	ROA Secondary Service						
28	Secondary Energy-only GS	106	21,656	111	21,921	111	21,921
29	Secondary Demand GSD	496	198,907	513	203,294	513	203,294
30	Total ROA Secondary	602	220,563	624	225,215	624	225,215
	ROA Primary Service						
31	Primary Energy-only GP	46	70,419	49	70,590	49	70,590
32	Primary Demand GPD	361	3,507,729	389	3,556,266	389	3,556,266
33	Total ROA Primary	407	3,578,148	438	3,626,855	438	3,626,855
34	Cycle Billed ROA Service	1,009	3,798,711	1,062	3,852,071	1,062	3,852,071
35	Unbilled ROA		(18,998)	-	-	-	-
36	Calendar ROA Service	1,009	3,779,713	1,062	3,852,071	1,062	3,852,071
37	**Cycle Billed Total Deliveries**	1,817,448	36,976,049	1,828,719	37,491,817	1,828,717	37,110,131
38	**Unbilled**	-	417,543	-	-	-	-
39	**Calendar Total Deliveries**	1,817,448	37,393,592	1,828,719	37,491,817	1,828,717	37,110,131

Schedule E-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Annual System Load Factor
2013 - 2017 Historical / 2018 - 2022 Forecast

Case No.: U-20134
Exhibit No.: A-15 (EMB-5)
Schedule: E-4
Page: 1 of 1
Witness: EMBreuring
Date: May 2018

			(a)	(b)	(c)
Line No.	**Year**		**System Output GWh**	**System Peak Demand MW**	**Annual Load Factor**
1	2013	Hist	40,117	8,509	53.8%
2	2014	Hist	40,912	7,498	62.3%
3	2015	Hist	40,173	7,812	58.7%
4	2016	Hist	40,931	8,227	56.6%
5	2017	Hist	40,032	7,634	59.9%
6	2018	Fcst	40,403	8,074	57.1%
7	2019	Fcst	40,238	8,018	57.3%
8	2020	Fcst	40,302	7,940	57.8%
9	2021	Fcst	40,234	7,876	58.3%
10	2022	Fcst	40,404	7,861	58.7%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Estimated Electric Rate Case PSCR Factor
January 2019 - December 2019

Case No.: U-20134
Exhibit No.: A-58 (EMB-6)
Page: 1 of 1
Witness: EMBreuring
Date: May 2018

Line No.	Description		(a) Total Company	(b) Jurisdictional Factors	(c) Jurisdictional	(d) Non-Jurisdictional Factors	(e) Non-Jurisdictional
	Expenses ($000)						
1	System Power Supply Costs	(1)	$ 1,684,726	98.99%	$ 1,667,675	1.01%	$ 17,051
2	Transmission & Market Administrative Expense	(2)	439,642	99.03%	435,377	0.97%	4,265
3	PSCR Expenses		$ 2,124,368		$ 2,103,052		$ 21,316
	PSCR Revenue Contributions ($000)						
4	Intersystem Sales Revenue	(3)	$ 80,222	99.08%	$ 79,486	0.92%	$ 736
5	Self-Generation	(4)	1,548	100.00%	1,548	0.00%	-
6	Base Jurisdictional PSCR x $0.06011		1,995,201	100.00%	1,995,201	0.00%	-
7	Base Non-Jurisdictional PSCR x $0.06011		1,297	0.00%	-	100.00%	1,297
8	Wholesale Fuel Revenue	(5)	12,315	0.00%	-	100.00%	12,315
9	PSCR Revenue Contributions		$ 2,090,583		$ 2,076,235		$ 14,348
10	PSCR (Over)/Under Recovery		$ 33,785		$ 26,817		$ 6,968
	Electric Deliveries (MWh)						
11	Jurisdictional Bundled Deliveries	(6)			33,258,060		
12	Less: Self-Generation	(7)			(28,614)		
13	Less: Economic Development E-1				-		
14	Total Bundled PSCR Deliveries				33,229,446		
	Estimated Jurisdictional PSCR Factor						
15	PSCR (Over)/Under Recovery ($000)				$ 26,817		
16	Total Bundled PSCR Deliveries (MWh)				33,229,446		
17	Total Jurisdictional PSCR Factor ($ per kWh)				**$ 0.00080**		
	Estimated PSCR Recovery						
18	PSCR Revenue Contributions		$ 2,090,583		$ 2,076,235		$ 14,348
19	Plus: PSCR (Over)/Under Recovery		26,584		26,584		-
20	Non-jurisdictional PSCR Factor Contribution		17		-		17
21	Total PSCR Revenues		$ 2,117,184		$ 2,102,819		$ 14,365
22	Total PSCR (Over)/Under Recovery		$ 7,184		$ 233		$ 6,951

Total Losses	0.0735
Less: Transmission	0.0000
System Losses	0.0735
System Efficiency	1.0793
PSCR Base @ Gen	0.05563
System Efficiency	1.0793
PSCR Base @ Del	**0.06004**

Notes:
(1) Exhibit A-33 (RTB-1), page 1, line 40; plus page 3, line 57; less page 1, line 34.
(2) Exhibit A-33 (RTB-1), page 1, line 34.
(3) Exhibit A-33 (RTB-1), page 3, line 57.
(4) Exhibit A-15 (EMB-3), Schedule E-2, line 2, column (h).
(5) $0.0342/kWh from U-18401, Exhibit A-1, Schedule 4, page 1 (Supplemental Power: Energy Charge rate).
(6) Exhibit A-15 (EMB-4), Schedule E-3, line 27, column (f).
(7) Exhibit A-15 (EMB-4), Schedule E-3, line 22, column (f).

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief. ______________________________________	))))))	Case No. U-20134

EXHIBITS

OF

JOHN P. BROSCHAK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

JANUARY 1, 2019 THROUGH DECEMBER 31, 2019
MAJOR OUTAGES, FOSSIL GENERATION AND LUDINGTON

Line No.	(a) **Unit**	(b) **Days**	(c) **Start Date**	(d) **Stop Date**
1	Ludington 1	59	01/01/19	03/01/19
2	Karn 4	147	01/01/19	05/28/19
3	Ludington 3	334	02/01/19	12/31/19
4	Campbell 1	60	03/06/19	05/05/19
5	Karn 1	60	03/14/19	05/13/19
6	Ludington 4	62	09/03/19	11/04/19
7	Karn 3	69	09/04/19	11/12/19
8	Karn 2	60	09/05/19	11/04/19
9	Campbell 2	60	09/12/19	11/11/19
10	Karn 4	69	09/12/19	11/20/19
11	Campbell 3	55	10/05/19	11/29/19

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generating Unit Availability Projections
January 1, 2019 Through December 31, 2019

Case No.: U-20134
Exhibit No.: A-60 (JPB-2)
Page: 1 of 1
Witness: JPBroschak
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Plant**	**Availability**	**Periodic Factor**	**ROR**	**Actual ROR 2013-2017**	**Actual NEV 2014-2017**
1	Campbell 1	74.78%	16.44%	10.50%	12.19%	$43,080,843
2	Campbell 2	73.07%	21.01%	7.50%	12.35%	$48,100,625
3	Campbell 3	95.00%	0.00%	5.00%	9.14%	$180,315,525
6	Karn 1	71.45%	16.44%	14.50%	24.30%	$34,814,413
7	Karn 2	77.28%	16.45%	7.50%	12.84%	$37,622,391
8	Karn 3	68.07%	18.96%	16.00%	25.16%	-$4,716,825
9	Karn 4	31.76%	59.28%	22.00%	25.56%	-$9,183,010
15	Ludington 1	95.96%	1.08%	3.00%	8.07%	$24,703,527
16	Ludington 2	95.96%	1.08%	3.00%	7.90%	$15,434,973
17	Ludington 3	0.00%	100.00%	3.00%	9.45%	$20,278,682
18	Ludington 4	95.96%	1.08%	3.00%	2.74%	$12,601,411
19	Ludington 5	95.96%	1.08%	3.00%	28.11%	$11,759,569
20	Ludington 6	95.96%	1.08%	3.00%	5.57%	$18,438,081
21	CTs[1]	85.00%	0.00%	15.00%	5.55%	$1,724,864
22	Hydros	92.21%	2.94%	5.00%	6.55%	$37,509,835
23	Zeeland CC	90.00%	6.25%	4.00%	4.01%	$77,601,824
24	Zeeland 1A	93.74%	2.36%	4.00%	2.68%	$4,629,555
25	Zeeland 1B	93.75%	2.35%	4.00%	3.50%	$4,414,820
26	Jackson[2]	92.78%	2.85%	4.50%	3.51%	$23,410,734

[1] Does not include Zeeland.
[2] Jackson acquired in December 2015.

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures
For the years 2017 through 2019
($000)

Case No.: U-20134
Exhibit No.: A-12 (JPB-3)
Schedule: B-5.1
Page: 1 of 4
Witness: JPBroschak
Date: May 2018

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	Steam Power Generation					
2	Environmental	$ 45,706	$ 38,625	$ 23,062	$ 61,687	$ 23,062
3	Routine and Small CapEx	$ 58,782	$ 69,667	$ 77,911	$ 147,579	$ 77,911
4	Total Steam Production	$ 104,488	$ 108,292	$ 100,974	$ 209,266	$ 100,974
5	Hydraulic Power Generation					
6	Routine and Small CapEx	$ 15,225	$ 14,790	$ 21,281	$ 36,071	$ 21,281
7	Total hydraulic production	$ 15,225	$ 14,790	$ 21,281	$ 36,071	$ 21,281
8	Pumped Storage Generation					
9	Ludington Overhaul	$ 47,198	$ 34,198	$ 32,658	$ 66,856	$ 32,658
10	Routine and Small CapEx	$ 9,213	$ 8,048	$ 11,526	$ 19,574	$ 11,526
11	Total Pumped Storage Generation	$ 56,411	$ 42,246	$ 44,184	$ 86,430	$ 44,184
12	Other Production Plant					
13	Routine and Small CapEx	$ 1,612	$ 7,269	$ 2,295	$ 9,564	$ 2,295
14	Total Other Production Plant	$ 1,612	$ 7,269	$ 2,295	$ 9,564	$ 2,295
15	Grand Total	$ 177,736	$ 172,597	$ 168,734	$ 341,331	$ 168,734

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures
For the years 2017 through 2019
($000's)

Case No.: U-20134
Exhibit No.: A-12 (JPB-3)
Schedule: B-5.1
Page: 2 of 4
Witness: JPBroschak
Date: May 2018

Generations Capital Expenditures

Line No.	(a) Description	(b) Historical 12 Mos Ended 12/31/2017	(c)	(d) Projected Bridge Year 12 Mos Ending 12/31/2018	(e)	(f) Capital Expenditures Projected Test Year 12 Mos Ending 12/31/2019	(g)	(h) 24 Mos Ending 12/31/2019	(i)	(j) Projected Test Year 12 Mos Ending 12/31/2019	(k)
1	JHCampbell 1&2	$ 7,856		$ 5,521		$ 11,288		$ 16,809		$ 11,288	
	Contractor		$ 2,359		$ 2,241		$ 6,456		$ 8,697		$ 6,456
	Labor		$ 1,724		$ 1,103		$ 1,778		$ 2,882		$ 1,778
	Materials		$ 3,502		$ 1,431		$ 1,723		$ 3,154		$ 1,723
	Business Expenses		$ 16		$ 2		$ 5		$ 7		$ 5
	Contingency		$ -		$ 632		$ 1,129		$ 1,761		$ 1,129
	Other (Loadings, Chargebacks)		$ 255		$ 111		$ 197		$ 308		$ 197
2	JHCampbell 3	$ 2,570		$ 10,695		$ 16,278		$ 26,973		$ 16,278	
	Contractor		$ 665		$ 5,244		$ 9,310		$ 14,554		$ 9,310
	Labor		$ 744		$ 2,360		$ 2,565		$ 4,925		$ 2,565
	Materials		$ 1,104		$ 1,931		$ 2,484		$ 4,415		$ 2,484
	Business Expenses		$ 4		$ 8		$ 8		$ 15		$ 8
	Contingency		$ -		$ 1,548		$ 1,628		$ 3,175		$ 1,628
	Other (Loadings, Chargebacks)		$ 52		$ (395)		$ 284		$ (111)		$ 284
3	DEKarn 1&2	$ 11,816		$ 5,895		$ 5,730		$ 11,625		$ 5,730	
	Contractor		$ 4,238		$ 3,252		$ 3,277		$ 6,529		$ 3,277
	Labor		$ 2,856		$ 1,122		$ 903		$ 2,025		$ 903
	Materials		$ 4,266		$ 889		$ 875		$ 1,763		$ 875
	Business Expenses		$ 4		$ 2		$ 3		$ 5		$ 3
	Contingency		$ -		$ 516		$ 573		$ 1,089		$ 573
	Other (Loadings, Chargebacks)		$ 453		$ 115		$ 100		$ 215		$ 100
4	DEKarn 3&4	$ 16,566		$ 8,957		$ 10,800		$ 19,757		$ 10,800	
	Contractor		$ 11,145		$ 3,886		$ 6,177		$ 10,063		$ 6,177
	Labor		$ 2,319		$ 1,396		$ 1,702		$ 3,097		$ 1,702
	Materials		$ 2,420		$ 3,057		$ 1,648		$ 4,706		$ 1,648
	Business Expenses		$ 5		$ 2		$ 5		$ 7		$ 5
	Contingency		$ -		$ 423		$ 1,080		$ 1,503		$ 1,080
	Other (Loadings, Chargebacks)		$ 678		$ 193		$ 188		$ 381		$ 188
5	Zeeland	$ 6,923		$ 19,908		$ 14,408		$ 34,316		$ 14,408	
	Contractor		$ 5,472		$ 11,284		$ 7,470		$ 18,753		$ 7,470
	Labor		$ 337		$ 1,492		$ 1,028		$ 2,520		$ 1,028
	Materials		$ 890		$ 5,096		$ 4,305		$ 9,401		$ 4,305
	Business Expenses		$ 1		$ 6		$ 1		$ 8		$ 1
	Contingency		$ -		$ 1,798		$ 1,441		$ 3,239		$ 1,441
	Other (Loadings, Chargebacks)		$ 223		$ 232		$ 163		$ 395		$ 163
6	Jackson Generating Station	$ 12,845		$ 18,691		$ 19,408		$ 38,099		$ 19,408	
	Contractor		$ 5,915		$ 9,690		$ 10,062		$ 19,752		$ 10,062
	Labor		$ 1,231		$ 1,334		$ 1,385		$ 2,719		$ 1,385
	Materials		$ 5,673		$ 5,585		$ 5,799		$ 11,384		$ 5,799
	Business Expenses		$ 1		$ 2		$ 2		$ 3		$ 2
	Contingency		$ -		$ 1,869		$ 1,941		$ 3,810		$ 1,941
	Other (Loadings, Chargebacks)		$ 25		$ 211		$ 219		$ 431		$ 219
7	CTs	$ 207		$ -		$ -		$ -		$ -	
	Contractor		$ 148		$ -		$ -				$ -
	Labor		$ 64		$ -		$ -				$ -
	Materials		$ (2)		$ -		$ -				$ -
	Business Expenses		$ (1)		$ -		$ -				$ -
	Contingency		$ -		$ -		$ -				$ -
	Other (Loadings, Chargebacks)		$ (2)		$ -		$ -				$ -
8	Classic 7	$ (1)		$ -		$ -		$ -		$ -	
	Contractor		$ -		$ -		$ -				$ -
	Labor		$ -		$ -		$ -				$ -
	Materials		$ -		$ -		$ -				$ -
	Business Expenses		$ -		$ -		$ -				$ -
	Contingency		$ -		$ -		$ -				$ -
	Other (Loadings, Chargebacks)		$ (1)		$ -		$ -				$ -
9	Hydros	$ 15,225		$ 14,790		$ 21,281		$ 36,071		$ 21,281	
	Contractor		$ 8,741		$ 8,937		$ 11,492		$ 20,429		$ 11,492
	Labor		$ 3,914		$ 2,871		$ 4,682		$ 7,553		$ 4,682
	Materials		$ 1,329		$ 1,225		$ 1,703		$ 2,928		$ 1,703
	Business Expenses		$ 193		$ 36		$ 213		$ 249		$ 213
	Contingency		$ -		$ 1,301		$ 2,128		$ 3,429		$ 2,128
	Other (Loadings, Chargebacks)		$ 1,049		$ 419		$ 1,064		$ 1,483		$ 1,064
10	Ludington	$ 56,411		$ 42,246		$ 44,184		$ 86,430		$ 44,184	
	Contractor		$ 82,105		$ 27,857		$ 30,939		$ 58,796		$ 30,939
	Labor		$ 12,970		$ 8,110		$ 9,916		$ 18,027		$ 9,916
	Materials		$ 3,407		$ 1,388		$ 3,113		$ 4,502		$ 3,113
	Business Expenses		$ 355		$ 20		$ 115		$ 136		$ 115
	Contingency		$ -		$ 1,359		$ 6,002		$ 7,360		$ 6,002
	Other (Loadings, Chargebacks)		$ (42,425)		$ 3,512		$ (5,902)		$ (2,390)		$ (5,902)
11	Admin and Other	$ 1,612		$ 7,269		$ 2,295		$ 9,564		$ 2,295	
	Contractor		$ 688		$ 3,696		$ 915		$ 4,611		$ 915
	Labor		$ 69		$ 1,018		$ 252		$ 1,270		$ 252
	Materials		$ 844		$ 1,792		$ 939		$ 2,732		$ 939
	Business Expenses		$ -		$ 3		$ 1		$ 4		$ 1
	Contingency		$ -		$ 646		$ 160		$ 806		$ 160
	Other (Loadings, Chargebacks)		$ 10		$ 113		$ 28		$ 141		$ 28
12	Air Quality	$ 11,259		$ 1,367		$ -		$ 1,367		$ -	
	Contractor		$ 9,472		$ 541		$ -		$ 541		$ -
	Labor		$ 1,975		$ 704		$ -		$ 704		$ -
	Materials		$ (113)		$ -		$ -		$ -		$ -
	Business Expenses		$ 2		$ 2		$ -		$ 2		$ -
	Contingency		$ -		$ 96		$ -		$ 96		$ -
	Other (Loadings, Chargebacks)		$ (78)		$ 24		$ -		$ 24		$ -
13	RCRA	$ 18,722		$ 9,784		$ -		$ 9,784		$ -	
	Contractor		$ 14,772		$ 7,125		$ -		$ 7,125		$ -
	Labor		$ 2,604		$ 1,267		$ -		$ 1,267		$ -
	Materials		$ 1,320		$ 337		$ -		$ 337		$ -
	Business Expenses		$ 25		$ 1		$ -		$ 1		$ -
	Contingency		$ -		$ 766		$ -		$ 766		$ -
	Other (Loadings, Chargebacks)		$ 0		$ 287		$ -		$ 287		$ -
14	316b	$ 80		$ 190		$ -		$ 190		$ -	
	Contractor		$ 72		$ 101		$ -		$ 101		$ -
	Labor		$ 7		$ 38		$ -		$ 38		$ -
	Materials		$ -		$ 23		$ -		$ 23		$ -
	Business Expenses		$ -		$ 0		$ -		$ 0		$ -
	Contingency		$ -		$ 25		$ -		$ 25		$ -
	Other (Loadings, Chargebacks)		$ 1		$ 3		$ -		$ 3		$ -
15	SEEG	$ 1,243		$ 672		$ -		$ 672		$ -	
	Contractor		$ 946		$ 399		$ -		$ 399		$ -
	Labor		$ 254		$ 109		$ -		$ 109		$ -
	Materials		$ 16		$ 85		$ -		$ 85		$ -
	Business Expenses		$ 1		$ 0		$ -		$ 0		$ -
	Contingency		$ -		$ 67		$ -		$ 67		$ -
	Other (Loadings, Chargebacks)		$ 26		$ 11		$ -		$ 11		$ -
16	All Other Environmental	$ 14,402		$ 26,612		$ 23,062		$ 49,674		$ 23,062	
	Contractor		$ 10,136		$ 16,695		$ 13,237		$ 29,931		$ 13,237
	Labor		$ 2,369		$ 5,061		$ 3,616		$ 8,677		$ 3,616
	Materials		$ 1,661		$ 1,933		$ 3,503		$ 5,436		$ 3,503
	Business Expenses		$ (0)		$ 1		$ 11		$ 12		$ 11
	Contingency		$ -		$ 2,402		$ 2,295		$ 4,698		$ 2,295
	Other (Loadings, Chargebacks)		$ 238		$ 520		$ 401		$ 921		$ 401
17	**Total Capital**	$ 177,736	$ 177,736	$ 172,597	$ 172,597	$ 168,734	$ 168,734	$ 341,331	$ 341,331	$ 168,734	$ 168,734

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION	Case No.: U-20134
Consumers Energy Company	Exhibit No.: A-12 (JPB-3)
Summary of Projected Electric Capital Expenditures	Schedule: B-5.1
For the years 2017 through 2019	Page: 3 of 4
($000's)	Witness: JPBroschak
	Date: May 2018

Generations Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
				Capital Expenditures		
		Historical	**Projected Bridge Year**	**Projected Test Year**		**Projected Test Year**
Line		**12 Mos Ended**	**12 Mos Ending**	**12 Mos Ending**	**24 Mos Ending**	**12 Mos Ending**
No.	**Description**	**12/31/2017**	**12/31/2018**	**12/31/2019**	**12/31/2019**	**12/31/2019**
1	Contractor	$ 156,873	$ 100,948	$ 99,334	$ 200,282	$ 99,334
2	Labor	$ 33,437	$ 27,985	$ 27,827	$ 55,813	$ 27,827
3	Materials	$ 26,316	$ 24,773	$ 26,092	$ 50,865	$ 26,092
4	Business Expenses	$ 606	$ 85	$ 363	$ 448	$ 363
5	Contingency	$ -	$ 13,448	$ 18,376	$ 31,824	$ 18,376
6	Other (Loadings, Chargebacks)	$ (39,496)	$ 5,357	$ (3,258)	$ 2,100	$ (3,258)
		$ 177,736	$ 172,597	$ 168,734	$ 341,331	$ 168,734

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures
For the year 2019
($000's)

Case No.: U-20134
Exhibit No.: A-12 (JPB-3)
Schedule: B-5.1
Page: 4 of 4
Witness: JPBroschak
Date: May 2018

Generations Capital Expenditures

	(a)	(b)	(c)	(e)
		Capital Expenditures		
		Projected Test Year		
Line		**12 Mos Ending**		
No.	**Description**	**12/31/2019**		**Reference**
1	Campbell 1&2 Non-Environmental	$ 11,288		A-12 (JPB-3), Schedule B-5.1, page 2, line 1, column (j)
2	Campbell 1&2 "All Other Environmental"		$ 11,105	
3	Campbell 3 Non-Environmental	$ 16,278		A-12 (JPB-3), Schedule B-5.1, page 2, line 2, column (j)
4	Campbell 3 "All Other Environmental"		$ 10,284	
5	Karn 1&2 Non-Environmental	$ 5,730		A-12 (JPB-3), Schedule B-5.1, page 2, line 3, column (j)
6	Karn 1&2 "All Other Environmental"		$ 1,674	
7	**Total Other Environmental**		$ 23,062	A-12 (JPB-3), Schedule B-5.1, page 2, line 16, column (j)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures
For the years 2017 through 2019

Case No.: U-20134
Exhibit No.: A-61 (JPB-4)

Witness: JPBroschak
Date: May 2018

Generation Capital Expenditures
AVOIDABLE UNDER AN EARLY RETIREMENT SCENARIO 2023
($000's)

Line No.	Description		2018 Projected		2019 Projected
Campbell 1 retirement scenario					
1	JHCampbell 1				
2	Unavoidable	$	11,143	$	6,273
3	Avoidable	$	-	$	403
4	Incremental	$	1,516	$	11,352
Campbell 2 retirement scenario					
5	JHCampbell 2				
6	Unavoidable	$	14,549	$	15,467
7	Avoidable	$	50	$	250
8	Incremental	$	5,603	$	13,098
Campbell 1 and 2 retirement scenario					
9	JHCampbell 1				
10	Unavoidable	$	11,143	$	6,273
11	Avoidable	$	-	$	403
12	Incremental	$	1,516	$	11,352
13	JHCampbell 2				
14	Unavoidable	$	14,549	$	15,467
15	Avoidable	$	50	$	250
16	Incremental	$	5,603	$	13,098
Karn 1 and 2 retirement scenario					
17	DEKarn 1&2				
18	Unavoidable	$	15,525	$	4,685
19	Avoidable	$	-	$	2,719
20	Incremental	$	-	$	275
21	DEKarn 3&4				
22	Unavoidable	$	8,957	$	10,800
23	Avoidable				
24	Incremental	$	8,000	$	7,000

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures
For the years 2017 through 2019

Case No.: U-20134
Exhibit No.: A-61 (JPB-4)

Witness: JPBroschak
Date: May 2018

Generations Capital Expenditures
AVOIDABLE UNDER AN EARLY RETIREMENT SCENARIO 2021
($000's)

Line No.		Description		2018 Projected		2019 Projected
Campbell 1 retirement scenario						
1	JHCampbell 1					
2		Unavoidable	$	10,549	$	2,970
3		Avoidable	$	594	$	3,705
4		Incremental	$	373	$	-
Campbell 2 retirement scenario						
5	JHCampbell 2					
6		Unavoidable	$	11,664	$	4,201
7		Avoidable	$	2,935	$	11,516
8		Incremental	$	100	$	1,000
Campbell 1 and 2 retirement scenario						
9	JHCampbell 1					
10		Unavoidable	$	10,549	$	2,970
11		Avoidable	$	594	$	3,705
12		Incremental	$	373	$	-
13	JHCampbell 2					
14		Unavoidable	$	11,664	$	4,201
15		Avoidable	$	2,935	$	11,516
16		Incremental	$	100	$	1,000
17	JHCampbell 3					
18		Unavoidable	$	17,094	$	26,562
19		Avoidable	$	-	$	-
20		Incremental	$	2,000	$	3,000
Karn 1 and 2 retirement scenario						
21	DEKarn 1&2					
22		Unavoidable	$	15,525	$	2,954
23		Avoidable	$	-	$	4,450
24		Incremental	$	-	$	2,100
25	DEKarn 3&4					
26		Unavoidable	$	8,957	$	10,800
27		Avoidable				
28		Incremental	$	17,000	$	3,000

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of the Generation O&M Expense
For the years 2017 through 12 Months Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-62 (JPB-5)
Page: 1 of 3
Witness: JPBroschak
Date: May 2018

GENERATION OPERATION AND MAINTENANCE EXPENSES

($000s)

Line No.	(a) Description	(b) Historical 12 Mos Ended 12/31/2017	(c) Projected 12 Mos Ending 12/31/2018	(d) Projected 12 Mos Ending 12/31/2019
1	**BASE O&M**	$ 101,973	$ 103,897	$ 107,981
2	**ADJUSTED O&M**			
3	Environmental Operations	$ 11,905	$ 12,302	$ 12,114
4	Major Maintenance	$ 17,750	$ 21,916	$ 48,996
5	**TOTAL O&M**	**$ 131,627**	**$ 138,114**	**$ 169,090**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of the Generation O&M Expense
For the years 2017 through 12 Months Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-62 (JPB-5)

Witness: JPBroschak
Date: May 2018

GENERATION OPERATION AND MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Mos Ended 12/31/2017	(c) Projected 12 Mos Ending 12/31/2018	(d) Projected 12 Mos Ending 12/31/2019
1	Labor	$ 81,429	$ 85,442	$ 104,604
2	Contractor	$ 18,171	$ 19,067	$ 23,343
3	Materials	$ 7,663	$ 8,041	$ 9,844
4	Other Non Labor	$ 24,364	$ 25,565	$ 31,299
5	Total	$ 131,627	$ 138,114	$ 169,090

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of the Generation Major Maintenance O&M Expense
For the Years 2017 through 12 Months Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-62 (JPB-5)

Witness: JPBroschak
Date: May 2018

GENERATION MAJOR MAINTENANCE EXPENSES

($000s)

	(a)	(b)	(c)	(d)
		Historical	**Projected**	
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**
1	**Major Maintenance**			
2	Campbell 1&2	$ 833	$ 1,878	$ 15,963
3	Campbell 3	$ 452	$ 1,799	$ 5,995
4	Karn 1&2	$ 3,032	$ 1,825	$ 1,387
5	Karn 3&4	$ -	$ -	$ 5,125
6	Cobb	$ 38	$ 340	$ 276
7	Whiting	$ 50	$ 144	$ 174
8	Zeeland Generating Station	$ 3,930	$ 6,081	$ 6,146
9	Jackson Generating Station	$ 3,510	$ 1,688	$ 1,000
10	Ludington	$ 2,621	$ 2,811	$ 3,257
11	Hydros	$ 3,232	$ 4,641	$ 8,309
12	Weadock	$ 52	$ 372	$ 160
13	Admin & Other	$ 0	$ 337	$ 1,204
	TOTAL Major Maintenance	**$ 17,750**	**$ 21,916**	**$ 48,996**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric O&M Major Maintenance Expenses
For the years 2017 through 2019

Case No.: U-20134
Exhibit No.: A-63 (JPB-6)

Witness: JPBroschak
Date: May 2018

Generation O&M Major Maintenance Expenses
AVOIDABLE UNDER AN EARLY RETIREMENT SCENARIO 2023
($000's)

Line No.	Description	2018 Projected	2019 Projected
	Campbell 1 retirement scenario		
1	JHCampbell 1		
2	Unavoidable	$ 1,096	$ 3,068
3	Avoidable	$ -	$ -
4	Incremental	$ -	$ -
	Campbell 2 retirement scenario		
5	JHCampbell 2		
6	Unavoidable	$ 782	$ 12,856
7	Avoidable	$ -	$ 39
8	Incremental	$ -	$ -
	Campbell 1 and 2 retirement scenario		
9	JHCampbell 1		
10	Unavoidable	$ 1,096	$ 3,068
11	Avoidable	$ -	$ -
12	Incremental	$ -	$ -
13	JHCampbell 2		
14	Unavoidable	$ 782	$ 12,856
15	Avoidable	$ -	$ 39
16	Incremental	$ -	$ -
	Karn 1 and 2 retirement scenario		
17	DEKarn 1&2		
18	Unavoidable	$ 1,825	$ 1,387
19	Avoidable	$ -	$ -
20	Incremental	$ -	$ -
21	DEKarn 3&4		
22	Unavoidable	$ 8,957	$ 10,800
23	Avoidable	$ -	$ -
24	Incremental	$ -	$ -

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric O&M Major Maintenance Expenses
For the years 2017 through 2019

Case No.: U-20134
Exhibit No.: A-63 (JPB-6)

Witness: JPBroschak
Date: May 2018

Generations O&M Major Maintenance Expenses
AVOIDABLE UNDER AN EARLY RETIREMENT SCENARIO 2021
($000's)

Line No.	Description		2018 Projected		2019 Projected
Campbell 1 retirement scenario					
1	JHCampbell 1				
2	Unavoidable	$	1,096	$	2,773
3	Avoidable	$	-	$	295
4	Incremental	$	-	$	700
Campbell 2 retirement scenario					
5	JHCampbell 2				
6	Unavoidable	$	782	$	12,256
7	Avoidable	$	-	$	640
8	Incremental	$	-	$	-
Campbell 1 and 2 retirement scenario					
9	JHCampbell 1				
10	Unavoidable	$	1,096	$	2,773
11	Avoidable	$	-	$	295
12	Incremental	$	-	$	700
13	JHCampbell 2				
14	Unavoidable	$	782	$	12,256
15	Avoidable	$	-	$	640
16	Incremental	$	-	$	-
Karn 1 and 2 retirement scenario					
17	DEKarn 1&2				
18	Unavoidable	$	1,825	$	936
19	Avoidable	$	-	$	452
20	Incremental	$	-	$	1,383
21	DEKarn 3&4				
22	Unavoidable	$	8,957	$	10,800
23	Avoidable	$	-	$	-
24	Incremental	$	-	$	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Non-Fuel O&M/MWh for 2016

Source: SNL Financial

Case No.: U-20134
Exhibit No.: A-64 (JPB-7)
Page: 1 of 1
Witness: JPBroschak
Date: May 2018

2016 Non-Fuel O&M / MWh

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	**Plant**	**No.**	**Capacity**	**Consumers Weighting**	**4 Quartile**	**3rd Quartile**	**Middle Quartile**	**2nd Quartile**	**1st Quartile**
1	Karn	1	256	13.23	30.63	18.36	11.79	7.56	3.58
2	Karn	2	256	13.23	30.63	18.36	11.79	7.56	3.58
3	Campbell	1	250	5.11	30.63	18.36	11.79	7.56	3.58
4	Campbell	2	350	5.11	30.63	18.36	11.79	7.56	3.58
5	Campbell	3	820	5.11	259.78	11.50	7.84	5.91	2.98
6				$6.74	$127.89	$15.45	$10.11	$6.86	$3.33

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

EXHIBITS

OF

LORA B. CHRISTOPHER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Electric Benefits O&M Expenses
For the Years 2017, 2018, and 2019
($000)

Case No.: U-20134
Exhibit No.: A-65 (LBC-1)
Page: 1 of 1
Witness: LBChristopher
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	Projected		
Line No.	Description	12 Mos. Ended 12/31/2017	12 Mos. Ending 12/31/2018	12 Mos. Ending 12/31/2019	Source
1	Pension Plans A/B	$ 25,890	$ 27,109	$ 26,573	WP-LBC- 1, 2, 11
2	Defined Company Contribution Plan	6,869	7,848	9,025	WP-LBC- 3, 4, 11
3	401 (k) Employees' Savings Plan	7,696	8,038	8,317	WP-LBC- 5, 6, 11
4	Active Health Care/Life Insurance/LTD	23,037	24,315	25,145	WP-LBC- 7, 8, 12
5	Retiree Health Care and Life Insurance	(20,311)	(55,475)	(57,129)	WP-LBC- 9, 10, 13
6	**Total Expense**	**$ 43,181**	**$ 11,835**	**$ 11,931**	

CMS Energy - Active Qualified Plan A
ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

Prepared on January 24, 2018

Line No.	(a) Description	(b) 2018	(c) 2019	(d) 2020	(e) 2021	(f) 2022	(g) 2023	(h) 2024	(i) 2025
1	Funding Target	$ 816.6	$ 897.4	$ 969.5	$ 1,081.5	$ 1,201.9	$ 1,326.7	$ 1,459.0	$ 1,519.7
2	Value of Plan Assets	$ 892.9	$ 876.1	$ 863.1	$ 872.2	$ 966.7	$ 1,078.5	$ 1,211.3	$ 1,352.0
3	Credit Balance	$ 239.6	$ 158.2	$ 69.9	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
4	Funded %	80.0%	80.0%	81.8%	80.6%	80.4%	81.3%	83.0%	89.0%
5	Effective Interest Rate	5.74%	5.60%	5.44%	5.01%	4.59%	4.19%	3.81%	3.76%
6	Contribution by Plan Year								
7	Utility	$ 0.0	$ 0.0	$ 24.9	$ 106.1	$ 123.2	$ 141.2	$ 145.9	$ 124.6
8	Nonutility	0.0	0.0	1.8	7.6	8.9	10.1	10.5	9.0
9	**Total**	**$ 0.0**	**$ 0.0**	**$ 26.7**	**$ 113.7**	**$ 132.1**	**$ 151.3**	**$ 156.4**	**$ 133.6**
10	At-Risk?	No	No	No	No	No	No	No	No
11	Benefit Restrictions?	No	No	No	No	No	No	No	No
12	Participant Count	3,518	3,396	3,335	3,265	3,188	3,107	3,030	2,953
13	PBGC Liability	$ 976.6	$ 1,083.9	$ 1,174.5	$ 1,229.7	$ 1,284.3	$ 1,337.8	$ 1,394.5	$ 1,448.7
14	Market Value of Assets	$ 892.9	$ 880.2	$ 870.2	$ 879.3	$ 976.3	$ 1,091.6	$ 1,229.7	$ 1,375.5
15	PBGC Flat Rate Premium	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3
16	PBGC Variable Rate Premium	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
17	**Total PBGC Premium**	**$ 2.1**	**$ 2.1**	**$ 2.1**	**$ 2.1**	**$ 2.1**	**$ 2.1**	**$ 2.1**	**$ 2.1**
18	Projected Benefit Obligation	$ 1,510.4	$ 1,585.8	$ 1,647.9	$ 1,704.0	$ 1,756.0	$ 1,802.2	$ 1,843.7	$ 1,881.4
19	Market Value of Assets	892.9	880.2	870.2	879.3	976.3	1,091.6	1,229.7	1,375.5
20	**Funded Status**	**$ 617.5**	**$ 705.6**	**$ 777.7**	**$ 824.7**	**$ 779.7**	**$ 710.6**	**$ 614.0**	**$ 505.9**
21	ASC 715 Funded %	59.1%	55.5%	52.8%	51.6%	55.6%	60.6%	66.7%	73.1%
22	**ASC 715 Accounting Expense**								
23	Utility	$ 96.9	$ 97.8	$ 97.8	$ 90.6	$ 79.9	$ 71.3	$ 64.6	$ 53.5
24	Nonutility	2.3	2.3	2.3	2.2	1.9	1.7	1.5	1.3
25	**Total**	**$ 99.2**	**$ 100.1**	**$ 100.1**	**$ 92.8**	**$ 81.8**	**$ 73.0**	**$ 66.1**	**$ 54.8**
26	**Components of Total Expense**								
27	Service Cost	$ 48.2	$ 47.4	$ 45.7	$ 43.6	$ 41.2	$ 39.5	$ 38.3	$ 36.4
28	Interest Cost	50.0	52.4	54.3	56.0	57.5	58.9	60.1	61.1
29	Expected Return on Assets	(56.3)	(55.1)	(52.5)	(54.4)	(60.1)	(67.5)	(73.5)	(82.5)
30	Amortization of Outstanding Components	57.3	55.4	52.6	47.6	43.2	42.1	41.2	39.8
31	**Total Expense**	**$ 99.2**	**$ 100.1**	**$ 100.1**	**$ 92.8**	**$ 81.8**	**$ 73.0**	**$ 66.1**	**$ 54.8**
32	**Assumptions**								
33	Discount Rate	3.78%	3.78%	3.77%	3.77%	3.76%	3.75%	3.74%	3.74%
34	Expected Return on Assets	7.00%	7.00%	6.75%	6.75%	6.50%	6.50%	6.25%	6.25%
35	Salary Increases	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%

CMS Energy - Inactive Qualified Plan B
ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

Prepared on January 24, 2018

Line No.	(a) Description	(b) 2018	(c) 2019	(d) 2020	(e) 2021	(f) 2022	(g) 2023	(h) 2024	(i) 2025
1	Funding Target	$ 1,020.5	$ 1,032.6	$ 1,014.5	$ 1,018.0	$ 1,018.6	$ 1,013.6	$ 1,004.3	$ 965.1
2	Value of Plan Assets	$ 1,449.2	$ 1,405.0	$ 1,418.7	$ 1,426.2	$ 1,431.3	$ 1,434.7	$ 1,438.9	$ 1,443.0
3	Credit Balance	$ 96.5	$ 103.2	$ 110.5	$ 117.9	$ 125.9	$ 134.1	$ 142.8	$ 151.7
4	Funded %	132.6%	126.1%	129.0%	128.5%	128.2%	128.3%	129.1%	133.8%
5	Effective Interest Rate	5.57%	5.43%	5.27%	4.84%	4.42%	4.03%	3.65%	3.59%
6	Contribution by Plan Year								
7	Utility	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
8	Nonutility	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Total**	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**
10	At-Risk?	No	No	No	No	No	No	No	No
11	Benefit Restrictions?	No	No	No	No	No	No	No	No
12	Participant Count	8,550	8,330	8,180	8,022	7,854	7,677	7,494	7,304
13	PBGC Liability	$ 1,193.9	$ 1,205.4	$ 1,178.0	$ 1,136.9	$ 1,094.6	$ 1,052.0	$ 1,008.7	$ 965.1
14	Market Value of Assets	$ 1,412.7	$ 1,420.8	$ 1,430.2	$ 1,437.9	$ 1,447.2	$ 1,454.9	$ 1,464.3	$ 1,472.3
15	PBGC Flat Rate Premium	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7
16	PBGC Variable Rate Premium	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Total PBGC Premium**	**$ 0.6**	**$ 0.7**	**$ 0.7**	**$ 0.7**	**$ 0.7**	**$ 0.7**	**$ 0.7**	**$ 0.7**
18	Projected Benefit Obligation	$ 1,270.0	$ 1,229.4	$ 1,187.9	$ 1,145.8	$ 1,103.0	$ 1,059.8	$ 1,016.1	$ 972.0
19	Market Value of Assets	1,412.7	1,420.8	1,430.2	1,437.9	1,447.2	1,454.9	1,464.3	1,472.3
20	**Funded Status**	**$ (142.7)**	**$ (191.4)**	**$ (242.3)**	**$ (292.1)**	**$ (344.2)**	**$ (395.1)**	**$ (448.2)**	**$ (500.3)**
21	ASC 715 Funded %	111.2%	115.6%	120.4%	125.5%	131.2%	137.3%	144.1%	151.5%
22	ASC 715 Accounting Expense								
23	Utility	$ (30.6)	$ (32.8)	$ (32.3)	$ (36.6)	$ (37.8)	$ (40.0)	$ (39.1)	$ (41.2)
24	Nonutility	(3.0)	(3.2)	(3.1)	(3.5)	(3.7)	(3.9)	(3.8)	(4.0)
25	**Total**	**$ (33.6)**	**$ (36.0)**	**$ (35.4)**	**$ (40.1)**	**$ (41.5)**	**$ (43.9)**	**$ (42.9)**	**$ (45.2)**
26	**Components of Total Expense**								
27	Service Cost	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
28	Interest Cost	39.7	38.3	36.8	35.3	33.8	32.4	30.9	29.4
29	Expected Return on Assets	(92.7)	(93.4)	(90.8)	(92.6)	(91.1)	(91.8)	(89.0)	(89.6)
30	Amortization of Outstanding Components	19.4	19.1	18.6	17.2	15.8	15.5	15.2	15.0
31	**Total Expense**	**$ (33.6)**	**$ (36.0)**	**$ (35.4)**	**$ (40.1)**	**$ (41.5)**	**$ (43.9)**	**$ (42.9)**	**$ (45.2)**
32	**Assumptions**								
33	Discount Rate	3.64%	3.63%	3.62%	3.61%	3.60%	3.58%	3.57%	3.55%
34	Expected Return on Assets	7.00%	7.00%	6.75%	6.75%	6.50%	6.50%	6.25%	6.25%
35	Salary Increases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

2018-2025 projections reflect the following:

-January 1, 2017 census data, updated to reflect changes through July 31, 2017.
-PBO discount rates of 3.79% (Plan A) and 3.64% (Plan B) in fiscal 2018, based on December 31, 2017 yield curve anlaysis.
-Service Cost effective interest rate of 3.85% (Plan A) for fiscal 2018, based on December 31, 2017 yield curve.
-Interest Cost effective interest rates of 3.39% (Plan A) and 3.24% (Plan B) in fiscal 2018, based on December 31, 2017 yield curve.
-MP-2017 mortality projection scale applies for lump sum purposes beginning as of January 1, 2018, and for funding purposes beginning as of January 1, 2019.
-December 31, 2017 market assets provided by CMS for disclosure purposes.
-Estimated 4044 allocation of assets between plans A and B, as reflected for disclosure purposes.
-Expected and actual asset returns drop 25 basis points every other year, starting with a drop to 6.75% in 2020.
-Other provisions, assumptions and methods are the same as those used for December 31, 2017 ASC 715 disclosures.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20134
Exhibit No.: A-67 (LBC-3)
Page: 1 of 1
Witness: LBChristopher
Date: May 2018

CMS Energy
ASC 715 OPEB Expense Estimates ($ millions)

Prepared on January 22, 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	2016	2017	2018	2019	2020	2021	2022	2023
1	**Funded Status, January 1**								
2	Accumulated Postretirement Benefit Obligation	$ (1,227)	$ (1,409)	$ (1,095)	$ (1,100)	$ (1,099)	$ (1,095)	$ (1,089)	$ (1,081)
3	Plan Assets at Fair Value	1,208	1,264	1,420	1,465	1,509	1,551	1,593	1,636
4	**Funded Status**	**$ (19)**	**$ (145)**	**$ 325**	**$ 365**	**$ 410**	**$ 456**	**$ 504**	**$ 555**
5	**ASC 715 Accounting Expense**								
6	Utility	$ (36)	$ (28)	$ (90)	$ (93)	$ (88)	$ (89)	$ (91)	$ (85)
7	Nonutility	(5)	(5)	(6)	(6)	(7)	(7)	(7)	(7)
8	**Total**	**$ (41)**	**$ (33)**	**$ (96)**	**$ (99)**	**$ (95)**	**$ (96)**	**$ (98)**	**$ (92)**
9	**Components of Total Expense**								
10	Service Cost	$ 18	$ 19	$ 17	$ 16	$ 16	$ 16	$ 15	$ 15
11	Interest Cost	47	49	36	36	36	36	35	35
12	Expected Return on Assets	(86)	(90)	(97)	(100)	(102)	(105)	(104)	(107)
13	Amortization of Net (Gain) or Loss	21	29	15	15	14	12	11	10
14	Amortization of Prior Service Cost	(41)	(40)	(67)	(66)	(59)	(55)	(55)	(45)
15	**Total Expense**	**$ (41)**	**$ (33)**	**$ (96)**	**$ (99)**	**$ (95)**	**$ (96)**	**$ (98)**	**$ (92)**
16	**Assumptions**								
17	APBO Discount Rate	4.70%	4.49%/3.86%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%
18	Service Cost Effective Interest Rate	4.75%	4.89%/4.09%	3.93%	3.93%	3.93%	3.93%	3.93%	3.93%
19	Interest Cost Effective Interest Rate	3.89%	3.79%/3.33%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%
20	Expected Return on Assets	7.25%	7.25%/7.00%	7.00%	7.00%	6.75%	6.75%	6.50%	6.50%
21	Trend Rate—Initial Pre-65	7.25%	7.00%	7.50%	7.25%	7.00%	6.75%	6.50%	6.25%
22	Trend Rate—Initial Post-65	8.00%	7.75%	8.00%	7.75%	7.25%	7.00%	6.75%	6.50%
23	Trend Rate—Ultimate	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
24	Trend Rate—Ultimate Year Pre-65	2027	2027	2027	2027	2027	2027	2027	2027
25	Trend Rate—Ultimate Year Post-65	2027	2027	2027	2027	2027	2027	2027	2027
26	**Expected Contribution**	**$ 0**	**$ 0**	**$ 0.4**	**$ 0.4**	**$ 0.4**	**$ 0.4**	**$ 0.4**	**$ 0.4**

2018-2023 expense projections reflect the following:
-January 1, 2017 census data.
-APBO discount rate of 3.74% in fiscal 2018+, based on December 31, 2017 yield curve.
-Service Cost effective interest rate of 3.93% in fiscal 2018+, based on December 31, 2017 yield curve.
-Interest Cost effective interest rate of 3.35% in fiscal 2018+, based on December 31, 2017 yield curve.
-December 31, 2017 market assets provided by CMS for fiscal 2018 expense.
-Projected contributions provided by CMS:
  -$0.4 million in all future years.
-Other provisions, assumptions and methods are the same as those used for December 31, 2017 ASC 715 disclosures.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief. ____	))))))	Case No. U-20134

EXHIBITS

OF

LAURA M. COLLINS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Schedule F-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenue by Rate Schedule
Total Revenues

Case No.: U-20134
Exhibit No.: A-16 (LMC-1)
Schedule: F-2
Page: 1 of 3
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Total Present Revenue	Total Proposed Revenue	Total Net Increase/ (Decrease)	Total Net Increase/ (Decrease)
		$000	$000	$000	%
	Bundled Service				
	Residential Class				
1	Residential RS/Summer On Pk	$ 1,891,695	$ 1,917,413	$ 25,718	1.4
2	Residential RT	8,049	8,615	565	7.0
3	Residential REV	1,534	1,587	53	3.5
4	Residential RDP	10,764	11,268	504	4.7
5	Residential RDPR	8,193	8,461	268	3.3
6	Residential Opt Out	18,186	18,406	220	1.2
7	Total Residential Class	1,938,420	1,965,750	27,329	1.4
	Secondary Class				
8	Secondary Energy-only GS	571,320	591,620	20,299	3.6
9	Secondary Demand GSD	482,355	475,016	(7,339)	(1.5)
10	Secondary Energy-only GS TOU	-	-	-	NA
11	Total Secondary Class	1,053,675	1,066,635	12,960	1.2
	Primary Class				
12	Primary Energy-only GP	163,806	154,696	(9,110)	(5.6)
13	Primary Demand GPD	872,195	901,724	29,529	3.4
14	Primary Energy Intensive Rate EIP	22,052	22,744	691	3.1
15	Primary Time of Use Pilot GPTU	63,141	62,068	(1,073)	(1.7)
16	Total Primary Class	1,121,194	1,141,232	20,037	1.8
	Lighting & Unmetered Class				
17	Metered Lighting Service GML	1,755	2,032	277	15.8
18	Unmetered Lighting Service GUL	33,335	36,642	3,306	9.9
19	Unmetered Exp. Lighting GU-XL	2	3	1	61.8
20	Unmetered Service GU	8,391	8,103	(288)	(3.4)
21	Total Lighting & Unmetered Class	43,483	46,779	3,296	7.6
	Self-generation Class				
22	Small Self-generation GSG-1	-	-	-	NA
23	Large Self-generation GSG-2	3,584	1,841	(1,742)	NA
24	Total Self-Generation Class	3,584	1,841	(1,742)	NA
25	Total Bundled Service	$ 4,160,357	$ 4,222,238	$ 61,880	1.5
	ROA Service				
	Residential Class				
26	Residential Service RS	$ -	$ -	$ -	NA
27	Residential Time-of-Day RT	-	-	-	NA
28	Total Residential Class	-	-	-	NA
	Secondary Class				
29	Secondary Energy-only GS	950	979	29	3.1
30	Secondary Demand GSD	7,927	7,239	(688)	(8.7)
31	Total Secondary Class	8,877	8,218	(659)	(7.4)
	Primary Class				
32	Primary Energy-only GP	1,241	996	(245)	(19.8)
33	Primary Demand GPD	20,872	19,354	(1,518)	(7.3)
34	Total Primary Class	22,113	20,350	(1,763)	(8.0)
35	Total ROA Service	$ 30,990	$ 28,568	$ (2,422)	(7.8)
36	Total Bundled and ROA Service	$ 4,191,347	$ 4,250,806	$ 59,459	1.4

Notes

Schedule F-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenue by Rate Schedule
Power Supply Revenues

Case No.: U-20134
Exhibit No.: A-16 (LMC-1)
Schedule: F-2
Page: 2 of 3
Witness: LMCollins
Date: May 2018

Line No.	(a) Description	(b) Total Present Revenue	(c) Total Proposed Revenue	(d) Total Net Increase/ (Decrease)	(e) Total Net Increase/ (Decrease)
		$000	$000	$000	%
	Bundled Service				
	Residential Class				
1	Residential RS/Summer On Pk	$ 1,179,762	$ 1,217,074	$ 37,312	3.2
2	Residential RT	4,953	5,603	650	13.1
3	Residential REV	960	1,012	52	5.4
6	Residential RDP	6,098	6,640	541	8.9
7	Residential RDPR	4,656	4,924	269	5.8
8	Residential Opt Out	11,497	11,849	351	3.1
9	Total Residential Class	1,207,926	1,247,101	39,175	3.2
	Secondary Class				
10	Secondary Energy-only GS	362,471	377,607	15,136	4.2
11	Secondary Demand GSD	337,807	342,579	4,772	1.4
12	Secondary Energy-only GS TOU	-	-	-	NA
13	Total Secondary Class	700,278	720,186	19,908	2.8
	Primary Class				
14	Primary Energy-only GP	138,339	134,080	(4,259)	(3.1)
15	Primary Demand GPD	772,556	798,365	25,808	3.3
16	Primary Energy Intensive Rate EIP	21,309	22,685	1,377	6.5
15	Primary Time of Use Pilot GPTU	55,393	55,032	(360)	(0.7)
17	Total Primary Class	987,597	1,010,162	22,565	2.3
	Lighting & Unmetered Class				
18	Metered Lighting Service GML	758	1,043	285	37.6
19	Unmetered Lighting Service GUL	6,000	8,244	2,244	37.4
20	Unmetered Exp. Lighting GU-XL	1	1	(0)	(20.0)
21	Unmetered Service GU	6,835	6,535	(300)	(4.4)
22	Total Lighting & Unmetered Class	13,594	15,823	2,229	16.4
	Self-generation Class				
23	Small Self-generation GSG-1	-	-	-	NA
24	Large Self-generation GSG-2	1,548	-	(1,548)	(100.0)
25	Total Self-Generation Class	1,548	-	(1,548)	(100.0)
26	Total Bundled Service	$ 2,910,943	$ 2,993,272	$ 82,330	2.8
	ROA Service				
	Residential Class				
27	Residential Service RS	$ -	$ -	$ -	NA
28	Residential Time-of-Day RT	-	-	-	NA
29	Total Residential Class	-	-	-	NA
	Secondary Class				
30	Secondary Energy-only GS	-	-	-	NA
31	Secondary Demand GSD	-	-	-	NA
32	Total Secondary Class	-	-	-	NA
	Primary Class				
33	Primary Energy-only GP	-	-	-	NA
34	Primary Demand GPD	-	-	-	NA
35	Total Primary Class	-	-	-	NA
36	Total ROA Service	$ -	$ -	$ -	NA
37	Total Bundled and ROA Service	$ 2,910,943	$ 2,993,272	$ 82,330	2.8

Notes

Schedule F-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenue by Rate Schedule
Delivery Revenues

Case No.: U-20134
Exhibit No.: A-16 (LMC-1)
Schedule: F-2
Page: 3 of 3
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Total Present Revenue	Total Proposed Revenue	Total Net Increase/ (Decrease)	Total Net Increase/ (Decrease)
		$000	$000	$000	%
	Bundled Service				
	Residential Class				
1	Residential RS/Summer On Pk	$ 711,933	$ 700,339	$ (11,594)	(1.6)
2	Residential RT	3,096	3,012	(85)	(2.7)
3	Residential REV	574	575	1	0.2
6	Residential RDP	4,665	4,628	(37)	(0.8)
7	Residential RDPR	3,537	3,537	(0)	(0.0)
8	Residential Opt Out	6,689	6,558	(131)	(2.0)
9	Total Residential Class	730,494	718,649	(11,846)	(1.6)
	Secondary Class				
10	Secondary Energy-only GS	208,849	214,013	5,164	2.5
11	Secondary Demand GSD	144,548	132,437	(12,112)	(8.4)
12	Secondary Energy-only GS TOU	-	-	-	NA
13	Total Secondary Class	353,397	346,449	(6,948)	(2.0)
	Primary Class				
14	Primary Energy-only GP	25,466	20,616	(4,850)	(19.0)
15	Primary Demand GPD	99,639	63,420	(36,219)	(36.4)
16	Primary Energy Intensive Rate EIP	744	59	(685)	(92.1)
17	Primary Time of Use Pilot GPTU	7,748	7,035	(713)	(9.2)
18	Total Primary Class	133,597	91,130	(42,467)	(31.8)
	Lighting & Unmetered Class				
19	Metered Lighting Service GML	997	988	(9)	(0.9)
20	Unmetered Lighting Service GUL	27,335	28,397	1,062	3.9
21	Unmetered Exp. Lighting GU-XL	1	2	1	124.6
22	Unmetered Service GU	1,557	1,568	12	0.8
23	Total Lighting & Unmetered Class	29,890	30,956	1,067	3.6
	Self-generation Class				
24	Small Self-generation GSG-1	-	-	-	NA
25	Large Self-generation GSG-2	2,036	1,841	(194)	(9.6)
26	Total Self-Generation Class	2,036	1,841	(194)	(9.6)
27	Total Bundled Service	$ 1,249,415	$ 1,189,026	$ (60,389)	(4.8)
	ROA Service				
	Residential Class				
28	Residential Service RS	$ -	$ -	$ -	NA
29	Residential Time-of-Day RT	-	-	-	NA
30	Total Residential Class	-	-	-	NA
	Secondary Class				
31	Secondary Energy-only GS	950	979	29	3.1
32	Secondary Demand GSD	7,927	7,239	(688)	(8.7)
33	Total Secondary Class	8,877	8,218	(659)	(7.4)
	Primary Class				
34	Primary Energy-only GP	1,241	996	(245)	(19.8)
35	Primary Demand GPD	20,872	19,354	(1,518)	(7.3)
36	Total Primary Class	22,113	20,350	(1,763)	(8.0)
37	Total ROA Service	$ 30,990	$ 28,568	$ (2,422)	(7.8)
38	Total Bundled and ROA Service	$ 1,280,405	$ 1,217,594	$ (62,811)	(4.9)

Notes

Schedule F-2.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-2)
Schedule: F-2.1
Page: 1 of 1
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
Line			Residential Class		Secondary Class				Primary Class					Lighting & Unmetered Class				Self Gen. Class	
No.	Description	Jurisdictional	RS	RT	GS	GS GEI	GSD	GSD GEI	GP	GP GEI	GPD [3]	GPD GEI	EIP	GML	GUL	GU-XL	GU	GSG-1	GSG-2
	Cost-of-Service Study																		
	Power Supply (1)																		
1	Capacity	$ 1,030,867	$ 454,908	$ -	$ 131,901	$ 3,091	$ 114,632	$ 6,094	$ 48,809	$ 5,250	$ 252,878	$ 10,680	$ 800	$ -	$ -	$ -	$ 1,825	$ -	$ -
2	COSS Capacity	1,030,867	448,627	-	130,081	3,049	113,049	6,010	36,388	5,190	275,896	10,557	-	-	-	-	1,800	-	219
3	Interruptible	-	6,185	-	1,793	42	1,558	83	502	72	(10,405)	146	-	-	-	-	25	-	-
4	EIP Capacity	-							(88.74)	(12.66)	(672.85)	(25.75)	800	-	-	-	-		
5	Interclass Cross Pt Adj	-							12,000		(12,000)								
6	Self-Generation	-	96	-	28	1	24	1	8	1	59	2	-	-	-	-	0	-	(219)
7	Energy	1,973,806	782,428	-	233,909	5,658	207,402	11,560	68,436	10,464	598,304	20,158	21,579	1,031	8,239	1	4,637	-	-
8	COSS Energy	1,973,806	781,880	-	233,745	5,654	207,257	11,552	68,388	10,457	597,886	20,144	21,564	1,030	8,233	1	4,633	-	1,381
9	Self-Generation	(0)	548	-	164	4	145	8	48	7	419	14	15	1	6	0	3	-	(1,381)
10	Total Power Supply	3,004,673	1,237,336	-	365,811	8,749	322,034	17,654	117,245	15,715	851,182	30,837	22,379	1,031	8,239	1	6,462	-	-
	Delivery																		
11	Distribution	1,029,044	584,011	-	173,128	6,920	119,791	12,885	15,143	3,521	75,882	6,146	1,192	968	27,902	2	1,545	-	8
12	Customer	190,752	145,506	-	31,773	285	4,444	206	1,949	244	5,460	337	100	21	404	0	23	-	-
13	Total Delivery	1,219,796	729,516	-	204,902	7,205	124,236	13,091	17,091	3,765	81,342	6,483	1,292	988	28,306	2	1,568	-	8
14	Total Cost-of-Service	$ 4,224,469	$ 1,966,852	$ -	$ 570,712	$ 15,954	$ 446,269	$ 30,745	$ 134,336	$ 19,479	$ 932,524	$ 37,320	$ 23,671	$ 2,020	$ 36,545	$ 3	$ 8,030	$ -	$ 8
	Skewing and Discounts (2)																		
15	Senior Citizen	-	(8,173)	-	2,169		1,763		569		3,585		88	-	-	-	-	-	-
16	Income Assistance	-	(2,705)	-	718		584		188		1,187		29	-	-	-	-	-	-
17	Total Skewing and Discounts	-	(10,879)	-	2,887		2,347		757		4,772		116	-	-	-	-	-	-
18	Total Rate Design Target	$ 4,224,469	$ 1,955,973	$ -	$ 573,599	$ 15,954	$ 448,616	$ 30,745	$ 135,093	$ 19,479	$ 937,296	$ 37,320	$ 23,787	$ 2,020	$ 36,545	$ 3	$ 8,030	$ -	$ 8

Notes

(1) Capacity and energy costs adjusted to capture elements occurring outside the Cost-of-Service Study.
(2) Skewing and Discount Allocation Factors.

Jurisdictional	RS	RT	GS	GSD	GP	GPD	EIP	GML	GUL	GU-XL	GU	GSG-1	GSG-2
1.0000	0.4708	-	0.1404	0.1142	0.0368	0.2321	0.0057	-	-	-	-	-	-

(3) Voltage Levels combined when entering from COSS.

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Residential Service Summer On Peak

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
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Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	First 600 kWh/mth	2,840,898	MWh	0.061776	$ 175,499		$ -
2	Excess kWh/mth	1,390,911	MWh	0.083153	115,658		-
3	On Peak	658,073	MWh			0.092646	60,968
4	Off Peak	3,573,736	MWh			0.062374	222,908
	Capacity						
5	First 600 kWh/mth	2,840,898	MWh	0.032749	93,037		-
6	Excess kWh/mth	1,390,911	MWh	0.044082	61,314		-
7	On Peak	658,073				0.054145	35,631
8	Off Peak	3,573,736				0.036453	130,273
9	Total Summer Power Supply	4,231,809			445,508		449,781
10	Peak Saver	288,000	Bills	(7.84)	(2,258)	(8.00)	(2,304)
11	Peak Time Rewards	-				(0.95)	-
	Winter (Oct. - May)						
12	Non Capacity All kWh/mth	7,690,800	MWh	0.061776	475,107	0.062374	479,706
13	Capacity All kWh/mth	7,690,800	MWh	0.032749	251,866	0.036453	280,353
14	Annual PSCR Factor kWh/mth	11,922,609	MWh	0.000800	9,538	0.000800	9,538
15	Total Power Supply				$ 1,179,762		$ 1,217,074
	Delivery						
16	Distribution kWh/mth	11,922,609	MWh	0.050297	$ 599,671	0.048652	$ 580,059
17	System Access	18,778,162	Bills	7.00	131,447	7.50	140,836
	Provisions						
18	Senior Citizen RSC	4,118,400	Bills	(3.50)	(14,414)	(3.75)	(15,444)
19	Income Assistance RIA	681,600	Bills	(7.00)	(4,771)	(7.50)	(5,112)
20	Total Delivery				$ 711,933		$ 700,339
	ROA Service						
	Delivery						
21	Distribution kWh/mth	-	MWh	0.050297	$ -	0.048652	$ -
22	System Access	-	Bills	7.00	-	7.50	-
23	Provisions						
24	Senior Citizen RSC	-	Bills	(3.50)	-	(3.75)	-
25	Income Assistance RIA	-	Bills	(7.00)	-	(7.50)	-
26	Total Delivery				$ -		$ -
27	Total Residential RS				$ 1,891,695		$ 1,917,413

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

Residential Service RS Smart Meter Opt Out

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Billing Determinants		**Present**		**Proposed**	
Line No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	First 600 kWh/mth	26,510	MWh	0.061776	$ 1,638	0.061770	$ 1,637
2	Excess kWh/mth	12,981	MWh	0.083153	1,079	0.081689	1,060
	Capacity						
3	First 600 kWh/mth	26,510	MWh	0.032749	868	0.035913	952
4	Excess kWh/mth	12,981	MWh	0.044082	572	0.047494	617
5	Total Summer Power Supply	39,491			4,158		4,267
	Winter (Oct. - May)						
	Non Capacity						
6	All kWh/mth	76,667	MWh	0.061776	4,736	0.061770	4,736
	Capacity						
7	All kWh/mth	76,667	MWh	0.032749	2,511	0.035913	2,753
8	Annual PSCR Factor kWh/mth	116,158	MWh	0.000800	93	0.000800	93
9	Total Power Supply				$ 11,497		$ 11,849
	Delivery						
10	Distribution kWh/mth	116,158	MWh	0.050297	$ 5,842	0.048652	$ 5,651
11	Skewing			(0.000855)		(0.000890)	
12	System Access	120,879	Bills	7.00	846	7.50	907
	Provisions						
13	Senior Citizen RSC	-	Bills	(3.50)	-	(3.75)	-
14	Income Assistance RIA	-	Bills	(7.00)	-	(7.50)	-
15	Total Delivery				$ 6,689		$ 6,558
	ROA Service						
	Delivery						
16	Distribution kWh/mth	-	MWh	0.050297	$ -	0.048652	$ -
17	System Access	-	Bills	7.00	-	7.50	-
18	Provisions						
19	Senior Citizen RSC	-	Bills	(3.50)	-	(3.75)	-
20	Income Assistance RIA	-	Bills	(7.00)	-	(7.50)	-
21	Total Delivery				$ -		$ -
22	Total Residential RS				$ 18,186		$ 18,406

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Residential Dynamic Pricing RDP

Case No.: U-20134
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Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	Off-peak kWh/mth	15,291	MWh	0.041976	$ 642	0.049820	$ 762
2	Mid-peak kWh/mth	11,578	MWh	0.058503	677	0.070884	821
3	On-peak kWh/mth	3,588	MWh	0.073248	263	0.090211	324
4	Critical-peak kWh/mth	-	MWh	0.614634	-	0.600732	-
	Capacity						
5	Off-peak kWh/mth	15,291	MWh	0.017318	$ 265	0.028966	$ 443
6	Mid-peak kWh/mth	11,578	MWh	0.024136	279	0.041213	477
7	On-peak kWh/mth	3,588	MWh	0.030219	108	0.052450	188
8	Critical-peak kWh/mth	-	MWh	0.335366	-	0.349268	-
9	Total Summer Power Supply	30,456			2,235		3,014
	Winter (Oct. - May)						
	Non Capacity						
10	Off-peak kWh/mth	20,157	MWh	0.057435	1,158	0.049820	1,004
11	On-peak kWh/mth	20,093	MWh	0.066212	1,330	0.062338	1,253
	Capacity						
12	Off-peak kWh/mth	20,157	MWh	0.030448	614	0.028966	584
12	On-peak kWh/mth	20,093	MWh	0.035101	705	0.036244	728
13	Total Winter Power Supply				3,807		3,569
14	Annual PSCR Factor kWh/mth	70,706	MWh	0.000800	57	0.000800	57
15	Total Power Supply				$ 6,098		$ 6,640
	Delivery						
16	Distribution kWh/mth	70,706	MWh	0.050297	$ 3,556	0.048652	$ 3,440
17	System Access	158,442	Bills	7.00	1,109	7.50	1,188
	Provisions						
18	Senior Citizen RSC	-	Bills	(3.50)	-	(3.75)	-
19	Income Assistance RIA	-	Bills	(7.00)	-	(7.50)	-
20	Total Delivery				$ 4,665		$ 4,628
21	Total Residential RDP				$ 10,764		$ 11,268

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

Residential Dynamic Pricing Rewards RDPR

	(a)	(b)	(c)	(d)		(e)	(f)		(g)
Line		**Billing Determinants**		**Present**			**Proposed**		
No.	**Description**	**Quantity**	**Units**	**Rates**		**Revenue**	**Rates**		**Revenue**
				$/unit		$000	$/unit		$000
	Bundled Service								
	Power Supply								
	Summer (June - Sept.)								
	Non Capacity								
1	Off-peak kWh/mth	10,513	MWh	0.050762	$	534	0.058284	$	613
2	Mid-peak kWh/mth	8,191	MWh	0.070748		580	0.082665		677
3	On-peak kWh/mth	2,783	MWh	0.088580		246	0.105021		292
4	Critical-peak kWh/mth	-	MWh	(0.614634)		-	(0.600732)		-
	Capacity								
5	Off-peak kWh/mth	10,513	MWh	0.026802	$	282	0.033886	$	356
6	Mid-peak kWh/mth	8,191	MWh	0.037354		306	0.048061		394
7	On-peak kWh/mth	2,783	MWh	0.046769		130	0.061059		170
8	Critical-peak kWh/mth	-	MWh	(0.335366)		-	(0.349268)		-
9	Total Summer Power Supply	21,487				2,078			2,502
	Winter (Oct. - May)								
	Non Capacity								
10	Off-peak kWh/mth	12,990	MWh	0.057435		746	0.049820		647
11	On-peak kWh/mth	13,798	MWh	0.066212		914	0.062338		860
	Capacity								
12	Off-peak kWh/mth	12,990	MWh	0.030448		396	0.028966		376
13	On-peak kWh/mth	13,798	MWh	0.035101		484	0.036244		500
14	Total Winter Power Supply					2,540			2,384
15	Annual PSCR Factor kWh/mth	48,275	MWh	0.000800		39	0.000800		39
16	Total Power Supply				$	4,656		$	4,924
	Delivery								
17	Distribution kWh/mth	48,275	MWh	0.050297	$	2,428	0.048652	$	2,349
18	System Access	158,442	Bills	7.00		1,109	7.50		1,188
	Provisions								
19	Senior Citizen RSC	-	Bills	(3.50)		-	(3.75)		-
20	Income Assistance RIA	-	Bills	(7.00)		-	(7.50)		-
21	Total Delivery				$	3,537		$	3,537
22	Total Residential RDPR				$	8,193		$	8,461

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

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Residential Electric Vehicle REV-1 (Home & Vehicle)

Line No.	Description (a)	Billing Determinants Quantity (b)	Units (c)	Present Rates (d)	Present Revenue (e)	Proposed Rates (f)	Proposed Revenue (g)
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	On-peak kWh/mth	462	MWh	0.095794	$ 44	0.099465	$ 46
2	Mid-peak kWh/mth	1,235	MWh	0.076510	95	0.078155	97
3	Off-peak kWh/mth	1,713	MWh	0.054896	94	0.054931	94
	Capacity						
4	On-peak kWh/mth	462	MWh	0.050711	$ 23	0.057830	$ 27
5	Mid-peak kWh/mth	1,235	MWh	0.040502	50	0.045440	56
6	Off-peak kWh/mth	1,713	MWh	0.029061	50	0.031937	55
7	Total Summer Power Supply	3,410			356		374
	Winter (Oct. - May)						
	Non Capacity						
8	On-peak kWh/mth	3,011	MWh	0.063285	191	0.068734	207
9	Off-peak kWh/mth	3,560	MWh	0.054896	195	0.054931	196
	Capacity						
10	On-peak kWh/mth	3,011	MWh	0.033502	101	0.039962	120
11	Off-peak kWh/mth	3,560	MWh	0.029061	103	0.031937	114
12	Total Winter Power Supply	6,572			590		637
13	Annual PSCR Factor kWh/mth	9,982	MWh	0.000800	8	0.000800	8
14	Total Power Supply				$ 954		$ 1,019
	Delivery						
15	Distribution kWh/mth	9,982	MWh	0.050297	$ 502	0.048652	$ 486
16	System Access	9,780	Bills	7.00	68	7.50	73
17	Total Delivery				$ 571		$ 559
18	Total Residential REV-1				$ 1,525		$ 1,578

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Residential Electric Vehicle REV-2 (Vehicle Only Time-of-Day)

Case No.: U-20134
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Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	On-peak kWh/mth	-	MWh	0.095794	$ -	0.099465	$ -
2	Mid-peak kWh/mth	3	MWh	0.076510	0	0.078155	0
3	Off-peak kWh/mth	15	MWh	0.054896	1	0.054931	1
	Capacity						
4	On-peak kWh/mth	-	MWh	0.050711	$ -	0.057830	$ -
5	Mid-peak kWh/mth	3	MWh	0.040502	0	0.045440	0
6	Off-peak kWh/mth	15	MWh	0.029061	0	0.031937	0
7	Total Summer Power Supply	18			2		2
	Winter (Oct. - May)						
	Non Capacity						
8	On-peak kWh/mth	14	MWh	0.063285	1	0.068734	1
9	Off-peak kWh/mth	33	MWh	0.054896	2	0.054931	2
	Capacity						
10	On-peak kWh/mth	14	MWh	0.033502	0	0.039962	1
11	Off-peak kWh/mth	33	MWh	0.029061	1	0.031937	1
12	Total Winter Power Supply	47			4		4
13	Annual PSCR Factor kWh/mth	66	MWh	0.000800	0	0.000800	0
14	Total Power Supply				$ 6		$ 6
	Delivery						
15	Distribution kWh/mth	66	MWh	0.050297	$ 3	0.048652	$ 3
16	Total Residential REV-2				$ 9		$ 9

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Residential Time-of-Day RT

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	(a)	(b)	(c)	(d)	(e)		(f)	(g)	
		Billing Determinants		**Present**			**Proposed**		
Line No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**		**Rates**	**Revenue**	
				$/unit	$000		$/unit	$000	
	Bundled Service								
	Power Supply								
	Summer (June - Sept.)								
	Non Capacity								
1	On-peak kWh/mth	3,692	MWh	0.081273	$	300	0.079745	$	294
2	Off-peak kWh/mth	13,364	MWh	0.056314		753	0.054774		732
	Capacity								
3	On-peak kWh/mth	3,692	MWh	0.031800		117	0.046364	$	171
4	Off-peak kWh/mth	13,364	MWh	0.022034		294	0.031846		426
5	Total Summer Power Supply	17,056				1,465			1,623
	Winter (Oct. - May)								
	Non Capacity								
6	On-peak kWh/mth	8,913	MWh	0.065553		584	0.066639		594
7	Off-peak kWh/mth	32,435	MWh	0.058255		1,890	0.058363		1,893
	Capacity								
8	On-peak kWh/mth	8,913	MWh	0.025649		229	0.038744		345
9	Off-peak kWh/mth	32,435	MWh	0.022794		739	0.033932		1,101
10	Total Winter Power Supply	41,348				3,442			3,933
11	Annual PSCR Factor kWh/mth	58,404	MWh	0.000800		47	0.000800		47
12	Total Power Supply				$	4,953		$	5,603
	Delivery								
13	Distribution kWh/mth	58,404	MWh	0.050297	$	2,938	0.048652	$	2,841
14	System Access	26,952	Bills	7.00		189	7.50		202
	Provisions								
15	Senior Citizen RSC	7,224	Bills	(3.50)		(25)	(3.75)		(27)
16	Income Assistance RIA	636	Bills	(7.00)		(4)	(7.50)		(5)
17	Total Delivery				$	3,096		$	3,012
	ROA Service								
	Delivery								
18	Distribution kWh/mth	-	MWh	0.050297	$	-	0.048652	$	-
19	System Access	-	Bills	7.00		-	7.50		-
	Provisions								
20	Senior Citizen RSC	-	Bills	(3.50)		-	(3.75)		-
21	Income Assistance RIA	-	Bills	(7.00)		-	(7.50)		-
22	Total Delivery				$	-		$	-
23	Total Residential RT				$	8,049		$	8,615

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Residential Service Smart Hours Rate

Case No.: U-20134
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Billing Determinants		Present		Proposed	
Line No.	Description	Quantity	Units	Rates	Revenue	Rates	Revenue
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Proposed Smart Hours						
	Non Capacity						
1	On Peak		MWh			0.089856	-
2	Off Peak		MWh			0.060495	-
	Capacity						
3	On Peak					0.052243	-
4	Off Peak					0.035172	-
5	Total Summer Power Supply				-		-
6	Peak Saver		Bills	(7.84)		(8.00)	-
7	Peak Time Rewards					(0.95)	-
	Winter (Oct. - May)						
	Non Capacity						
8	On Peak					0.067925	-
9	Off Peak					0.060495	-
	Capacity						
10	On Peak					0.039492	-
11	Off Peak					0.035172	-
12	Total Winter Power Supply				-		-
13	Annual PSCR Factor kWh/mth		MWh	0.000800	-	0.000800	-
14	Total Power Supply				$ -		$ -
	Delivery						
15	Distribution kWh/mth		MWh	0.050297	$ -	0.048652	$ -
16	System Access		Bills	7.00	-	7.50	-
	Provisions						
17	Senior Citizen RSC		Bills	(3.50)	-	(3.75)	-
18	Income Assistance RIA		Bills	(7.00)	-	(7.50)	-
19	Total Delivery				$ -		$ -
	ROA Service						
	Delivery						
20	Distribution kWh/mth	-	MWh	0.050297	$ -	0.048652	$ -
21	System Access	-	Bills	7.00	-	7.50	-
22	Provisions						
23	Senior Citizen RSC	-	Bills	(3.50)	-	(3.75)	-
24	Income Assistance RIA	-	Bills	(7.00)	-	(7.50)	-
25	Total Delivery				$ -		$ -
26	Total Residential Smart Savers				$ -		$ -

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Residential Service Nighttime Savers Rate

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
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Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Billing Determinants		**Present**		**Proposed**	
Line No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Proposed Nighttime Savers						
	Non Capacity						
1	On-peak kWh/mth					0.092077	-
2	Off-peak kWh/mth					0.073762	-
3	Super-peak kWh/mth					0.052419	-
	Capacity						
4	On-peak kWh/mth					0.053534	-
5	Off-peak kWh/mth					0.042886	-
6	Super-peak kWh/mth					0.030477	-
7	*Total Summer Power Supply*				-		-
	Winter (Oct. - May)						
	Non Capacity						
8	On-peak kWh/mth					0.067731	-
9	Off-peak kWh/mth					0.065077	-
10	Super-peak kWh/mth					0.052419	-
	Capacity						
11	On-peak kWh/mth					0.039379	-
12	Off-peak kWh/mth					0.037836	-
13	Super-peak kWh/mth					0.030477	-
14	Total Winter Power Supply				-		-
15	Annual PSCR Factor kWh/mth		MWh	0.000800	-	0.000800	-
16	Total Power Supply				$ -		$ -
	Delivery						
17	Distribution kWh/mth		MWh	0.050297	$ -	0.048652	$ -
18	System Access		Bills	7.00	-	7.50	-
	Provisions						
19	Senior Citizen RSC		Bills	(3.50)	-	(3.75)	-
20	Income Assistance RIA		Bills	(7.00)	-	(7.50)	-
21	Total Delivery				$ -		$ -
	ROA Service						
	Delivery						
22	Distribution kWh/mth		MWh	0.050297	$ -	0.048652	$ -
23	System Access		Bills	7.00	-	7.50	-
24	Provisions						
25	Senior Citizen RSC		Bills	(3.50)	-	(3.75)	-
26	Income Assistance RIA		Bills	(7.00)	-	(7.50)	-
27	Total Delivery				$ -		$ -
28	Total Residential Nighttime Savers				$ -		$ -

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Secondary Energy-only GS

Case No.: U-20134
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Date: May 2018

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	
Line		Billing Determinants		Present			Proposed		
No.	Description	Quantity	Units	Rates	Revenue		Rates	Revenue	
				$/unit	$000		$/unit	$000	
	Bundled Service								
	Power Supply								
	Summer (June - Sept.)								
	Non Capacity								
1	All kWh/mth	1,394,787	MWh	0.064823	$	90,414	0.063270	$	88,248
2	Capacity								
3	All kWh/mth	1,394,787	MWh	0.031976	$	44,600	0.035652	$	49,727
	Provisions								
4	Education GEI	25,295	MWh	-		-			-
5	Total Summer Power Supply					135,014			137,975
	Winter (Oct. - May)								
	Non Capacity								
6	All kWh/mth	2,416,086	MWh	0.062199		150,278	0.062629		151,317
7	Capacity								
8	All kWh/mth	2,416,086	MWh	0.030682		74,130	0.035291		85,266
	Provisions								
9	Education GEI	63,672	MWh	-		-			-
10	Total Winter Power Supply					224,408			236,583
11	Annual PSCR Factor kWh/mth	3,810,873	MWh	0.000800		3,049	0.000800		3,049
12	Total Power Supply				$	362,471		$	377,607
	Delivery								
13	Distribution kWh/mth	3,810,873	MWh	0.042598	$	162,336	0.043954	$	167,503
14	Skewing			0.000708			0.000753		
15	System Access	2,328,830	Bills	20.00		46,577	20.00		46,577
	Provisions								
16	Education GEI	88,967	MWh	(0.000708)		(63)	(0.000753)		(67)
17	Total Delivery				$	208,849		$	214,013
	ROA Service								
	Delivery								
18	Distribution kWh/mth	21,922	MWh	0.042598	$	934	0.043954	$	964
19	System Access	1,331	Bills	20.00		27	20.00		27
20	Provisions								
21	Education GEI	15,206	MWh	(0.000708)		(11)	(0.000753)		(11)
22	Total Delivery				$	950		$	979
23	Total Secondary GS				$	572,270		$	592,598

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Secondary Time of Use GSTU

Case No.: U-20134
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Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	Off-peak kWh/mth	-	MWh	0.059790	$ -	0.056440	$ -
2	Mid-peak kWh/mth	-	MWh	0.090451	-	0.087862	-
3	On-peak kWh/mth	-	MWh	0.113249	-	0.111819	-
	Capacity						
4	Off-peak kWh/mth	-	MWh	0.029494	$ -	0.031804	$ -
5	Mid-peak kWh/mth	-	MWh	0.044618	-	0.049510	-
6	On-peak kWh/mth	-	MWh	0.055864	-	0.063009	-
	Provisions						
7	Education GEI	-	MWh		-	-	-
8	Total Summer Power Supply	-			-		-
	Winter (Oct. - May)						
	Non Capacity						
9	Off-peak kWh/mth	-	MWh	0.051063	-	0.051584	-
10	On-peak kWh/mth	-	MWh	0.057461	-	0.058899	-
	Capacity						
11	Off-peak kWh/mth	-	MWh	0.025189	-	0.029067	-
12	On-peak kWh/mth	-	MWh	0.028345		0.033189	
	Provisions						
13	Education GEI	-	MWh		-	-	-
14	Total Winter Power Supply				-		-
15	Annual PSCR Factor kWh/mth	-	MWh	0.000800	-	0.000800	-
16	Total Power Supply				$ -		$ -
	Delivery						
17	Distribution kWh/mth	-	MWh	0.042598	$ -	0.043954	$ -
18	Skewing			0.000708		0.000753	
19	System Access	-	Bills	20.00	-	20.00	-
20	Provisions						
21	Education GEI	-	MWh	(0.000708)	-	(0.000753)	-
22	Total Delivery				$ -		$ -
23	Total GSTU				$ -		$ -

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION	Case No.: U-20134
Consumers Energy Company	Exhibit No.: A-16 (LMC-3)
Present and Proposed Revenue Detail	Schedule: F-3
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	Witness: LMCollins
Secondary Demand GSD	Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	Peak kW/mth	3,529	MW		$ -	8.15	$ 28,763
2	All kWh/mth	1,286,251	MWh	0.066606	85,672	0.043336	55,741
	Capacity						
3	Peak kW/mth	3,529	MW	12.17	$ 42,950	13.41	$ 47,326
4	All kWh/mth	1,286,251	MWh		-		-
	Provisions						
5	Education GEI	54,752	MWh		-	-	-
6	Total Summer Power Supply				128,622		131,830
	Winter (Oct. - May)						
	Non Capacity						
7	Peak kW/mth	6,437	MW		-	6.15	39,588
8	All kWh/mth	2,292,706	MWh	0.061437	140,857	0.041030	94,070
	Capacity						
9	Peak kW/mth	6,437	MW	10.17	65,465	11.41	73,447
10	All kWh/mth	2,292,706	MWh		-		-
	Provisions						
11	Education GEI	132,843	MWh		-	-	-
12	Total Winter Power Supply				206,322		207,104
13	Annual PSCR Factor kWh/mth	3,578,957	MWh	0.000800	2,863	0.000800	2,863
14	Annual Power Factor Adjustment				-		834
15	Total Power Supply				$ 337,807		$ 342,631
	Delivery						
16	Peak kW/mth	9,966	MW	1.15	$ 11,461	1.15	$ 11,461
17	Distribution kWh/mth	3,578,957	MWh	0.035114	125,671	0.031730	113,560
18	Skewing			0.000619		0.000621	
19	System Access	246,490	Bills	30.00	7,395	30.00	7,395
	Provisions						
20	Education GEI	187,595	MWh	(0.000619)	(116)	(0.000621)	(116)
21	Annual Power Factor Adjustment				137		137
22	Total Delivery				$ 144,548		$ 132,437
	ROA Service						
	Delivery						
23	Peak kW/mth	559	MW	1.15	$ 643	1.15	$ 643
24	Distribution kWh/mth	203,294	MWh	0.035114	7,138	0.031730	6,451
25	System Access	6,156	Bills	30.00	185	30.00	185
	Provisions						
26	Education GEI	62,955	MWh	(0.000619)	$ (39)	(0.000621)	(39)
27	Total Delivery				$ 7,927		$ 7,239
28	Total Secondary GSD				$ 490,282		$ 482,307
					$ 487,419		

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
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Date: May 2018

Primary Energy-only GP (Voltage Level 1)

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	
Line		**Billing Determinants**		**Present**			**Proposed**		
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**		**Rates**	**Revenue**	
				$/unit	$000		$/unit	$000	
	Bundled Service								
	Power Supply								
	Summer (June - Sept.)								
	Non Capacity								
1	All kWh/mth	2,624	MWh	0.051860	$	136	0.050042	$	131
2	Capacity								
3	All kWh/mth	2,624	MWh	0.033726	$	88	0.032192	$	84
	Provisions								
4	Education GEI	-	MWh	-		-	-		-
5	Total Summer Power Supply					225			216
	Winter (Oct. - May)								
	Non Capacity								
6	All kWh/mth	1,605	MWh	0.049761		80	0.049535		80
7	Capacity								
8	All kWh/mth	1,605	MWh	0.032361		52	0.031866		51
	Provisions								
9	Education GEI	-	MWh	-		-	-		-
10	Total Winter Power Supply					132			131
11	Annual PSCR Factor kWh/mth	4,229	MWh	0.000800		3	0.000800		3
12	Total Power Supply				$	360		$	350
	Delivery								
13	Distribution kWh/mth	4,229	MWh	0.007861	$	33	0.005784	$	24
14	Skewing			0.000530			0.000514		
15	Substation Ownership	491	MWh	(0.000393)		(0)	(0.000289)		(0)
16	System Access	63	Bills	100.00		6	100.00		6
	Provisions								
17	Education GEI	-	MWh	(0.000530)		-	(0.000514)		-
18	Total Delivery				$	39		$	31
	ROA Service								
	Delivery								
19	Distribution kWh/mth	-	MWh	0.007861	$	-	0.005784	$	-
20	Substation Ownership	-	MWh	(0.000393)		-	(0.000289)		-
21	System Access	-	Bills	100.00		-	100.00		-
	Provisions								
22	Education GEI	-	MWh	(0.000530)		-	(0.000514)		-
23	Total Delivery				$	-		$	-
24	Total Primary GP (Voltage Level 1)				$	399		$	380
								$	155,692

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Energy-only GP (Voltage Level 2)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	
		Billing Determinants		**Present**			**Proposed**		
Line No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**		**Rates**	**Revenue**	
				$/unit	$000		$/unit	$000	
	Bundled Service								
	Power Supply								
	Summer (June - Sept.)								
	Non Capacity								
1	All kWh/mth	29,515	MWh	0.053860	$	1,590	0.051132	$	1,509
	Capacity								
2	All kWh/mth	29,515	MWh	0.035726	$	1,054	0.033282	$	982
	Provisions								
3	Education GEI	-	MWh			-	-		-
4	Total Summer Power Supply					2,644			2,491
	Winter (Oct. - May)								
	Non Capacity								
5	All kWh/mth	58,155	MWh	0.051761		3,010	0.050625		2,944
	Capacity								
6	All kWh/mth	58,155	MWh	0.034361		1,998	0.032956		1,917
	Provisions								
7	Education GEI	-	MWh	-		-	-		-
8	Total Winter Power Supply					5,008			4,861
9	Annual PSCR Factor kWh/mth	87,670	MWh	0.000800		70	0.000800		70
10	Total Power Supply				$	7,723		$	7,422
	Delivery								
11	Distribution kWh/mth	87,670	MWh	0.010745	$	942	0.007784	$	682
12	Substation Ownership	8,644	MWh	(0.000393)		(3)	(0.000289)		(2)
13	System Access	650	Bills	100.00		65	100.00		65
	Provisions								
14	Education GEI	-	MWh	(0.000530)		-	(0.000514)		-
15	Total Delivery				$	1,004		$	745
	ROA Service								
	Delivery								
16	Distribution kWh/mth	2,845	MWh	0.010745	$	31	0.007784	$	22
17	Substation Ownership	-	MWh	(0.000393)		-	(0.000289)		-
18	System Access	28	Bills	100.00		3	100.00		3
	Provisions								
19	Education GEI	-	MWh	(0.000530)		-	(0.000514)		-
20	Total Delivery				$	33		$	25
21	Total Primary GP (Voltage Level 2)				$	8,760		$	8,192

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Energy-only GP (Voltage Level 3)

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Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Billing Determinants		**Present**		**Proposed**	
Line No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Bundled Service						
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	All kWh/mth	445,566	MWh	0.059560	$ 26,538	0.057042	$ 25,416
	Capacity						
2	All kWh/mth	445,566	MWh	0.041426	$ 18,458	0.039192	$ 17,463
	Provisions						
3	Education GEI	54,993	MWh	-	-	-	-
4	Total Summer Power Supply				44,996		42,879
	Winter (Oct. - May)						
	Non Capacity						
5	All kWh/mth	863,536	MWh	0.057461	49,620	0.056535	48,820
	Capacity						
6	All kWh/mth	863,536	MWh	0.040061	34,594	0.038866	33,562
	Provisions						
7	Education GEI	130,063	MWh	-	-	-	-
8	Total Winter Power Supply				84,214		82,382
9	Annual PSCR Factor kWh/mth	1,309,102	MWh	0.000800	1,047	0.000800	1,047
10	Total Power Supply				$ 130,257		$ 126,308
	Delivery						
11	Distribution kWh/mth	1,309,102	MWh	0.017201	$ 22,518	0.013698	$ 17,932
12	System Access	20,035	Bills	100.00	2,003	100.00	2,003
13	Provisions						
14	Education GEI	185,056	MWh	(0.000530)	(98)	(0.000514)	(95)
15	Total Delivery				$ 24,423		$ 19,840
	ROA Service						
	Delivery						
16	Distribution kWh/mth	67,745	MWh	0.017201	$ 1,165	0.013698	$ 928
17	System Access	555	Bills	100.00	55	100.00	55
	Provisions						
18	Education GEI	24,079	MWh	(0.000530)	(13)	(0.000514)	(12)
19	Total Delivery				$ 1,208		$ 971
20	Total Primary GP (Voltage Level 3)				$ 155,888		$ 147,120

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Demand GPD (Voltage Level 1)

Case No.: U-20134
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Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line		Billing Determinants			Present		Proposed	
No.	Description	Quantity	Quantity	Units	Rates	Revenue	Rates	Revenue
		Present	*Proposed*		$/unit	$000	$/unit	$000
	Bundled Service							
	Power Supply							
	Summer (June - Sept.)							
	Non Capacity							
1	On-peak kW/mth	1,714	1,264	MW	7.86	$ 13,469	7.78	$ 9,834
2	On-peak kWh/mth	284,074	263,741	MWh	0.046189	13,121	0.031439	8,292
3	Off-peak kWh/mth	947,402	882,337	MWh	0.030316	28,721	0.020376	17,979
	Capacity							
4	On-peak kW/mth	1,714	1,264	MW	10.52	18,028	14.85	$ 18,771
5	On Peak Transmission	1,714	1,264	MW	1.86	3,187	6.55	$ 8,279
	Provisions							
6	Interruptible GI	899	450	MW	(7.00)	(6,295)	(7.00)	(3,147)
7	Interr GI2 Cap & Trans		85,398	MWh			0.032914	2,811
8	Interr GI2 LMP		85,398	MWh			0.032270	2,756
9	Education GEI	18,455	18,455	MWh	-	-	-	-
10	Total Summer Power Supply					70,232		65,573
	Winter (Oct. - May)							
	Non Capacity							
11	On-peak kW/mth	3,476	3,032	MW	7.86	27,324	6.78	20,555
12	On-peak kWh/mth	541,305	500,639	MWh	0.036253	19,624	0.025664	12,848
13	Off-peak kWh/mth	1,766,743	1,636,612	MWh	0.032217	56,919	0.022477	36,786
	Capacity							
14	On-peak kW/mth	3,476	3,032	MW	9.52	33,094	13.85	41,989
15	On Peak Transmission	3,476	3,032	MW	1.86	6,466	6.55	19,857
	Provisions							
16	Interruptible GI	889	445	MW	(6.00)	(5,335)	(6.00)	(2,668)
17	Interr GI2 Cap & Trans		170,797	MWh			0.029295	5,003
18	Interr GI2 LMP		170,797	MWh			0.031100	5,312
19	Education GEI	25,715	25,715	MWh		-	-	-
20	Total Winter Power Supply					138,091		139,683
21	Annual PSCR Factor kWh/mth	3,539,524	3,283,329	MWh	0.000800	2,832	0.000800	2,627
22	Annual Power Factor Adjustment					(565)		(556)
23	Total Power Supply					$ 210,590		$ 207,328
	Delivery							
24	Maximum kW/mth	7,290	7,290	MW	1.06	$ 7,728	0.98	7,121
25	Skewing				0.135964		0.128228	
26	Substation Ownership	611	611	MW	(0.38)	(232)	(0.46)	(281)
27	Joint Substation Ownership	3,398	3,398	MW	(0.26)	(883)	(0.31)	(1,063)
28	System Access	407	407	Bills	200.00	81	200.00	81
29	Provisions							
	Education GEI	44,170	44,170	MWh	(0.000296)	(13)	(0.000314)	(14)
30	Annual Power Factor Adjustment					(18)		(16)
31	Total Delivery					$ 6,663		$ 5,829
	ROA Service							
	Delivery							
	Maximum kW/mth	2,073	2,073	MW	1.06	$ 2,198	0.98	$ 2,025
32	Substation Ownership	274	274	MW	(0.38)	(104)	(0.46)	(126)
33	System Access	178	178	Bills	200.00	36	200.00	36
34	Provisions							
	Education GEI	2,836	2,836	MWh	(0.000296)	(1)	(0.000314)	(1)
35	Total Delivery					$ 2,129		$ 1,934
36								
						$ 219,382		$ 215,090
37	Total Primary GPD (Voltage Level 1)							

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Demand GPD (Voltage Level 2)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 17 of 29
Witness: LMCollins
Date: May 2018

	(a)	(b)		(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**			**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
		Present	*Proposed*		$/unit	$000	$/unit	$000
	Bundled Service							
	Power Supply							
	Summer (June - Sept.)							
	Non Capacity							
1	On-peak kW/mth	1,405	1,237	MW	7.86	$ 11,042	8.78	$ 10,859
2	On-peak kWh/mth	200,117	189,408	MWh	0.048189	9,643	0.032529	6,161
3	Off-peak kWh/mth	568,134	533,865	MWh	0.032316	18,360	0.021466	11,460
	Capacity							
4	On-peak kW/mth	1,405	1,237	MW	11.52	$ 16,183	15.85	$ 19,604
5	On Peak Transmission	1,405	1,237	MW	1.86	$ 2,613	6.68	$ 8,262
	Provisions							
6	Interruptible GI	336	168	MW	(7.00)	(2,352)	(7.00)	(1,176)
7	Interr GI2 Cap & Trans		44,978	MWh			0.035317	1,588
8	Interr GI2 LMP		44,978	MWh			0.032270	1,451
9	Education GEI	19,035	19,035	MWh		-	-	-
10	Total Summer Power Supply					55,490		58,210
	Winter (Oct. - May)							
	Non Capacity							
11	On-peak kW/mth	2,855	2,573	MW	7.86	22,440	7.78	20,016
12	On-peak kWh/mth	399,618	378,199	MWh	0.038253	15,287	0.026754	10,118
13	Off-peak kWh/mth	1,152,455	1,083,917	MWh	0.034217	39,434	0.023567	25,545
	Capacity							
14	On-peak kW/mth	2,855	2,573	MW	10.52	30,035	14.85	38,206
15	On Peak Transmission	2,855	2,573		1.86	5,310	6.68	17,186
	Provisions							
16	Interruptible GI	564	282	MW	(6.00)	(3,387)	(6.00)	(1,693)
17	Interr GI2 Cap & Trans		89,956	MWh			0.031698	2,851
18	Interr GI2 LMP		89,956	MWh			0.031100	2,798
19	Education GEI	35,760	35,760	MWh		-	-	-
20	Total Winter Power Supply					109,119		115,027
21	Annual PSCR Factor kWh/mth	2,320,324	2,185,389	MWh	0.000800	1,856	0.000800	1,748
22	Annual Power Factor Adjustment					(172)		(180)
23	Total Power Supply					$ 166,293		$ 174,805
	Delivery							
24	Maximum kW/mth	5,164	5,164	MW	1.90	$ 9,812	1.93	$ 9,965
25	Substation Ownership	663	663	MW	(0.65)	(431)	(0.96)	(636)
26	System Access	1,358	1,358	Bills	200.00	272	200.00	272
	Provisions							
27	Education GEI	54,795	54,795	MWh	(0.000296)	(16)	(0.000314)	(17)
28	Annual Power Factor Adjustment					(10)		(10)
29	Total Delivery					$ 9,627		$ 9,574
	ROA Service							
	Delivery							
30	Maximum kW/mth	2,980	2,980	MW	1.90	$ 5,663	1.93	$ 5,751
31	Substation Ownership	542	542	MW	(0.65)	(352)	(0.96)	(520)
32	System Access	538	538	Bills	200.00	108	200.00	108
	Provisions							
33	Education GEI	75,246	75,246	MWh	(0.000296)	(22)	(0.000314)	(24)
34	Total Delivery					$ 5,396		$ 5,315
35	Total Primary GPD (Voltage Level 2)					$ 181,316		$ 189,695

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Demand GPD (Voltage Level 3)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

	(a)	(b)		(c)	(d)	(e)		(f)	(g)	
Line		Billing Determinants			Present			Proposed		
No.	Description	Quantity	Quantity	Units	Rates	Revenue		Rates	Revenue	
		Present	*Proposed*		$/unit	$000		$/unit	$000	
	Bundled Service									
	Power Supply									
	Summer (June - Sept.)									
	Non Capacity									
1	On-peak kW/mth	3,572	3,283	MW	7.86	$	28,078	9.78	$	32,107
2	On-peak kWh/mth	492,927	491,975	MWh	0.053889		26,563	0.038439	$	18,911
3	Off-peak kWh/mth	1,290,626	1,287,580	MWh	0.038016		49,064	0.027376	$	35,249
	Capacity									
4	On-peak kW/mth	3,572	3,283	MW	12.52	$	44,725	16.85	$	55,317
5	On Peak Transmission	3,572	3,283	MW	1.86	$	6,645	6.95	$	22,816
	Provisions									
6	Interruptible GI	579	289	MW	(7.00)		(4,052)	(7.00)	$	(2,026)
7	Interr GI2 Cap & Trans		3,999	MWh				0.047607	$	190
8	Interr GI2 LMP		3,999	MWh				0.032270	$	129
9	Education GEI	76,963	76,963	MWh			-	-		-
	Total Summer Power Supply						151,025			162,694
	Winter (Oct. - May)									
	Non Capacity									
10	On-peak kW/mth	6,607	6,024	MW	7.86		51,932	8.78	$	52,892
11	On-peak kWh/mth	905,476	903,572	MWh	0.043953		39,798	0.032664	$	29,514
12	Off-peak kWh/mth	2,389,721	2,383,628	MWh	0.039917		95,390	0.029477	$	70,262
	Capacity									
13	On-peak kW/mth	6,607	6,024	MW	11.52		76,114	15.85	$	95,482
14	On Peak Transmission	6,607	6,024	MW	1.86		12,289	6.95	$	41,867
	Provisions									
15	Interruptible GI	1,166	583	MW	(6.00)		(6,996)	(6.00)	$	(3,498)
16	Interr GI2 Cap & Trans		7,997	MWh				0.043987	$	352
17	Interr GI2 LMP		7,997	MWh				0.031100	$	249
18	Education GEI	176,415	176,415	MWh			-	-		-
19	Total Winter Power Supply						268,528			287,120
20	Annual PSCR Factor kWh/mth	5,078,750	5,066,754	MWh	0.000800		4,063	0.000800	$	4,063
21	Annual Power Factor Adjustment						(10)			(11)
22	Total Power Supply					$	423,605		$	453,866
	Delivery									
23	Maximum kW/mth	12,294	12,294	MW	4.21	$	51,758	3.80	$	46,667
24	System Access	18,673	18,673	Bills	200.00		3,735	200.00		3,735
25	Provisions									
26	Education GEI	253,378	253,378	MWh	(0.000296)		(75)	(0.000314)	$	(80)
27	Annual Power Factor Adjustment						(1)			(1)
28	Total Delivery					$	55,417		$	50,321
	ROA Service									
	Delivery									
29	Maximum kW/mth	2,993	2,993	MW	4.21	$	12,602	3.80	$	11,362
30	System Access	3,953	3,953	Bills	200.00		791	200.00		791
	Provisions									
31	Education GEI	151,985	151,985	MWh	(0.000296)		(45)	(0.000314)	$	(48)
32	Total Delivery					$	13,347		$	12,105
33	Total Primary GPD (Voltage Level 3)					$	492,369		$	516,292

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 19 of 29
Witness: LMCollins
Date: May 2018

General Service Primary Time-of-Use - GPTU (Voltage Level 1)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	High-/On-peak kWh/mth	42	MWh	0.085928	$ 4	0.083655	$ 4
2	Mid-peak kWh/mth	54	MWh	0.079838	4	0.073438	4
3	Low-peak kWh/mth	103	MWh	0.065472	7	0.059262	6
4	Off-peak kWh/mth	232	MWh	0.047986	11	0.044305	10
	Capacity						
5	High-/On-peak kWh/mth	42	MWh	0.021795	$ 1	0.029714	$ 1
6	Mid-peak kWh/mth	54	MWh	0.020250	1	0.026085	1
7	Low-peak kWh/mth	103	MWh	0.016606	2	0.021050	2
8	Off-peak kWh/mth	232	MWh	0.012171	3	0.015737	4
	Provisions						
9	Education GEI	-	MWh		-	-	-
10	Total Summer Power Supply				32		32
	Winter (Oct. - May)						
	Non Capacity						
11	High-/On-peak kWh/mth	100	MWh	0.057059	6	0.052588	5
12	Mid-peak kWh/mth	131	MWh	0.054191	7	0.051080	7
13	Off-peak kWh/mth	822	MWh	0.047349	39	0.044873	37
	Capacity						
14	High-/On-peak kWh/mth	100	MWh	0.014471	1	0.018680	2
15	Mid-peak kWh/mth	131	MWh	0.013744	2	0.018144	2
16	Off-peak kWh/mth	822	MWh	0.012009	10	0.015939	13
	Provisions						
17	Education GEI	-	MWh		-	-	-
18	Total Winter Power Supply				65		66
19	Annual PSCR Factor kWh/mth	1,485	MWh	0.000800	1	0.000800	1
20	Annual Power Factor Adjustment				(0)		(0)
21	Total Power Supply				$ 98		$ 99
	Delivery						
22	Maximum kW/mth	14	MW	1.06	$ 15	0.98	$ 14
23	Substation Ownership	-	MW	(0.38)	-	(0.46)	-
24	System Access	12	Bills	200.00	2	200.00	2
25	Annual Power Factor Adjustment				(0)		(0)
	Provisions						
26	Education GEI	-	MWh	(0.000296)	-	(0.000314)	-
27	Total Delivery				$ 17		$ 16
28	Total Primary GPTU (Voltage Level 1)				$ 115		$ 115

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

General Service Primary Time-of-Use - GPTU (Voltage Level 2)

	(a)	(b)	(c)	(d)		(e)	(f)		(g)
Line		**Billing Determinants**		**Present**			**Proposed**		
No.	**Description**	**Quantity**	**Units**	**Rates**		**Revenue**	**Rates**		**Revenue**
				$/unit		$000	$/unit		$000
	Power Supply	*Present*							
	Summer (June - Sept.)								
	Non Capacity								
1	High-/On-peak kWh/mth	3,871	MWh	0.087928	$	340	0.085655	$	332
2	Mid-peak kWh/mth	5,184	MWh	0.081838		424	0.075438		391
3	Low-peak kWh/mth	10,089	MWh	0.067472		681	0.061262		618
4	Off-peak kWh/mth	17,335	MWh	0.049986		866	0.046305		803
	Capacity								
5	High-/On-peak kWh/mth	3,871	MWh	0.023795	$	92	0.031714	$	123
6	Mid-peak kWh/mth	5,184	MWh	0.022250		115	0.028085		146
7	Low-peak kWh/mth	10,089	MWh	0.018606		188	0.023050		233
8	Off-peak kWh/mth	17,335	MWh	0.014171		246	0.017737		307
	Provisions								
9	Education GEI	-	MWh			-			-
10	Total Summer Power Supply					2,953			2,952
	Winter (Oct. - May)								
	Non Capacity								
11	High-/On-peak kWh/mth	4,322	MWh	0.059059	$	255	0.054588	$	236
12	Mid-peak kWh/mth	5,843	MWh	0.056191		328	0.053080		310
13	Off-peak kWh/mth	31,945	MWh	0.049349		1,576	0.046873		1,497
	Capacity								
14	High-/On-peak kWh/mth	4,322	MWh	0.016471	$	71	0.020680	$	89
15	Mid-peak kWh/mth	5,843	MWh	0.015744		92	0.020144		118
16	Off-peak kWh/mth	31,945	MWh	0.014009		448	0.017939		573
	Provisions								
17	Education GEI	-	MWh			-	-		-
18	Total Winter Power Supply					2,771			2,824
19	Annual PSCR Factor kWh/mth	78,587	MWh	0.000800		63	0.000800		63
20	Annual Power Factor Adjustment					(14)			(14)
21	Total Power Supply				$	5,773		$	5,824
	Delivery								
22	Maximum kW/mth	194	MW	1.90	$	369	1.93	$	375
23	Substation Ownership	171	MW	(0.65)		(111)	(0.96)		(164)
24	System Access	192	Bills	200.00		38	200.00		38
	Provisions								
25	Education GEI	-	MWh	(0.000296)		-	(0.000314)		-
26	Annual Power Factor Adjustment					(1)			(1)
27	Total Delivery				$	296		$	249
28	Total Primary GPTU (Voltage Level 2)				$	6,069		$	6,074

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 21 of 29
Witness: LMCollins
Date: May 2018

General Service Primary Time-of-Use - GPTU (Voltage Level 3)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Power Supply	Present					
	Summer (June - Sept.)						
	Non Capacity						
1	High-/On-peak kWh/mth	27,332	MWh	0.093628	$ 2,559	0.090655	$ 2,478
2	Mid-peak kWh/mth	36,421	MWh	0.087538	3,188	0.080438	2,930
3	Low-peak kWh/mth	71,569	MWh	0.073172	5,237	0.066262	4,742
4	Off-peak kWh/mth	122,660	MWh	0.055686	6,830	0.051305	6,293
	Capacity						
5	High-/On-peak kWh/mth	27,332	MWh	0.029495	$ 806	0.036714	$ 1,003
6	Mid-peak kWh/mth	36,421	MWh	0.027950	1,018	0.033085	1,205
7	Low-peak kWh/mth	71,569	MWh	0.024306	1,740	0.028050	2,008
8	Off-peak kWh/mth	122,660	MWh	0.019871	2,437	0.022737	2,789
	Provisions						
9	Education GEI	-	MWh		$ -		$ -
10	Total Summer Power Supply				23,816		23,448
	Winter (Oct. - May)						
	Non Capacity						
11	High-/On-peak kWh/mth	32,281	MWh	0.064759	$ 2,090	0.059588	$ 1,924
12	Mid-peak kWh/mth	44,009	MWh	0.061891	2,724	0.058080	2,556
13	Off-peak kWh/mth	249,835	MWh	0.055049	13,753	0.051873	12,960
	Capacity						
14	High-/On-peak kWh/mth	32,281	MWh	0.022171	$ 716	0.025680	$ 829
15	Mid-peak kWh/mth	44,009	MWh	0.021444	944	0.025144	1,107
16	Off-peak kWh/mth	249,835	MWh	0.019709	4,924	0.022939	5,731
	Provisions						
17	Education GEI	-	MWh		$ -	-	$ -
18	Total Winter Power Supply				25,151		25,106
19	Annual PSCR Factor kWh/mth	584,106	MWh	0.000800	467	0.000800	467
20	Annual Power Factor Adjustment				88		88
21	Total Power Supply				$ 49,522		$ 49,108
	Delivery						
22	Maximum kW/mth	1,605	MW	4.21	$ 6,758	3.80	$ 6,094
23	System Access	3,324	Bills	200.00	665	200.00	665
	Provisions						
24	Education GEI	-	MWh	(0.000296)	-	(0.000314)	-
25	Annual Power Factor Adjustment				12		11
26	Total Delivery				$ 7,435		$ 6,769
27	Total Primary GPTU (Voltage Level 3)				$ 56,957		$ 55,878

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Energy Intensive Rate (Voltage Level 1)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 22 of 29
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	Critical-peak kWh/mth	543	MWh	0.083495	$ 45	0.136532	$ 74
2	High-peak kWh/mth	7,621	MWh	0.055663	424	0.091021	694
3	Mid-peak kWh/mth	8,403	MWh	0.051879	436	0.084536	710
4	Low-peak kWh/mth	40,811	MWh	0.042573	1,737	0.067976	2,774
5	Off-peak kWh/mth	52,518	MWh	0.031246	1,641	0.048003	2,521
	Capacity						
6	Critical-peak kWh/mth	543	MWh	0.041921	$ 23	0.002501	$ 1
7	High-peak kWh/mth	7,621	MWh	0.027947	213	0.001667	13
8	Mid-peak kWh/mth	8,403	MWh	0.026047	219	0.001548	13
9	Low-peak kWh/mth	40,811	MWh	0.021375	872	0.001245	51
10	Off-peak kWh/mth	52,518	MWh	0.015688	824	0.000879	46
11	Total Summer Power Supply				$ 6,435		$ 6,897
	Winter (Oct. - May)						
	Non Capacity						
12	Critical-peak kWh/mth	190	MWh	0.078156	$ 15	0.130857	$ 25
13	High-peak kWh/mth	13,457	MWh	0.052104	701	0.087238	1,174
14	Mid-peak kWh/mth	13,459	MWh	0.041744	562	0.068667	924
15	Off-peak kWh/mth	154,456	MWh	0.032309	4,990	0.048262	7,454
	Capacity						
16	Critical-peak kWh/mth	190	MWh	0.039240	$ 7	0.002397	$ 0
17	High-peak kWh/mth	13,457	MWh	0.026160	352	0.001598	22
18	Mid-peak kWh/mth	13,459	MWh	0.020959	282	0.001258	17
19	Off-peak kWh/mth	154,456	MWh	0.016222	2,506	0.000884	137
20	Total Winter Power Supply				$ 9,415		$ 9,753
21	Annual Power Factor Adjustment				$ (36)		$ (36)
22	Annual PSCR Factor kWh/mth	291,458	MWh	0.000800	233	0.000800	233
23	Total Power Supply				$16,083		$ 16,847
	Delivery						
24	Maximum kW/mth	1,172	MW	1.06	$ 1,242	0.98	$ 1,145
25	Skewing			0.000273			
26	Substation Ownership	2,546	MW	(0.38)	(968)	(0.46)	(1,171)
27	System Access	63	Bills	200.00	13	200.00	13
28	Annual Power Factor Adjustment				(3)		(0)
29	Total Delivery				$ 285		$ (14)
30	Total Primary EIP (Voltage Level 1)				$16,368		$ 16,833

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Energy Intensive Rate (Voltage Level 2)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 23 of 29
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		Billing Determinants		Present		Proposed	
No.	Description	Quantity	Units	Rates	Revenue	Rates	Revenue
				$/unit	$000	$/unit	$000
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	Critical-peak kWh/mth	60	MWh	0.085495	$ 5	0.141532	$ 9
2	High-peak kWh/mth	1,293	MWh	0.057663	75	0.096021	124
3	Mid-peak kWh/mth	1,309	MWh	0.053879	71	0.089536	117
4	Low-peak kWh/mth	7,820	MWh	0.044573	349	0.072976	571
5	Off-peak kWh/mth	16,148	MWh	0.033246	537	0.053003	856
	Capacity						
6	Critical-peak kWh/mth	60	MWh	0.044921	$ 3	0.007501	$ 0
7	High-peak kWh/mth	1,293	MWh	0.030947	40	0.006667	9
8	Mid-peak kWh/mth	1,309	MWh	0.029047	38	0.006548	9
9	Low-peak kWh/mth	7,820	MWh	0.024375	191	0.006245	49
10	Off-peak kWh/mth	16,148	MWh	0.018688	302	0.005879	95
11	Total Summer Power Supply				$ 1,609		$ 1,838
	Winter (Oct. - May)						
	Non Capacity						
12	Critical-peak kWh/mth	28	MWh	0.080156	$ 2	0.135857	$ 4
13	High-peak kWh/mth	2,011	MWh	0.054104	109	0.092238	186
14	Mid-peak kWh/mth	2,117	MWh	0.043744	93	0.073667	156
15	Off-peak kWh/mth	45,210	MWh	0.034309	1,551	0.053262	2,408
	Capacity						
16	Critical-peak kWh/mth	28	MWh	0.042240	$ 1	0.007397	$ 0
17	High-peak kWh/mth	2,011	MWh	0.029160	59	0.006598	13
18	Mid-peak kWh/mth	2,117	MWh	0.023959	51	0.006258	13
19	Off-peak kWh/mth	45,210	MWh	0.019222	869	0.005884	266
20	Total Winter Power Supply				2,734		3,046
21	Annual Power Factor Adjustment				(14)		(22)
22	Annual PSCR Factor kWh/mth	75,997	MWh	0.000800	$ 61	0.000800	$ 61
23	Total Power Supply				$ 4,404		$ 4,922
	Delivery						
24	Maximum kW/mth	411	MW	1.90	$ 780	1.93	$ 792
25	Substation Ownership	1,172	MW	(0.65)	(762)	(0.96)	(1,125)
26	System Access	88	Bills	200.00	18	200.00	18
27	Annual Power Factor Adjustment				(4)		1
28	Total Delivery				$ 32		$ (314)
29	Total Primary EIP (Voltage Level 2)				$ 4,436		$ 4,608

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Primary Energy Intensive Rate (Voltage Level 3)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Power Supply						
	Summer (June - Sept.)						
	Non Capacity						
1	Critical-peak kWh/mth	13	MWh	0.091195	$ 1	0.138532	$ 2
2	High-peak kWh/mth	206	MWh	0.063363	13	0.093021	19
3	Mid-peak kWh/mth	233	MWh	0.059579	14	0.086536	20
4	Low-peak kWh/mth	2,309	MWh	0.050273	116	0.069976	162
5	Off-peak kWh/mth	2,768	MWh	0.038946	108	0.050003	138
	Capacity						
6	Critical-peak kWh/mth	13	MWh	0.033921	$ 0	0.004501	$ 0
7	High-peak kWh/mth	206	MWh	0.019947	4	0.003667	1
8	Mid-peak kWh/mth	233	MWh	0.018047	4	0.003548	1
9	Low-peak kWh/mth	2,309	MWh	0.013375	31	0.003245	7
10	Off-peak kWh/mth	2,768	MWh	0.007688	21	0.002879	8
11	Total Summer Power Supply				$ 313		$ 358
	Winter (Oct. - May)						
	Non Capacity						
12	Critical-peak kWh/mth	4	MWh	0.085856	$ 0	0.132857	$ 1
13	High-peak kWh/mth	182	MWh	0.059804	11	0.089238	16
14	Mid-peak kWh/mth	227	MWh	0.049444	11	0.070667	16
15	Off-peak kWh/mth	9,686	MWh	0.040009	388	0.050262	487
	Capacity						
16	Critical-peak kWh/mth	4	MWh	0.031240	$ 0	0.004397	$ 0
17	High-peak kWh/mth	182	MWh	0.018160	3	0.003598	1
18	Mid-peak kWh/mth	227	MWh	0.012959	3	0.003258	1
19	Off-peak kWh/mth	9,686	MWh	0.008222	80	0.002884	28
20	Total Winter Power Supply				$ 496		$ 549
21	Annual Power Factor Adjustment				$ (4)		$ (4)
22	Annual PSCR Factor kWh/mth	15,628	MWh	0.000800	13	0.000800	13
23	Total Power Supply				$ 821		$ 916
	Delivery						
24	Maximum kW/mth	98	MW	4.21	$ 413	3.80	$ 373
25	System Access	76	Bills	200.00	15	200.00	15
26	Annual Power Factor Adjustment				(2)		(2)
27	Total Delivery				$ 427		$ 386
28	Total Primary EIP (Voltage Level 3)				$ 1,248		$ 1,302

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Large Self-generation GSG-2

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 25 of 29
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Power Supply						
	Primary						
	On Peak Capacity						
1	Voltage Level 1	61	MW		$ 1,246		
2	Voltage Level 2	98	MW		292		
3	Voltage Level 3	2	MW		10		
	Delivery						
	Standby kW/mth						
4	Voltage Level 1	1,475	MW	1.06	$ 1,564	0.98	$ 1,441
5	Voltage Level 2	345	MW	1.90	656	1.93	$ 666
6	Voltage Level 3	12	MW	4.21	50	3.80	$ 45
	Substation Ownership						
7	Voltage Level 1	(96)	MW	(0.38)	36	(0.46)	$ 44
8	Voltage Level 2	295	MW	(0.65)	(192)	(0.96)	$ (284)
9	Transmission Interconnect	96	MW	(1.06)	(102)	(0.98)	$ (94)
	Standby Option						
10	System Access	120	Bills	200.00	24	200.00	24
	Supplement Option [1]						
11	System Access	-	Bills	100.00	-	100.00	-
12	Total Delivery				$ 2,036		$ 1,842

Notes

[1] For customers who generate a portion of their load requirements, but take the majority of their power from Consumers Energy.

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Metered Lighting Service GML

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 26 of 29
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Power Supply						
	Secondary Service						
	Non Capacity						
1	All kWh/mth	14,284	MWh	0.050986	$ 728	0.070483	$ 1,007
	Primary Service						
	Non Capacity						
2	All kWh/mth	705	MWh	0.025022	18	0.034590	24
3	Annual PSCR Factor kWh/mth	14,989	MWh	0.000800	12	0.000800	12
4	Total Power Supply				$ 758		$ 1,043
	Delivery						
	Secondary Service						
5	Distribution kWh/mth	14,284	MWh	0.065052	$ 929	0.064457	$ 921
6	System Access	3,216	Bills	10.00	32	10.00	32
	Primary Service						
7	Distribution kWh/mth	705	MWh	0.049217	35	0.049108	35
8	System Access	48	Bills	20.00	1	20.00	1
9	Total Delivery				$ 997		$ 988
10	Total Metered Lighting GML				$ 1,755		$ 2,032

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Unmetered Lighting Service GUL

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(l)	(m)
		Billing Determinants					Present			Proposed		
							Rates			Rates		
Line No.	Description	Customer Fixtures	Company Fixtures	Units	Watts Incl Ballast	Total MWh Annual	Non Cap Service	Fixture	Revenue	Non Cap Service	Fixture	Revenue
							$/unit	$/unit	$000	$/unit	$/unit	$000
	Mercury Vapor											
1	3500 Lumens	-	3,860	Lights	128	173	7.71	6.00	$ 53	8.94	6.00	$ 58
2	7500 Lumens	36	119,452	Lights	209	8,741	12.59	6.00	2,221	14.60	6.00	2,461
3	10000 Lumens	432	24,064	Lights	281	2,409	16.93	6.00	559	19.63	6.00	625
4	20000 Lumens	828	19,056	Lights	458	3,187	27.59	6.00	663	31.99	6.00	750
5	35000 Lumens	-	-	Lights	770	-	46.39	6.00	-	53.78	6.00	-
6	50000 Lumens	-	20	Lights	1,080	8	65.07	6.00	1	75.43	6.00	2
7	Total Mercury Vapor	1,296	166,452			-			3,497			3,896
	High-Pressure Sodium					-						
8	5000 Lumens	72	2,428	Lights	83	73	5.00	6.00	27	5.80	6.00	29
9	8500 Lumens	804	1,419,304	Lights	117	58,153	7.05	6.00	18,528	8.17	6.00	20,120
10	14000 Lumens	1,404	210,547	Lights	171	12,685	10.30	6.00	3,446	11.94	6.00	3,795
11	20000 Lumens	60	15,132	Lights	247	1,313	14.88	6.00	317	17.25	6.00	353
12	24000 Lumens	540	172,644	Lights	318	19,275	19.16	6.00	4,354	22.21	6.00	4,882
13	45000 Lumens	180	79,509	Lights	480	13,388	28.92	6.00	2,782	33.52	6.00	3,149
14	Total HP Sodium	3,060	1,899,564			-			29,454			32,327
	Incandescent					-						
15	2500 Lumens	-	540	Lights	202	38	12.17	6.00	10	14.11	6.00	11
16	4000 Lumens	108	-	Lights	305	12	18.37	6.00	2	21.30	6.00	2
17	6000 Lumens	24	2,352	Lights	405	337	24.40	6.00	72	28.29	6.00	81
18	10000 Lumens	-	12	Lights	690	3	41.57	6.00	1	48.19	6.00	1
19	Total Incandescent	132	2,904			-			84			95
	Fluorescent					-						
20	20000 Lumens	-	252	Lights	470	41	28.32	6.00	9	32.83	6.00	10
	Metal Halide					-						
21	9750 Lumens	468	660	Lights	170	67	10.24	6.00	16	11.87	6.00	17
22	10500 Lumens	-	5,556	Lights	210	408	12.65	6.00	104	14.67	6.00	115
23	15500 Lumens	12	1,920	Lights	290	196	17.47	6.00	45	20.25	6.00	51
24	24000 Lumens	24	876	Lights	460	145	27.71	6.00	30	32.13	6.00	34
25	Total Metal Halide	504	9,012						195			217
26	Annual PSCR Factor kWh/mth		120,653	MWh				0.000800	97		0.000800	97
27	Total Unmetered Lighting GUL								$ 33,335			$ 36,642

		Present U-18322		Proposed	
	Classification	Customer	Company	Customer	Company
28	Power Supply (%)	29.7	18.0	34.2	22.5
29	Delivery (%)	70.3	82.0	65.8	77.5

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3
Page: 28 of 29
Witness: LMCollins
Date: May 2018

Unmetered Experimental Lighting Service GU-XL

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
				$/unit	$000	$/unit	$000
	Power Supply						
	Non Capacity						
1	All kWh/mth	14	MWh	0.059553	$ 0.820	0.047477	$ 1
2	Annual PSCR Factor kWh/mth	14	MWh	0.000800	0	0.000800	0
3	Total Power Supply				$ 1		$ 1
	Delivery						
	Customer Owned Equipment						
4	Distribution kWh/mth	10	MWh	0.025336	$ 0	0.117741	$ 1
	Company Owned Equipment						
5	Distribution kWh/mth	4	MWh	0.031076	0	0.144416	1
6	Fixture Charge/mth	119	Light	6.00	1	6.00	1
7	Total Delivery				$ 1		$ 2
8	Total Unmetered Service GU-XL				$ 2		$ 3

Notes

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
($000)

Case No.: U-20134
Exhibit No.: A-16 (LMC-3)
Schedule: F-3

Witness: LMCollins
Date: May 2018

Unmetered Service GU

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	
Line		**Billing Determinants**		**Present**			**Proposed**		
No.	**Description**	**Quantity**	**Units**	**Rates**	**Revenue**		**Rates**	**Revenue**	
				$/unit	$000		$/unit	$000	
	Power Supply								
	Non Capacity								
1	All kWh/mth	90,900	MWh	0.056376	$	5,125	0.051009	$	4,637
	Capacity								
2	All kWh/mth	90,900	MWh	0.018011	$	1,637	0.020081	$	1,825
3	Annual PSCR Factor kWh/mth	90,900	MWh	0.000800		73	0.000800		73
4	Total Power Supply				$	6,835		$	6,535
	Delivery								
5	Distribution kWh/mth	90,900	MWh	0.017001	$	1,545	0.017130	$	1,557
6	System Access	5,592	Bills	2.00		11	2.00		11
7	Total Delivery				$	1,557		$	1,568
8	Total Unmetered Service GU				$	8,391		$	8,103

Notes

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Service RS Summer On Peak Basic Rate
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	7.73	8.28	0.55	7.1	165.6	7.73	8.24	0.51	6.6	164.8
2	50	14.28	15.29	1.01	7.0	30.6	14.28	14.91	0.63	4.4	29.8
3	100	21.56	23.07	1.51	7.0	23.1	21.56	22.33	0.77	3.6	22.3
4	150	28.84	30.86	2.02	7.0	20.6	28.84	29.74	0.90	3.1	19.8
5	200	36.12	38.65	2.52	7.0	19.3	36.12	37.16	1.03	2.9	18.6
6	250	43.41	46.43	3.03	7.0	18.6	43.41	44.57	1.16	2.7	17.8
7	300	50.69	54.22	3.53	7.0	18.1	50.69	51.98	1.30	2.6	17.3
8	350	57.97	62.01	4.04	7.0	17.7	57.97	59.40	1.43	2.5	17.0
9	400	65.25	69.80	4.55	7.0	17.4	65.25	66.81	1.56	2.4	16.7
10	450	72.53	77.58	5.05	7.0	17.2	72.53	74.23	1.70	2.3	16.5
11	500	79.81	85.37	5.56	7.0	17.1	79.81	81.64	1.83	2.3	16.3
12	550	87.09	93.16	6.06	7.0	16.9	87.09	89.05	1.96	2.3	16.2
13	600	94.37	100.94	6.57	7.0	16.8	94.37	96.47	2.09	2.2	16.1
14	650	103.29	108.73	5.44	5.3	16.7	101.65	103.88	2.23	2.2	16.0
15	700	112.21	116.52	4.31	3.8	16.6	108.94	111.30	2.36	2.2	15.9
16	750	121.12	124.30	3.18	2.6	16.6	116.22	118.71	2.49	2.1	15.8
17	800	130.04	132.09	2.05	1.6	16.5	123.50	126.12	2.63	2.1	15.8
18	850	138.96	139.88	0.92	0.7	16.5	130.78	133.54	2.76	2.1	15.7
19	900	147.87	147.66	(0.21)	(0.1)	16.4	138.06	140.95	2.89	2.1	15.7
20	950	156.79	155.45	(1.34)	(0.9)	16.4	145.34	148.37	3.02	2.1	15.6
21	1,000	165.71	163.24	(2.47)	(1.5)	16.3	152.62	155.78	3.16	2.1	15.6
22	1,500	254.87	241.11	(13.77)	(5.4)	16.1	225.43	229.92	4.49	2.0	15.3
23	2,000	344.04	318.98	(25.06)	(7.3)	15.9	298.24	304.06	5.81	1.9	15.2
24	2,500	433.20	396.84	(36.36)	(8.4)	15.9	371.06	378.20	7.14	1.9	15.1
25	3,000	522.37	474.71	(47.66)	(9.1)	15.8	443.87	452.34	8.47	1.9	15.1
26	3,500	611.54	552.58	(58.95)	(9.6)	15.8	516.68	526.48	9.80	1.9	15.0
27	4,000	700.70	630.45	(70.25)	(10.0)	15.8	589.49	600.62	11.13	1.9	15.0
28	4,500	789.87	708.32	(81.55)	(10.3)	15.7	662.30	674.76	12.46	1.9	15.0
29	5,000	879.03	786.19	(92.85)	(10.6)	15.7	735.11	748.90	13.79	1.9	15.0

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
First 600 kWh/mth	0.094525		0.094525	
Excess kWh/mth	0.127235		0.094525	
On Peak kWh/mth		0.146791		0.098827
All Else kWh/mth		0.098827		0.098827
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	7.00	7.50	7.00	7.50

RS Summer On Peak Load Profile	
On Peak	16%
All Else	84%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Service RS Summer On Peak Basic Rate
Senior Citizen Provision RSC
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Increase Amount**	**Increase Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Increase Amount**	**Increase Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	4.23	4.53	0.30	7.1	90.6	4.23	4.49	0.26	6.2	89.8
2	50	10.78	11.54	0.76	7.0	23.1	10.78	11.16	0.38	3.6	22.3
3	100	18.06	19.32	1.26	7.0	19.3	18.06	18.58	0.52	2.9	18.6
4	150	25.34	27.11	1.77	7.0	18.1	25.34	25.99	0.65	2.6	17.3
5	200	32.62	34.90	2.27	7.0	17.4	32.62	33.41	0.78	2.4	16.7
6	250	39.91	42.68	2.78	7.0	17.1	39.91	40.82	0.91	2.3	16.3
7	300	47.19	50.47	3.28	7.0	16.8	47.19	48.23	1.05	2.2	16.1
8	350	54.47	58.26	3.79	7.0	16.6	54.47	55.65	1.18	2.2	15.9
9	400	61.75	66.05	4.30	7.0	16.5	61.75	63.06	1.31	2.1	15.8
10	450	69.03	73.83	4.80	7.0	16.4	69.03	70.48	1.45	2.1	15.7
11	500	76.31	81.62	5.31	7.0	16.3	76.31	77.89	1.58	2.1	15.6
12	550	83.59	89.41	5.81	7.0	16.3	83.59	85.30	1.71	2.0	15.5
13	600	90.87	97.19	6.32	7.0	16.2	90.87	92.72	1.84	2.0	15.5
14	650	99.79	104.98	5.19	5.2	16.2	98.15	100.13	1.98	2.0	15.4
15	700	108.71	112.77	4.06	3.7	16.1	105.44	107.55	2.11	2.0	15.4
16	750	117.62	120.55	2.93	2.5	16.1	112.72	114.96	2.24	2.0	15.3
17	800	126.54	128.34	1.80	1.4	16.0	120.00	122.37	2.38	2.0	15.3
18	850	135.46	136.13	0.67	0.5	16.0	127.28	129.79	2.51	2.0	15.3
19	900	144.37	143.91	(0.46)	(0.3)	16.0	134.56	137.20	2.64	2.0	15.2
20	950	153.29	151.70	(1.59)	(1.0)	16.0	141.84	144.62	2.77	2.0	15.2
21	1,000	162.21	159.49	(2.72)	(1.7)	15.9	149.12	152.03	2.91	1.9	15.2
22	1,500	251.37	237.36	(14.02)	(5.6)	15.8	221.93	226.17	4.24	1.9	15.1
23	2,000	340.54	315.23	(25.31)	(7.4)	15.8	294.74	300.31	5.56	1.9	15.0
24	2,500	429.70	393.09	(36.61)	(8.5)	15.7	367.56	374.45	6.89	1.9	15.0
25	3,000	518.87	470.96	(47.91)	(9.2)	15.7	440.37	448.59	8.22	1.9	15.0
26	3,500	608.04	548.83	(59.20)	(9.7)	15.7	513.18	522.73	9.55	1.9	14.9
27	4,000	697.20	626.70	(70.50)	(10.1)	15.7	585.99	596.87	10.88	1.9	14.9
28	4,500	786.37	704.57	(81.80)	(10.4)	15.7	658.80	671.01	12.21	1.9	14.9
29	5,000	875.53	782.44	(93.10)	(10.6)	15.6	731.61	745.15	13.54	1.9	14.9

	Summer Present	Summer Proposed	Winter Present	Winter Proposed
Power Supply Charges				
First 600 kWh/mth	0.094525		0.094525	
Excess kWh/mth	0.127235		0.094525	
On Peak kWh/mth		0.146791		0.098827
All Else kWh/mth		0.098827		0.098827
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	3.50	3.75	3.50	3.75

RS Summer On Peak Load Profile	
On Peak	16%
All Else	84%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION	Case No.: U-20134
Consumers Energy Company	Exhibit No.: A-16 (LMC-4)
Comparison of Present and Proposed Monthly Bills	Schedule: F-4
	Page: 3 of 53
Residential Service RS Summer On Peak Basic Rate	Witness: LMCollins
Income Assistance Provision RIA	Date: May 2018
Bundled Service	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	4.23	4.53	0.30	7.1	90.6	4.23	4.49	0.26	6.2	89.8
2	50	10.78	11.54	0.76	7.0	23.1	10.78	11.16	0.38	3.6	22.3
3	100	18.06	19.32	1.26	7.0	19.3	18.06	18.58	0.52	2.9	18.6
4	150	25.34	27.11	1.77	7.0	18.1	25.34	25.99	0.65	2.6	17.3
5	200	32.62	34.90	2.27	7.0	17.4	32.62	33.41	0.78	2.4	16.7
6	250	39.91	42.68	2.78	7.0	17.1	39.91	40.82	0.91	2.3	16.3
7	300	47.19	50.47	3.28	7.0	16.8	47.19	48.23	1.05	2.2	16.1
8	350	54.47	58.26	3.79	7.0	16.6	54.47	55.65	1.18	2.2	15.9
9	400	61.75	66.05	4.30	7.0	16.5	61.75	63.06	1.31	2.1	15.8
10	450	69.03	73.83	4.80	7.0	16.4	69.03	70.48	1.45	2.1	15.7
11	500	76.31	81.62	5.31	7.0	16.3	76.31	77.89	1.58	2.1	15.6
12	550	83.59	89.41	5.81	7.0	16.3	83.59	85.30	1.71	2.0	15.5
13	600	90.87	97.19	6.32	7.0	16.2	90.87	92.72	1.84	2.0	15.5
14	650	99.79	104.98	5.19	5.2	16.2	98.15	100.13	1.98	2.0	15.4
15	700	108.71	112.77	4.06	3.7	16.1	105.44	107.55	2.11	2.0	15.4
16	750	117.62	120.55	2.93	2.5	16.1	112.72	114.96	2.24	2.0	15.3
17	800	126.54	128.34	1.80	1.4	16.0	120.00	122.37	2.38	2.0	15.3
18	850	135.46	136.13	0.67	0.5	16.0	127.28	129.79	2.51	2.0	15.3
19	900	144.37	143.91	(0.46)	(0.3)	16.0	134.56	137.20	2.64	2.0	15.2
20	950	153.29	151.70	(1.59)	(1.0)	16.0	141.84	144.62	2.77	2.0	15.2
21	1,000	162.21	159.49	(2.72)	(1.7)	15.9	149.12	152.03	2.91	1.9	15.2
22	1,500	251.37	237.36	(14.02)	(5.6)	15.8	221.93	226.17	4.24	1.9	15.1
23	2,000	340.54	315.23	(25.31)	(7.4)	15.8	294.74	300.31	5.56	1.9	15.0
24	2,500	429.70	393.09	(36.61)	(8.5)	15.7	367.56	374.45	6.89	1.9	15.0
25	3,000	518.87	470.96	(47.91)	(9.2)	15.7	440.37	448.59	8.22	1.9	15.0
26	3,500	608.04	548.83	(59.20)	(9.7)	15.7	513.18	522.73	9.55	1.9	14.9
27	4,000	697.20	626.70	(70.50)	(10.1)	15.7	585.99	596.87	10.88	1.9	14.9
28	4,500	786.37	704.57	(81.80)	(10.4)	15.7	658.80	671.01	12.21	1.9	14.9
29	5,000	875.53	782.44	(93.10)	(10.6)	15.6	731.61	745.15	13.54	1.9	14.9

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
First 600 kWh/mth	0.094525		0.094525	
Excess kWh/mth	0.127235		0.094525	
On Peak kWh/mth		0.146791		0.098827
All Else kWh/mth		0.098827		0.098827
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	3.50	3.75	3.50	3.75

RS Summer On Peak Load Profile	
On Peak	16%
All Else	84%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Service RS AMI Opt Out
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 4 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	7.73	8.24	0.51	6.6	164.7	7.73	8.24	0.51	6.6	164.7
2	50	14.28	14.86	0.58	4.0	29.7	14.28	14.86	0.58	4.0	29.7
3	100	21.56	22.21	0.65	3.0	22.2	21.56	22.21	0.65	3.0	22.2
4	150	28.84	29.57	0.73	2.5	19.7	28.84	29.57	0.73	2.5	19.7
5	200	36.12	36.93	0.80	2.2	18.5	36.12	36.93	0.80	2.2	18.5
6	250	43.41	44.28	0.88	2.0	17.7	43.41	44.28	0.88	2.0	17.7
7	300	50.69	51.64	0.95	1.9	17.2	50.69	51.64	0.95	1.9	17.2
8	350	57.97	59.00	1.03	1.8	16.9	57.97	59.00	1.03	1.8	16.9
9	400	65.25	66.35	1.11	1.7	16.6	65.25	66.35	1.11	1.7	16.6
10	450	72.53	73.71	1.18	1.6	16.4	72.53	73.71	1.18	1.6	16.4
11	500	79.81	81.07	1.26	1.6	16.2	79.81	81.07	1.26	1.6	16.2
12	550	87.09	88.42	1.33	1.5	16.1	87.09	88.42	1.33	1.5	16.1
13	600	94.37	95.78	1.41	1.5	16.0	94.37	95.78	1.41	1.5	16.0
14	650	103.29	104.71	1.42	1.4	16.1	101.65	103.14	1.48	1.5	15.9
15	700	112.21	113.64	1.44	1.3	16.2	108.94	110.49	1.56	1.4	15.8
16	750	121.12	122.58	1.45	1.2	16.3	116.22	117.85	1.63	1.4	15.7
17	800	130.04	131.51	1.47	1.1	16.4	123.50	125.21	1.71	1.4	15.7
18	850	138.96	140.44	1.48	1.1	16.5	130.78	132.56	1.79	1.4	15.6
19	900	147.87	149.37	1.50	1.0	16.6	138.06	139.92	1.86	1.3	15.5
20	950	156.79	158.30	1.51	1.0	16.7	145.34	147.28	1.94	1.3	15.5
21	1,000	165.71	167.24	1.53	0.9	16.7	152.62	154.64	2.01	1.3	15.5
22	1,500	254.87	256.55	1.68	0.7	17.1	225.43	228.20	2.77	1.2	15.2
23	2,000	344.04	345.87	1.83	0.5	17.3	298.24	301.77	3.53	1.2	15.1
24	2,500	433.20	435.19	1.98	0.5	17.4	371.06	375.34	4.28	1.2	15.0
25	3,000	522.37	524.51	2.14	0.4	17.5	443.87	448.91	5.04	1.1	15.0
26	3,500	611.54	613.82	2.29	0.4	17.5	516.68	522.47	5.80	1.1	14.9
27	4,000	700.70	703.14	2.44	0.3	17.6	589.49	596.04	6.55	1.1	14.9
28	4,500	789.87	792.46	2.59	0.3	17.6	662.30	669.61	7.31	1.1	14.9
29	5,000	879.03	881.78	2.74	0.3	17.6	735.11	743.18	8.07	1.1	14.9

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
First 600 kWh/mth	0.094525	0.097683	0.094525	0.097683
Excess kWh/mth	0.127235	0.129183	0.094525	0.097683
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	7.00	7.50	7.00	7.50

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

Residential Service RS AMI Opt Out
Senior Citizen Provision RSC
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	4.23	4.49	0.26	6.1	89.7	4.23	4.49	0.26	6.1	89.7
2	50	10.78	11.11	0.33	3.0	22.2	10.78	11.11	0.33	3.0	22.2
3	100	18.06	18.46	0.40	2.2	18.5	18.06	18.46	0.40	2.2	18.5
4	150	25.34	25.82	0.48	1.9	17.2	25.34	25.82	0.48	1.9	17.2
5	200	32.62	33.18	0.55	1.7	16.6	32.62	33.18	0.55	1.7	16.6
6	250	39.91	40.53	0.63	1.6	16.2	39.91	40.53	0.63	1.6	16.2
7	300	47.19	47.89	0.70	1.5	16.0	47.19	47.89	0.70	1.5	16.0
8	350	54.47	55.25	0.78	1.4	15.8	54.47	55.25	0.78	1.4	15.8
9	400	61.75	62.60	0.86	1.4	15.7	61.75	62.60	0.86	1.4	15.7
10	450	69.03	69.96	0.93	1.3	15.5	69.03	69.96	0.93	1.3	15.5
11	500	76.31	77.32	1.01	1.3	15.5	76.31	77.32	1.01	1.3	15.5
12	550	83.59	84.67	1.08	1.3	15.4	83.59	84.67	1.08	1.3	15.4
13	600	90.87	92.03	1.16	1.3	15.3	90.87	92.03	1.16	1.3	15.3
14	650	99.79	100.96	1.17	1.2	15.5	98.15	99.39	1.23	1.3	15.3
15	700	108.71	109.89	1.19	1.1	15.7	105.44	106.74	1.31	1.2	15.2
16	750	117.62	118.83	1.20	1.0	15.8	112.72	114.10	1.38	1.2	15.2
17	800	126.54	127.76	1.22	1.0	16.0	120.00	121.46	1.46	1.2	15.2
18	850	135.46	136.69	1.23	0.9	16.1	127.28	128.81	1.54	1.2	15.2
19	900	144.37	145.62	1.25	0.9	16.2	134.56	136.17	1.61	1.2	15.1
20	950	153.29	154.55	1.26	0.8	16.3	141.84	143.53	1.69	1.2	15.1
21	1,000	162.21	163.49	1.28	0.8	16.3	149.12	150.89	1.76	1.2	15.1
22	1,500	251.37	252.80	1.43	0.6	16.9	221.93	224.45	2.52	1.1	15.0
23	2,000	340.54	342.12	1.58	0.5	17.1	294.74	298.02	3.28	1.1	14.9
24	2,500	429.70	431.44	1.73	0.4	17.3	367.56	371.59	4.03	1.1	14.9
25	3,000	518.87	520.76	1.89	0.4	17.4	440.37	445.16	4.79	1.1	14.8
26	3,500	608.04	610.07	2.04	0.3	17.4	513.18	518.72	5.55	1.1	14.8
27	4,000	697.20	699.39	2.19	0.3	17.5	585.99	592.29	6.30	1.1	14.8
28	4,500	786.37	788.71	2.34	0.3	17.5	658.80	665.86	7.06	1.1	14.8
29	5,000	875.53	878.03	2.49	0.3	17.6	731.61	739.43	7.82	1.1	14.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
First 600 kWh/mth	0.094525	0.097683	0.094525	0.097683
Excess kWh/mth	0.127235	0.129183	0.094525	0.097683
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	3.50	3.75	3.50	3.75

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Service RS AMI Opt Out
Income Assistance Provision RIA
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 6 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	0.73	0.74	0.01	1.0	14.7	0.73	0.74	0.01	1.0	14.7
2	50	7.28	7.36	0.08	1.0	14.7	7.28	7.36	0.08	1.0	14.7
3	100	14.56	14.71	0.15	1.0	14.7	14.56	14.71	0.15	1.0	14.7
4	150	21.84	22.07	0.23	1.0	14.7	21.84	22.07	0.23	1.0	14.7
5	200	29.12	29.43	0.30	1.0	14.7	29.12	29.43	0.30	1.0	14.7
6	250	36.41	36.78	0.38	1.0	14.7	36.41	36.78	0.38	1.0	14.7
7	300	43.69	44.14	0.45	1.0	14.7	43.69	44.14	0.45	1.0	14.7
8	350	50.97	51.50	0.53	1.0	14.7	50.97	51.50	0.53	1.0	14.7
9	400	58.25	58.85	0.61	1.0	14.7	58.25	58.85	0.61	1.0	14.7
10	450	65.53	66.21	0.68	1.0	14.7	65.53	66.21	0.68	1.0	14.7
11	500	72.81	73.57	0.76	1.0	14.7	72.81	73.57	0.76	1.0	14.7
12	550	80.09	80.92	0.83	1.0	14.7	80.09	80.92	0.83	1.0	14.7
13	600	87.37	88.28	0.91	1.0	14.7	87.37	88.28	0.91	1.0	14.7
14	650	96.29	97.21	0.92	1.0	15.0	94.65	95.64	0.98	1.0	14.7
15	700	105.21	106.14	0.94	0.9	15.2	101.94	102.99	1.06	1.0	14.7
16	750	114.12	115.08	0.95	0.8	15.3	109.22	110.35	1.13	1.0	14.7
17	800	123.04	124.01	0.97	0.8	15.5	116.50	117.71	1.21	1.0	14.7
18	850	131.96	132.94	0.98	0.7	15.6	123.78	125.06	1.29	1.0	14.7
19	900	140.87	141.87	1.00	0.7	15.8	131.06	132.42	1.36	1.0	14.7
20	950	149.79	150.80	1.01	0.7	15.9	138.34	139.78	1.44	1.0	14.7
21	1,000	158.71	159.74	1.03	0.6	16.0	145.62	147.14	1.51	1.0	14.7
22	1,500	247.87	249.05	1.18	0.5	16.6	218.43	220.70	2.27	1.0	14.7
23	2,000	337.04	338.37	1.33	0.4	16.9	291.24	294.27	3.03	1.0	14.7
24	2,500	426.20	427.69	1.48	0.3	17.1	364.06	367.84	3.78	1.0	14.7
25	3,000	515.37	517.01	1.64	0.3	17.2	436.87	441.41	4.54	1.0	14.7
26	3,500	604.54	606.32	1.79	0.3	17.3	509.68	514.97	5.30	1.0	14.7
27	4,000	693.70	695.64	1.94	0.3	17.4	582.49	588.54	6.05	1.0	14.7
28	4,500	782.87	784.96	2.09	0.3	17.4	655.30	662.11	6.81	1.0	14.7
29	5,000	872.03	874.28	2.24	0.3	17.5	728.11	735.68	7.57	1.0	14.7

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
First 600 kWh/mth	0.094525	0.097683	0.094525	0.097683
Excess kWh/mth	0.127235	0.129183	0.094525	0.097683
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	-	-	-	-

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Time-of-Day RT
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 7 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	7.69	8.23	0.54	7.0	164.6	7.67	8.23	0.55	7.2	164.5
2	50	13.91	14.80	0.89	6.4	29.6	13.73	14.75	1.02	7.4	29.5
3	100	20.81	22.09	1.28	6.2	22.1	20.47	22.00	1.53	7.5	22.0
4	150	27.72	29.39	1.67	6.0	19.6	27.20	29.25	2.05	7.5	19.5
5	200	34.63	36.69	2.06	6.0	18.3	33.94	36.50	2.57	7.6	18.3
6	250	41.53	43.99	2.45	5.9	17.6	40.67	43.75	3.08	7.6	17.5
7	300	48.44	51.28	2.85	5.9	17.1	47.41	51.01	3.60	7.6	17.0
8	350	55.34	58.58	3.24	5.8	16.7	54.14	58.26	4.12	7.6	16.6
9	400	62.25	65.88	3.63	5.8	16.5	60.87	65.51	4.63	7.6	16.4
10	450	69.16	73.17	4.02	5.8	16.3	67.61	72.76	5.15	7.6	16.2
11	500	76.06	80.47	4.41	5.8	16.1	74.34	80.01	5.67	7.6	16.0
12	550	82.97	87.77	4.80	5.8	16.0	81.08	87.26	6.18	7.6	15.9
13	600	89.88	95.07	5.19	5.8	15.8	87.81	94.51	6.70	7.6	15.8
14	650	96.78	102.36	5.58	5.8	15.7	94.54	101.76	7.22	7.6	15.7
15	700	103.69	109.66	5.97	5.8	15.7	101.28	109.01	7.73	7.6	15.6
16	750	110.59	116.96	6.36	5.8	15.6	108.01	116.26	8.25	7.6	15.5
17	800	117.50	124.26	6.75	5.7	15.5	114.75	123.52	8.77	7.6	15.4
18	850	124.41	131.55	7.15	5.7	15.5	121.48	130.77	9.28	7.6	15.4
19	900	131.31	138.85	7.54	5.7	15.4	128.22	138.02	9.80	7.6	15.3
20	950	138.22	146.15	7.93	5.7	15.4	134.95	145.27	10.32	7.6	15.3
21	1,000	145.13	153.44	8.32	5.7	15.3	141.68	152.52	10.83	7.6	15.3
22	1,500	214.19	226.42	12.23	5.7	15.1	209.03	225.03	16.00	7.7	15.0
23	2,000	283.25	299.39	16.14	5.7	15.0	276.37	297.54	21.17	7.7	14.9
24	2,500	352.32	372.36	20.05	5.7	14.9	343.71	370.05	26.34	7.7	14.8
25	3,000	421.38	445.33	23.95	5.7	14.8	411.05	442.56	31.50	7.7	14.8
26	3,500	490.44	518.30	27.86	5.7	14.8	478.39	515.07	36.67	7.7	14.7
27	4,000	559.51	591.28	31.77	5.7	14.8	545.74	587.58	41.84	7.7	14.7
28	4,500	628.57	664.25	35.68	5.7	14.8	613.08	660.09	47.01	7.7	14.7
29	5,000	697.63	737.22	39.59	5.7	14.7	680.42	732.60	52.17	7.7	14.7

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kWh/mth	0.113073	0.126109	0.091202	0.105383
Off-peak kWh/mth	0.078348	0.086620	0.081049	0.092295
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	7.00	7.50	7.00	7.50

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Time-of-Day RT
Senior Citizen Provision RSC
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	4.19	4.48	0.29	6.9	89.6	4.17	4.48	0.30	7.2	89.5
2	50	10.41	11.05	0.64	6.2	22.1	10.23	11.00	0.77	7.5	22.0
3	100	17.31	18.34	1.03	6.0	18.3	16.97	18.25	1.28	7.6	18.3
4	150	24.22	25.64	1.42	5.9	17.1	23.70	25.50	1.80	7.6	17.0
5	200	31.13	32.94	1.81	5.8	16.5	30.44	32.75	2.32	7.6	16.4
6	250	38.03	40.24	2.20	5.8	16.1	37.17	40.00	2.83	7.6	16.0
7	300	44.94	47.53	2.60	5.8	15.8	43.91	47.26	3.35	7.6	15.8
8	350	51.84	54.83	2.99	5.8	15.7	50.64	54.51	3.87	7.6	15.6
9	400	58.75	62.13	3.38	5.7	15.5	57.37	61.76	4.38	7.6	15.4
10	450	65.66	69.42	3.77	5.7	15.4	64.11	69.01	4.90	7.6	15.3
11	500	72.56	76.72	4.16	5.7	15.3	70.84	76.26	5.42	7.6	15.3
12	550	79.47	84.02	4.55	5.7	15.3	77.58	83.51	5.93	7.6	15.2
13	600	86.38	91.32	4.94	5.7	15.2	84.31	90.76	6.45	7.7	15.1
14	650	93.28	98.61	5.33	5.7	15.2	91.04	98.01	6.97	7.7	15.1
15	700	100.19	105.91	5.72	5.7	15.1	97.78	105.26	7.48	7.7	15.0
16	750	107.09	113.21	6.11	5.7	15.1	104.51	112.51	8.00	7.7	15.0
17	800	114.00	120.51	6.50	5.7	15.1	111.25	119.77	8.52	7.7	15.0
18	850	120.91	127.80	6.90	5.7	15.0	117.98	127.02	9.03	7.7	14.9
19	900	127.81	135.10	7.29	5.7	15.0	124.72	134.27	9.55	7.7	14.9
20	950	134.72	142.40	7.68	5.7	15.0	131.45	141.52	10.07	7.7	14.9
21	1,000	141.63	149.69	8.07	5.7	15.0	138.18	148.77	10.58	7.7	14.9
22	1,500	210.69	222.67	11.98	5.7	14.8	205.53	221.28	15.75	7.7	14.8
23	2,000	279.75	295.64	15.89	5.7	14.8	272.87	293.79	20.92	7.7	14.7
24	2,500	348.82	368.61	19.80	5.7	14.7	340.21	366.30	26.09	7.7	14.7
25	3,000	417.88	441.58	23.70	5.7	14.7	407.55	438.81	31.25	7.7	14.6
26	3,500	486.94	514.55	27.61	5.7	14.7	474.89	511.32	36.42	7.7	14.6
27	4,000	556.01	587.53	31.52	5.7	14.7	542.24	583.83	41.59	7.7	14.6
28	4,500	625.07	660.50	35.43	5.7	14.7	609.58	656.34	46.76	7.7	14.6
29	5,000	694.13	733.47	39.34	5.7	14.7	676.92	728.85	51.92	7.7	14.6

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kWh/mth	0.113073	0.126109	0.091202	0.105383
Off-peak kWh/mth	0.078348	0.086620	0.081049	0.092295
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	3.50	3.75	3.50	3.75

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Time-of-Day RT
Income Assistance Provision RIA
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	0.69	0.73	0.04	5.7	14.6	0.67	0.73	0.05	7.7	14.5
2	50	6.91	7.30	0.39	5.7	14.6	6.73	7.25	0.52	7.7	14.5
3	100	13.81	14.59	0.78	5.7	14.6	13.47	14.50	1.03	7.7	14.5
4	150	20.72	21.89	1.17	5.7	14.6	20.20	21.75	1.55	7.7	14.5
5	200	27.63	29.19	1.56	5.7	14.6	26.94	29.00	2.07	7.7	14.5
6	250	34.53	36.49	1.95	5.7	14.6	33.67	36.25	2.58	7.7	14.5
7	300	41.44	43.78	2.35	5.7	14.6	40.41	43.51	3.10	7.7	14.5
8	350	48.34	51.08	2.74	5.7	14.6	47.14	50.76	3.62	7.7	14.5
9	400	55.25	58.38	3.13	5.7	14.6	53.87	58.01	4.13	7.7	14.5
10	450	62.16	65.67	3.52	5.7	14.6	60.61	65.26	4.65	7.7	14.5
11	500	69.06	72.97	3.91	5.7	14.6	67.34	72.51	5.17	7.7	14.5
12	550	75.97	80.27	4.30	5.7	14.6	74.08	79.76	5.68	7.7	14.5
13	600	82.88	87.57	4.69	5.7	14.6	80.81	87.01	6.20	7.7	14.5
14	650	89.78	94.86	5.08	5.7	14.6	87.54	94.26	6.72	7.7	14.5
15	700	96.69	102.16	5.47	5.7	14.6	94.28	101.51	7.23	7.7	14.5
16	750	103.59	109.46	5.86	5.7	14.6	101.01	108.76	7.75	7.7	14.5
17	800	110.50	116.76	6.25	5.7	14.6	107.75	116.02	8.27	7.7	14.5
18	850	117.41	124.05	6.65	5.7	14.6	114.48	123.27	8.78	7.7	14.5
19	900	124.31	131.35	7.04	5.7	14.6	121.22	130.52	9.30	7.7	14.5
20	950	131.22	138.65	7.43	5.7	14.6	127.95	137.77	9.82	7.7	14.5
21	1,000	138.13	145.94	7.82	5.7	14.6	134.68	145.02	10.33	7.7	14.5
22	1,500	207.19	218.92	11.73	5.7	14.6	202.03	217.53	15.50	7.7	14.5
23	2,000	276.25	291.89	15.64	5.7	14.6	269.37	290.04	20.67	7.7	14.5
24	2,500	345.32	364.86	19.55	5.7	14.6	336.71	362.55	25.84	7.7	14.5
25	3,000	414.38	437.83	23.45	5.7	14.6	404.05	435.06	31.00	7.7	14.5
26	3,500	483.44	510.80	27.36	5.7	14.6	471.39	507.57	36.17	7.7	14.5
27	4,000	552.51	583.78	31.27	5.7	14.6	538.74	580.08	41.34	7.7	14.5
28	4,500	621.57	656.75	35.18	5.7	14.6	606.08	652.59	46.51	7.7	14.5
29	5,000	690.63	729.72	39.09	5.7	14.6	673.42	725.10	51.67	7.7	14.5

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kWh/mth	0.113073	0.126109	0.091202	0.105383
Off-peak kWh/mth	0.078348	0.086620	0.081049	0.092295
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	-	0.00	0.00	0.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Electric Vehicle REV
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 10 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	7.78	8.30	0.52	6.7	165.9	7.70	8.23	0.53	6.8	164.6
2	50	14.77	15.46	0.68	4.6	30.9	14.05	14.82	0.77	5.5	29.6
3	100	22.55	23.42	0.87	3.8	23.4	21.09	22.13	1.04	4.9	22.1
4	150	30.32	31.37	1.05	3.5	20.9	28.14	29.45	1.31	4.6	19.6
5	200	38.10	39.33	1.23	3.2	19.7	35.19	36.76	1.58	4.5	18.4
6	250	45.87	47.29	1.42	3.1	18.9	42.23	44.08	1.85	4.4	17.6
7	300	53.65	55.25	1.60	3.0	18.4	49.28	51.40	2.12	4.3	17.1
8	350	61.42	63.20	1.78	2.9	18.1	56.33	58.71	2.39	4.2	16.8
9	400	69.20	71.16	1.96	2.8	17.8	63.37	66.03	2.66	4.2	16.5
10	450	76.97	79.12	2.15	2.8	17.6	70.42	73.34	2.93	4.2	16.3
11	500	84.75	87.08	2.33	2.8	17.4	77.47	80.66	3.19	4.1	16.1
12	550	92.52	95.03	2.51	2.7	17.3	84.51	87.98	3.46	4.1	16.0
13	600	100.30	102.99	2.70	2.7	17.2	91.56	95.29	3.73	4.1	15.9
14	650	108.07	110.95	2.88	2.7	17.1	98.61	102.61	4.00	4.1	15.8
15	700	115.84	118.91	3.06	2.6	17.0	105.65	109.93	4.27	4.0	15.7
16	750	123.62	126.87	3.25	2.6	16.9	112.70	117.24	4.54	4.0	15.6
17	800	131.39	134.82	3.43	2.6	16.9	119.75	124.56	4.81	4.0	15.6
18	850	139.17	142.78	3.61	2.6	16.8	126.79	131.87	5.08	4.0	15.5
19	900	146.94	150.74	3.80	2.6	16.7	133.84	139.19	5.35	4.0	15.5
20	950	154.72	158.70	3.98	2.6	16.7	140.89	146.51	5.62	4.0	15.4
21	1,000	162.49	166.65	4.16	2.6	16.7	147.93	153.82	5.89	4.0	15.4
22	1,500	240.24	246.23	5.99	2.5	16.4	218.40	226.98	8.58	3.9	15.1
23	2,000	317.98	325.81	7.82	2.5	16.3	288.87	300.14	11.28	3.9	15.0
24	2,500	395.73	405.39	9.66	2.4	16.2	359.33	373.30	13.97	3.9	14.9
25	3,000	473.48	484.96	11.49	2.4	16.2	429.80	446.47	16.67	3.9	14.9
26	3,500	551.22	564.54	13.32	2.4	16.1	500.26	519.63	19.36	3.9	14.8
27	4,000	628.97	644.12	15.15	2.4	16.1	570.73	592.79	22.06	3.9	14.8
28	4,500	706.71	723.69	16.98	2.4	16.1	641.20	665.95	24.75	3.9	14.8
29	5,000	784.46	803.27	18.81	2.4	16.1	711.66	739.11	27.44	3.9	14.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kWh/mth	0.146505	0.157295	0.096787	0.108696
Mid-peak kWh/mth	0.117012	0.123595	-	-
Off-peak kWh/mth	0.083957	0.086868	0.083957	0.086868
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	7.00	7.50	7.00	7.50

REV Load Profi	Summer	Winter
On Peak	14%	46%
Mid Peak	36%	
Off Peak	50%	54%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Dynamic Pricing RDP
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	7.62	8.24	0.62	8.1	164.8	7.73	8.19	0.46	6.0	163.8
2	50	13.22	14.92	1.70	12.8	29.8	14.28	14.41	0.12	0.9	28.8
3	100	19.45	22.34	2.90	14.9	22.3	21.57	21.31	(0.26)	(1.2)	21.3
4	150	25.67	29.76	4.09	15.9	19.8	28.85	28.22	(0.63)	(2.2)	18.8
5	200	31.89	37.19	5.29	16.6	18.6	36.14	35.12	(1.01)	(2.8)	17.6
6	250	38.12	44.61	6.49	17.0	17.8	43.42	42.03	(1.39)	(3.2)	16.8
7	300	44.34	52.03	7.69	17.3	17.3	50.71	48.94	(1.77)	(3.5)	16.3
8	350	50.56	59.45	8.88	17.6	17.0	57.99	55.84	(2.15)	(3.7)	16.0
9	400	56.79	66.87	10.08	17.8	16.7	65.27	62.75	(2.53)	(3.9)	15.7
10	450	63.01	74.29	11.28	17.9	16.5	72.56	69.65	(2.90)	(4.0)	15.5
11	500	69.23	81.71	12.48	18.0	16.3	79.84	76.56	(3.28)	(4.1)	15.3
12	550	75.46	89.13	13.68	18.1	16.2	87.13	83.47	(3.66)	(4.2)	15.2
13	600	81.68	96.56	14.87	18.2	16.1	94.41	90.37	(4.04)	(4.3)	15.1
14	650	87.90	103.98	16.07	18.3	16.0	101.69	97.28	(4.42)	(4.3)	15.0
15	700	94.13	111.40	17.27	18.3	15.9	108.98	104.18	(4.79)	(4.4)	14.9
16	750	100.35	118.82	18.47	18.4	15.8	116.26	111.09	(5.17)	(4.4)	14.8
17	800	106.58	126.24	19.67	18.5	15.8	123.55	118.00	(5.55)	(4.5)	14.7
18	850	112.80	133.66	20.86	18.5	15.7	130.83	124.90	(5.93)	(4.5)	14.7
19	900	119.02	141.08	22.06	18.5	15.7	138.12	131.81	(6.31)	(4.6)	14.6
20	950	125.25	148.50	23.26	18.6	15.6	145.40	138.71	(6.69)	(4.6)	14.6
21	1,000	131.47	155.93	24.46	18.6	15.6	152.68	145.62	(7.06)	(4.6)	14.6
22	1,500	193.70	230.14	36.43	18.8	15.3	225.53	214.68	(10.85)	(4.8)	14.3
23	2,000	255.94	304.35	48.41	18.9	15.2	298.37	283.74	(14.63)	(4.9)	14.2
24	2,500	318.17	378.56	60.39	19.0	15.1	371.21	352.80	(18.41)	(5.0)	14.1
25	3,000	380.41	452.78	72.37	19.0	15.1	444.05	421.86	(22.19)	(5.0)	14.1
26	3,500	442.64	526.99	84.35	19.1	15.1	516.90	490.92	(25.97)	(5.0)	14.0
27	4,000	504.88	601.20	96.33	19.1	15.0	589.74	559.98	(29.76)	(5.0)	14.0
28	4,500	567.11	675.41	108.30	19.1	15.0	662.58	629.04	(33.54)	(5.1)	14.0
29	5,000	629.34	749.63	120.28	19.1	15.0	735.42	698.10	(37.32)	(5.1)	14.0

	Summer Present	Summer Proposed	Winter Present	Winter Proposed
Power Supply Charges				
On-peak kWh/mth	0.103467	0.142661	0.101313	0.098582
Mid-peak kWh/mth	0.082639	0.112097	-	-
Off-peak kWh/mth	0.059294	0.078786	0.087883	0.078786
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	7.00	7.50	7.00	7.50

REV Load Profi	Summer	Winter
On Peak	12%	50%
Mid Peak	38%	
Off Peak	50%	50%

Schedule F-4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	7.74	8.33	0.59	7.6	166.6	7.73	8.19	0.46	6.0	163.8
2	50	14.39	15.79	1.41	9.8	31.6	14.29	14.42	0.13	0.9	28.8
3	100	21.78	24.09	2.31	10.6	24.1	21.59	21.34	(0.25)	(1.1)	21.3
4	150	29.17	32.38	3.22	11.0	21.6	28.88	28.27	(0.62)	(2.1)	18.8
5	200	36.56	40.68	4.12	11.3	20.3	36.18	35.19	(0.99)	(2.7)	17.6
6	250	43.95	48.97	5.03	11.4	19.6	43.47	42.11	(1.37)	(3.1)	16.8
7	300	51.34	57.27	5.93	11.6	19.1	50.77	49.03	(1.74)	(3.4)	16.3
8	350	58.73	65.56	6.84	11.6	18.7	58.06	55.95	(2.11)	(3.6)	16.0
9	400	66.11	73.86	7.74	11.7	18.5	65.36	62.87	(2.49)	(3.8)	15.7
10	450	73.50	82.15	8.65	11.8	18.3	72.65	69.80	(2.86)	(3.9)	15.5
11	500	80.89	90.45	9.55	11.8	18.1	79.95	76.72	(3.23)	(4.0)	15.3
12	550	88.28	98.74	10.46	11.8	18.0	87.24	83.64	(3.60)	(4.1)	15.2
13	600	95.67	107.04	11.36	11.9	17.8	94.54	90.56	(3.98)	(4.2)	15.1
14	650	103.06	115.33	12.27	11.9	17.7	101.83	97.48	(4.35)	(4.3)	15.0
15	700	110.45	123.62	13.17	11.9	17.7	109.13	104.40	(4.72)	(4.3)	14.9
16	750	117.84	131.92	14.08	11.9	17.6	116.42	111.33	(5.10)	(4.4)	14.8
17	800	125.23	140.21	14.98	12.0	17.5	123.72	118.25	(5.47)	(4.4)	14.8
18	850	132.62	148.51	15.89	12.0	17.5	131.01	125.17	(5.84)	(4.5)	14.7
19	900	140.01	156.80	16.80	12.0	17.4	138.31	132.09	(6.22)	(4.5)	14.7
20	950	147.40	165.10	17.70	12.0	17.4	145.60	139.01	(6.59)	(4.5)	14.6
21	1,000	154.79	173.39	18.61	12.0	17.3	152.90	145.93	(6.96)	(4.6)	14.6
22	1,500	228.68	256.34	27.66	12.1	17.1	225.85	215.15	(10.69)	(4.7)	14.3
23	2,000	302.57	339.28	36.71	12.1	17.0	298.80	284.37	(14.43)	(4.8)	14.2
24	2,500	376.46	422.23	45.76	12.2	16.9	371.74	353.59	(18.16)	(4.9)	14.1
25	3,000	450.36	505.18	54.82	12.2	16.8	444.69	422.80	(21.89)	(4.9)	14.1
26	3,500	524.25	588.12	63.87	12.2	16.8	517.64	492.02	(25.62)	(4.9)	14.1
27	4,000	598.14	671.07	72.92	12.2	16.8	590.59	561.24	(29.35)	(5.0)	14.0
28	4,500	672.04	754.01	81.98	12.2	16.8	663.54	630.46	(33.08)	(5.0)	14.0
29	5,000	745.93	836.96	91.03	12.2	16.7	736.49	699.67	(36.81)	(5.0)	14.0

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kWh/mth	0.135349	0.166080	0.101313	0.098582
Mid-peak kWh/mth	0.108102	0.130726	-	-
Off-peak kWh/mth	0.077564	0.092170	0.087883	0.078786
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.050297	0.048652	0.050297	0.048652
System Access	7.00	7.50	7.00	7.50

REV Load Profi	Summer	Winter
On Peak	13%	52%
Mid Peak	38%	
Off Peak	49%	48%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Energy-only GS
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
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Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	250	55.05	55.92	0.87	1.6	22.4	54.07	55.67	1.60	3.0	22.3
2	500	90.10	91.84	1.74	1.9	18.4	88.14	91.34	3.20	3.6	18.3
3	750	125.15	127.76	2.61	2.1	17.0	122.21	127.01	4.80	3.9	16.9
4	1,000	160.20	163.68	3.48	2.2	16.4	156.28	162.67	6.40	4.1	16.3
5	1,500	230.30	235.51	5.22	2.3	15.7	224.42	234.01	9.59	4.3	15.6
6	2,000	300.39	307.35	6.96	2.3	15.4	292.56	305.35	12.79	4.4	15.3
7	2,500	370.49	379.19	8.70	2.3	15.2	360.70	376.69	15.99	4.4	15.1
8	3,000	440.59	451.03	10.44	2.4	15.0	428.84	448.02	19.19	4.5	14.9
9	3,500	510.69	522.87	12.18	2.4	14.9	496.98	519.36	22.38	4.5	14.8
10	4,000	580.79	594.70	13.92	2.4	14.9	565.12	590.70	25.58	4.5	14.8
11	4,500	650.89	666.54	15.66	2.4	14.8	633.26	662.03	28.78	4.5	14.7
12	5,000	720.99	738.38	17.40	2.4	14.8	701.40	733.37	31.98	4.6	14.7
13	6,000	861.18	882.06	20.87	2.4	14.7	837.67	876.04	38.37	4.6	14.6
14	7,000	1,001.38	1,025.73	24.35	2.4	14.7	973.95	1,018.72	44.77	4.6	14.6
15	8,000	1,141.58	1,169.41	27.83	2.4	14.6	1,110.23	1,161.39	51.16	4.6	14.5
16	9,000	1,281.77	1,313.08	31.31	2.4	14.6	1,246.51	1,304.07	57.56	4.6	14.5
17	10,000	1,421.97	1,456.76	34.79	2.4	14.6	1,382.79	1,446.74	63.95	4.6	14.5
18	15,000	2,122.96	2,175.14	52.18	2.5	14.5	2,064.19	2,160.11	95.93	4.6	14.4
19	20,000	2,823.94	2,893.52	69.58	2.5	14.5	2,745.58	2,873.48	127.90	4.7	14.4
20	25,000	3,524.93	3,611.90	86.98	2.5	14.4	3,426.98	3,586.85	159.88	4.7	14.3
21	30,000	4,225.91	4,330.28	104.37	2.5	14.4	4,108.37	4,300.22	191.85	4.7	14.3
22	35,000	4,926.90	5,048.66	121.77	2.5	14.4	4,789.77	5,013.59	223.83	4.7	14.3
23	40,000	5,627.88	5,767.04	139.16	2.5	14.4	5,471.16	5,726.96	255.80	4.7	14.3
24	45,000	6,328.87	6,485.42	156.56	2.5	14.4	6,152.56	6,440.33	287.78	4.7	14.3
25	50,000	7,029.85	7,203.80	173.95	2.5	14.4	6,833.95	7,153.70	319.75	4.7	14.3
26	55,000	7,730.84	7,922.18	191.35	2.5	14.4	7,515.35	7,867.07	351.73	4.7	14.3
27	60,000	8,431.82	8,640.56	208.74	2.5	14.4	8,196.74	8,580.44	383.70	4.7	14.3
28	65,000	9,132.81	9,358.94	226.14	2.5	14.4	8,878.14	9,293.81	415.68	4.7	14.3
29	70,000	9,833.79	10,077.32	243.53	2.5	14.4	9,559.53	10,007.18	447.65	4.7	14.3

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	0.096799	0.098922	0.092881	0.097920
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.042598	0.043954	0.042598	0.043954
System Access	20.00	20.00	20.00	20.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
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Witness: LMCollins
Date: May 2018

Secondary Energy-only GS
Education Provision GEI
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	250	54.87	55.73	0.86	1.6	22.3	53.89	55.48	1.59	2.9	22.2
2	500	89.74	91.46	1.72	1.9	18.3	87.79	90.96	3.18	3.6	18.2
3	750	124.62	127.19	2.58	2.1	17.0	121.68	126.44	4.76	3.9	16.9
4	1,000	159.49	162.92	3.43	2.2	16.3	155.57	161.92	6.35	4.1	16.2
5	1,500	229.23	234.38	5.15	2.2	15.6	223.36	232.88	9.53	4.3	15.5
6	2,000	298.98	305.85	6.87	2.3	15.3	291.14	303.84	12.70	4.4	15.2
7	2,500	368.72	377.31	8.58	2.3	15.1	358.93	374.80	15.88	4.4	15.0
8	3,000	438.47	448.77	10.30	2.3	15.0	426.71	445.76	19.05	4.5	14.9
9	3,500	508.21	520.23	12.02	2.4	14.9	494.50	516.72	22.23	4.5	14.8
10	4,000	577.96	591.69	13.74	2.4	14.8	562.28	587.68	25.40	4.5	14.7
11	4,500	647.70	663.15	15.45	2.4	14.7	630.07	658.64	28.58	4.5	14.6
12	5,000	717.45	734.62	17.17	2.4	14.7	697.86	729.61	31.75	4.5	14.6
13	6,000	856.93	877.54	20.60	2.4	14.6	833.43	871.53	38.10	4.6	14.5
14	7,000	996.42	1,020.46	24.04	2.4	14.6	969.00	1,013.45	44.45	4.6	14.5
15	8,000	1,135.91	1,163.38	27.47	2.4	14.5	1,104.57	1,155.37	50.80	4.6	14.4
16	9,000	1,275.40	1,306.31	30.91	2.4	14.5	1,240.14	1,297.29	57.15	4.6	14.4
17	10,000	1,414.89	1,449.23	34.34	2.4	14.5	1,375.71	1,439.21	63.50	4.6	14.4
18	15,000	2,112.34	2,163.85	51.51	2.4	14.4	2,053.57	2,148.82	95.25	4.6	14.3
19	20,000	2,809.78	2,878.46	68.68	2.4	14.4	2,731.42	2,858.42	127.00	4.6	14.3
20	25,000	3,507.23	3,593.08	85.85	2.4	14.4	3,409.28	3,568.03	158.75	4.7	14.3
21	30,000	4,204.67	4,307.69	103.02	2.5	14.4	4,087.13	4,277.63	190.50	4.7	14.3
22	35,000	4,902.12	5,022.31	120.19	2.5	14.3	4,764.99	4,987.24	222.25	4.7	14.2
23	40,000	5,599.56	5,736.92	137.36	2.5	14.3	5,442.84	5,696.84	254.00	4.7	14.2
24	45,000	6,297.01	6,451.54	154.53	2.5	14.3	6,120.70	6,406.45	285.75	4.7	14.2
25	50,000	6,994.45	7,166.15	171.70	2.5	14.3	6,798.55	7,116.05	317.50	4.7	14.2
26	55,000	7,691.90	7,880.77	188.87	2.5	14.3	7,476.41	7,825.66	349.25	4.7	14.2
27	60,000	8,389.34	8,595.38	206.04	2.5	14.3	8,154.26	8,535.26	381.00	4.7	14.2
28	65,000	9,086.79	9,310.00	223.21	2.5	14.3	8,832.12	9,244.87	412.75	4.7	14.2
29	70,000	9,784.23	10,024.61	240.38	2.5	14.3	9,509.97	9,954.47	444.50	4.7	14.2

	Summer Present	Summer Proposed	Winter Present	Winter Proposed
Power Supply Charges				
All kWh/mth	0.096799	0.098922	0.092881	0.097920
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.041890	0.043201	0.041890	0.043201
System Access	20.00	20.00	20.00	20.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Demand GSD
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 15 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	104.07	106.82	2.75	2.6	21.4	98.06	98.80	0.74	0.8	19.8
2	1,000	178.14	183.64	5.50	3.1	18.4	166.12	167.60	1.48	0.9	16.8
3	1,500	252.20	260.46	8.26	3.3	17.4	234.18	236.40	2.22	1.0	15.8
4	2,000	326.27	337.28	11.01	3.4	16.9	302.24	305.20	2.97	1.0	15.3
5	2,500	400.34	414.10	13.76	3.4	16.6	370.29	374.00	3.71	1.0	15.0
6	3,000	474.41	490.92	16.51	3.5	16.4	438.35	442.80	4.45	1.0	14.8
7	3,500	548.48	567.74	19.26	3.5	16.2	506.41	511.60	5.19	1.0	14.6
8	4,000	622.54	644.56	22.01	3.5	16.1	574.47	580.40	5.93	1.0	14.5
9	4,500	696.61	721.38	24.77	3.6	16.0	642.53	649.20	6.67	1.0	14.4
10	5,000	770.68	798.20	27.52	3.6	16.0	710.59	718.01	7.42	1.0	14.4
11	6,000	918.82	951.84	33.02	3.6	15.9	846.71	855.61	8.90	1.1	14.3
12	7,000	1,066.95	1,105.48	38.53	3.6	15.8	982.83	993.21	10.38	1.1	14.2
13	8,000	1,215.09	1,259.12	44.03	3.6	15.7	1,118.94	1,130.81	11.87	1.1	14.1
14	9,000	1,363.23	1,412.76	49.53	3.6	15.7	1,255.06	1,268.41	13.35	1.1	14.1
15	10,000	1,511.36	1,566.40	55.04	3.6	15.7	1,391.18	1,406.01	14.83	1.1	14.1
16	15,000	2,252.04	2,334.60	82.56	3.7	15.6	2,071.77	2,094.02	22.25	1.1	14.0
17	20,000	2,992.72	3,102.80	110.07	3.7	15.5	2,752.36	2,782.02	29.66	1.1	13.9
18	25,000	3,733.41	3,871.00	137.59	3.7	15.5	3,432.95	3,470.03	37.08	1.1	13.9
19	30,000	4,474.09	4,639.20	165.11	3.7	15.5	4,113.54	4,158.03	44.49	1.1	13.9
20	35,000	5,214.77	5,407.40	192.63	3.7	15.4	4,794.13	4,846.04	51.91	1.1	13.8
21	40,000	5,955.45	6,175.60	220.15	3.7	15.4	5,474.72	5,534.04	59.33	1.1	13.8
22	45,000	6,696.13	6,943.80	247.67	3.7	15.4	6,155.31	6,222.05	66.74	1.1	13.8
23	50,000	7,436.81	7,712.00	275.19	3.7	15.4	6,835.90	6,910.05	74.16	1.1	13.8
24	55,000	8,177.49	8,480.20	302.71	3.7	15.4	7,516.49	7,598.06	81.57	1.1	13.8
25	60,000	8,918.17	9,248.40	330.22	3.7	15.4	8,197.08	8,286.07	88.99	1.1	13.8
26	65,000	9,658.86	10,016.60	357.74	3.7	15.4	8,877.67	8,974.07	96.40	1.1	13.8
27	70,000	10,399.54	10,784.80	385.26	3.7	15.4	9,558.26	9,662.08	103.82	1.1	13.8
28	75,000	11,140.22	11,553.00	412.78	3.7	15.4	10,238.85	10,350.08	111.24	1.1	13.8
29	80,000	11,880.90	12,321.20	440.30	3.7	15.4	10,919.44	11,038.09	118.65	1.1	13.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
Peak kW/mth	12.17	21.56	10.17	17.55
All kWh/mth	0.066606	0.043336	0.061437	0.041030
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Peak kW/mth	1.15	1.15	1.15	1.15
Distribution kWh/mth	0.035114	0.031730	0.035114	0.031730
System Access	30.00	30.00	30.00	30.00

Load Profile	
Load Factor	40%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

Secondary Demand GSD
Education Provision GEI
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	103.76	106.51	2.75	2.7	21.3	97.75	98.49	0.74	0.8	19.7
2	1,000	177.52	183.02	5.50	3.1	18.3	165.50	166.98	1.48	0.9	16.7
3	1,500	251.28	259.53	8.25	3.3	17.3	233.25	235.47	2.22	1.0	15.7
4	2,000	325.03	336.04	11.00	3.4	16.8	301.00	303.96	2.96	1.0	15.2
5	2,500	398.79	412.55	13.75	3.4	16.5	368.75	372.45	3.70	1.0	14.9
6	3,000	472.55	489.06	16.51	3.5	16.3	436.50	440.94	4.44	1.0	14.7
7	3,500	546.31	565.57	19.26	3.5	16.2	504.25	509.43	5.18	1.0	14.6
8	4,000	620.07	642.08	22.01	3.5	16.1	572.00	577.92	5.92	1.0	14.4
9	4,500	693.83	718.59	24.76	3.6	16.0	639.75	646.41	6.67	1.0	14.4
10	5,000	767.59	795.09	27.51	3.6	15.9	707.49	714.90	7.41	1.0	14.3
11	6,000	915.10	948.11	33.01	3.6	15.8	842.99	851.88	8.89	1.1	14.2
12	7,000	1,062.62	1,101.13	38.51	3.6	15.7	978.49	988.86	10.37	1.1	14.1
13	8,000	1,210.14	1,254.15	44.01	3.6	15.7	1,113.99	1,125.84	11.85	1.1	14.1
14	9,000	1,357.66	1,407.17	49.52	3.6	15.6	1,249.49	1,262.82	13.33	1.1	14.0
15	10,000	1,505.17	1,560.19	55.02	3.7	15.6	1,384.99	1,399.80	14.81	1.1	14.0
16	15,000	2,242.76	2,325.28	82.53	3.7	15.5	2,062.48	2,084.70	22.22	1.1	13.9
17	20,000	2,980.34	3,090.38	110.03	3.7	15.5	2,739.98	2,769.60	29.62	1.1	13.8
18	25,000	3,717.93	3,855.47	137.54	3.7	15.4	3,417.47	3,454.50	37.03	1.1	13.8
19	30,000	4,455.52	4,620.57	165.05	3.7	15.4	4,094.97	4,139.40	44.43	1.1	13.8
20	35,000	5,193.10	5,385.66	192.56	3.7	15.4	4,772.46	4,824.30	51.84	1.1	13.8
21	40,000	5,930.69	6,150.76	220.07	3.7	15.4	5,449.96	5,509.20	59.25	1.1	13.8
22	45,000	6,668.28	6,915.85	247.58	3.7	15.4	6,127.45	6,194.10	66.65	1.1	13.8
23	50,000	7,405.86	7,680.95	275.09	3.7	15.4	6,804.95	6,879.00	74.06	1.1	13.8
24	55,000	8,143.45	8,446.04	302.60	3.7	15.4	7,482.44	7,563.91	81.46	1.1	13.8
25	60,000	8,881.03	9,211.14	330.10	3.7	15.4	8,159.94	8,248.81	88.87	1.1	13.7
26	65,000	9,618.62	9,976.23	357.61	3.7	15.3	8,837.43	8,933.71	96.27	1.1	13.7
27	70,000	10,356.21	10,741.33	385.12	3.7	15.3	9,514.93	9,618.61	103.68	1.1	13.7
28	75,000	11,093.79	11,506.42	412.63	3.7	15.3	10,192.42	10,303.51	111.09	1.1	13.7
29	80,000	11,831.38	12,271.52	440.14	3.7	15.3	10,869.92	10,988.41	118.49	1.1	13.7

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
Peak kW/mth	12.17	21.56	10.17	17.55
All kWh/mth	0.066606	0.043336	0.061437	0.041030
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Peak kW/mth	1.15	1.15	1.15	1.15
Distribution kWh/mth	0.034495	0.031109	0.034495	0.031109
System Access	30.00	30.00	30.00	30.00

Load Profile	
Load Factor	40%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP (Voltage Level 1)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 17 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	147.12	144.41	(2.71)	(1.8)	28.9	145.39	143.99	(1.40)	(1.0)	28.8
2	1,000	194.25	188.82	(5.43)	(2.8)	18.9	190.78	187.99	(2.80)	(1.5)	18.8
3	1,500	241.37	233.23	(8.14)	(3.4)	15.5	236.17	231.98	(4.20)	(1.8)	15.5
4	2,000	288.49	277.64	(10.86)	(3.8)	13.9	281.57	275.97	(5.60)	(2.0)	13.8
5	2,500	335.62	322.05	(13.57)	(4.0)	12.9	326.96	319.96	(7.00)	(2.1)	12.8
6	3,000	382.74	366.45	(16.29)	(4.3)	12.2	372.35	363.96	(8.39)	(2.3)	12.1
7	4,000	476.99	455.27	(21.72)	(4.6)	11.4	463.13	451.94	(11.19)	(2.4)	11.3
8	5,000	571.24	544.09	(27.15)	(4.8)	10.9	553.92	539.93	(13.99)	(2.5)	10.8
9	6,000	665.48	632.91	(32.57)	(4.9)	10.5	644.70	627.91	(16.79)	(2.6)	10.5
10	7,000	759.73	721.73	(38.00)	(5.0)	10.3	735.48	715.90	(19.59)	(2.7)	10.2
11	8,000	853.98	810.54	(43.43)	(5.1)	10.1	826.26	803.88	(22.38)	(2.7)	10.0
12	9,000	948.22	899.36	(48.86)	(5.2)	10.0	917.05	891.87	(25.18)	(2.7)	9.9
13	10,000	1,042.47	988.18	(54.29)	(5.2)	9.9	1,007.83	979.85	(27.98)	(2.8)	9.8
14	15,000	1,513.71	1,432.27	(81.43)	(5.4)	9.5	1,461.75	1,419.78	(41.97)	(2.9)	9.5
15	20,000	1,984.94	1,876.36	(108.58)	(5.5)	9.4	1,915.66	1,859.70	(55.96)	(2.9)	9.3
16	25,000	2,456.18	2,320.45	(135.73)	(5.5)	9.3	2,369.58	2,299.63	(69.95)	(3.0)	9.2
17	30,000	2,927.41	2,764.54	(162.87)	(5.6)	9.2	2,823.49	2,739.55	(83.94)	(3.0)	9.1
18	35,000	3,398.65	3,208.63	(190.02)	(5.6)	9.2	3,277.41	3,179.48	(97.93)	(3.0)	9.1
19	40,000	3,869.88	3,652.72	(217.16)	(5.6)	9.1	3,731.32	3,619.40	(111.92)	(3.0)	9.0
20	45,000	4,341.12	4,096.81	(244.31)	(5.6)	9.1	4,185.24	4,059.33	(125.91)	(3.0)	9.0
21	50,000	4,812.35	4,540.90	(271.45)	(5.6)	9.1	4,639.15	4,499.25	(139.90)	(3.0)	9.0
22	60,000	5,754.82	5,429.08	(325.74)	(5.7)	9.0	5,546.98	5,379.10	(167.88)	(3.0)	9.0
23	70,000	6,697.29	6,317.26	(380.03)	(5.7)	9.0	6,454.81	6,258.95	(195.86)	(3.0)	8.9
24	80,000	7,639.76	7,205.44	(434.32)	(5.7)	9.0	7,362.64	7,138.80	(223.84)	(3.0)	8.9
25	90,000	8,582.23	8,093.62	(488.61)	(5.7)	9.0	8,270.47	8,018.65	(251.82)	(3.0)	8.9
26	100,000	9,524.70	8,981.80	(542.90)	(5.7)	9.0	9,178.30	8,898.50	(279.80)	(3.0)	8.9
27	110,000	10,467.17	9,869.98	(597.19)	(5.7)	9.0	10,086.13	9,778.35	(307.78)	(3.1)	8.9
28	120,000	11,409.64	10,758.16	(651.48)	(5.7)	9.0	10,993.96	10,658.20	(335.76)	(3.1)	8.9
29	130,000	12,352.11	11,646.34	(705.77)	(5.7)	9.0	11,901.79	11,538.05	(363.74)	(3.1)	8.9

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	0.085586	0.082234	0.082122	0.081401
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.007861	0.005784	0.007861	0.005784
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP (Voltage Level 1)
Education Provision GEI
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 18 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	146.86	144.15	(2.71)	(1.8)	28.8	145.13	143.74	(1.39)	(1.0)	28.7
2	1,000	193.72	188.30	(5.41)	(2.8)	18.8	190.25	187.47	(2.78)	(1.5)	18.7
3	1,500	240.58	232.46	(8.12)	(3.4)	15.5	235.38	231.21	(4.17)	(1.8)	15.4
4	2,000	287.43	276.61	(10.83)	(3.8)	13.8	280.51	274.94	(5.56)	(2.0)	13.7
5	2,500	334.29	320.76	(13.53)	(4.0)	12.8	325.63	318.68	(6.95)	(2.1)	12.7
6	3,000	381.15	364.91	(16.24)	(4.3)	12.2	370.76	362.41	(8.35)	(2.3)	12.1
7	4,000	474.87	453.22	(21.65)	(4.6)	11.3	461.01	449.88	(11.13)	(2.4)	11.2
8	5,000	568.59	541.52	(27.07)	(4.8)	10.8	551.27	537.36	(13.91)	(2.5)	10.7
9	6,000	662.30	629.82	(32.48)	(4.9)	10.5	641.52	624.83	(16.69)	(2.6)	10.4
10	7,000	756.02	718.13	(37.89)	(5.0)	10.3	731.77	712.30	(19.47)	(2.7)	10.2
11	8,000	849.74	806.43	(43.30)	(5.1)	10.1	822.02	799.77	(22.26)	(2.7)	10.0
12	9,000	943.45	894.74	(48.72)	(5.2)	9.9	912.28	887.24	(25.04)	(2.7)	9.9
13	10,000	1,037.17	983.04	(54.13)	(5.2)	9.8	1,002.53	974.71	(27.82)	(2.8)	9.7
14	15,000	1,505.76	1,424.56	(81.19)	(5.4)	9.5	1,453.80	1,412.07	(41.73)	(2.9)	9.4
15	20,000	1,974.34	1,866.08	(108.26)	(5.5)	9.3	1,905.06	1,849.42	(55.64)	(2.9)	9.2
16	25,000	2,442.93	2,307.60	(135.33)	(5.5)	9.2	2,356.33	2,286.78	(69.55)	(3.0)	9.1
17	30,000	2,911.51	2,749.12	(162.39)	(5.6)	9.2	2,807.59	2,724.13	(83.46)	(3.0)	9.1
18	35,000	3,380.10	3,190.64	(189.46)	(5.6)	9.1	3,258.86	3,161.49	(97.37)	(3.0)	9.0
19	40,000	3,848.68	3,632.16	(216.52)	(5.6)	9.1	3,710.12	3,598.84	(111.28)	(3.0)	9.0
20	45,000	4,317.27	4,073.68	(243.59)	(5.6)	9.1	4,161.39	4,036.20	(125.19)	(3.0)	9.0
21	50,000	4,785.85	4,515.20	(270.65)	(5.7)	9.0	4,612.65	4,473.55	(139.10)	(3.0)	8.9
22	60,000	5,723.02	5,398.24	(324.78)	(5.7)	9.0	5,515.18	5,348.26	(166.92)	(3.0)	8.9
23	70,000	6,660.19	6,281.28	(378.91)	(5.7)	9.0	6,417.71	6,222.97	(194.74)	(3.0)	8.9
24	80,000	7,597.36	7,164.32	(433.04)	(5.7)	9.0	7,320.24	7,097.68	(222.56)	(3.0)	8.9
25	90,000	8,534.53	8,047.36	(487.17)	(5.7)	8.9	8,222.77	7,972.39	(250.38)	(3.0)	8.9
26	100,000	9,471.70	8,930.40	(541.30)	(5.7)	8.9	9,125.30	8,847.10	(278.20)	(3.0)	8.8
27	110,000	10,408.87	9,813.44	(595.43)	(5.7)	8.9	10,027.83	9,721.81	(306.02)	(3.1)	8.8
28	120,000	11,346.04	10,696.48	(649.56)	(5.7)	8.9	10,930.36	10,596.52	(333.84)	(3.1)	8.8
29	130,000	12,283.21	11,579.52	(703.69)	(5.7)	8.9	11,832.89	11,471.23	(361.66)	(3.1)	8.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	0.085586	0.082234	0.082122	0.081401
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.007331	0.005270	0.007331	0.005270
System Access	100.00	100.00	100.00	100.00

Schedule F-4

Primary Energy-only GP (Voltage Level 2)
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	150.57	146.50	(4.07)	(2.7)	29.3	148.83	146.08	(2.75)	(1.8)	29.2
2	1,000	201.13	193.00	(8.13)	(4.0)	19.3	197.67	192.17	(5.50)	(2.8)	19.2
3	1,500	251.70	239.50	(12.20)	(4.8)	16.0	246.50	238.25	(8.25)	(3.3)	15.9
4	2,000	302.26	286.00	(16.27)	(5.4)	14.3	295.33	284.33	(11.00)	(3.7)	14.2
5	2,500	352.83	332.50	(20.33)	(5.8)	13.3	344.17	330.41	(13.76)	(4.0)	13.2
6	3,000	403.39	378.99	(24.40)	(6.0)	12.6	393.00	376.50	(16.51)	(4.2)	12.5
7	4,000	504.52	471.99	(32.53)	(6.4)	11.8	490.67	468.66	(22.01)	(4.5)	11.7
8	5,000	605.66	564.99	(40.67)	(6.7)	11.3	588.34	560.83	(27.51)	(4.7)	11.2
9	6,000	706.79	657.99	(48.80)	(6.9)	11.0	686.00	652.99	(33.01)	(4.8)	10.9
10	7,000	807.92	750.99	(56.93)	(7.0)	10.7	783.67	745.16	(38.51)	(4.9)	10.6
11	8,000	909.05	843.98	(65.06)	(7.2)	10.5	881.34	837.32	(44.02)	(5.0)	10.5
12	9,000	1,010.18	936.98	(73.20)	(7.2)	10.4	979.00	929.49	(49.52)	(5.1)	10.3
13	10,000	1,111.31	1,029.98	(81.33)	(7.3)	10.3	1,076.67	1,021.65	(55.02)	(5.1)	10.2
14	15,000	1,616.97	1,494.97	(122.00)	(7.5)	10.0	1,565.01	1,482.48	(82.53)	(5.3)	9.9
15	20,000	2,122.62	1,959.96	(162.66)	(7.7)	9.8	2,053.34	1,943.30	(110.04)	(5.4)	9.7
16	25,000	2,628.28	2,424.95	(203.33)	(7.7)	9.7	2,541.68	2,404.13	(137.55)	(5.4)	9.6
17	30,000	3,133.93	2,889.94	(243.99)	(7.8)	9.6	3,030.01	2,864.95	(165.06)	(5.4)	9.5
18	35,000	3,639.59	3,354.93	(284.66)	(7.8)	9.6	3,518.35	3,325.78	(192.57)	(5.5)	9.5
19	40,000	4,145.24	3,819.92	(325.32)	(7.8)	9.5	4,006.68	3,786.60	(220.08)	(5.5)	9.5
20	45,000	4,650.90	4,284.91	(365.99)	(7.9)	9.5	4,495.02	4,247.43	(247.59)	(5.5)	9.4
21	50,000	5,156.55	4,749.90	(406.65)	(7.9)	9.5	4,983.35	4,708.25	(275.10)	(5.5)	9.4
22	60,000	6,167.86	5,679.88	(487.98)	(7.9)	9.5	5,960.02	5,629.90	(330.12)	(5.5)	9.4
23	70,000	7,179.17	6,609.86	(569.31)	(7.9)	9.4	6,936.69	6,551.55	(385.14)	(5.6)	9.4
24	80,000	8,190.48	7,539.84	(650.64)	(7.9)	9.4	7,913.36	7,473.20	(440.16)	(5.6)	9.3
25	90,000	9,201.79	8,469.82	(731.97)	(8.0)	9.4	8,890.03	8,394.85	(495.18)	(5.6)	9.3
26	100,000	10,213.10	9,399.80	(813.30)	(8.0)	9.4	9,866.70	9,316.50	(550.20)	(5.6)	9.3
27	110,000	11,224.41	10,329.78	(894.63)	(8.0)	9.4	10,843.37	10,238.15	(605.22)	(5.6)	9.3
28	120,000	12,235.72	11,259.76	(975.96)	(8.0)	9.4	11,820.04	11,159.80	(660.24)	(5.6)	9.3
29	130,000	13,247.03	12,189.74	(1,057.29)	(8.0)	9.4	12,796.71	12,081.45	(715.26)	(5.6)	9.3

	Summer Present	Summer Proposed	Winter Present	Winter Proposed
Power Supply Charges				
All kWh/mth	0.089586	0.084414	0.086122	0.083581
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.010745	0.007784	0.010745	0.007784
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 20 of 53
Witness: LMCollins
Date: May 2018

Primary Energy-only GP (Voltage Level 2)
Education Provision GEI
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	150.30	146.24	(4.06)	(2.7)	29.2	148.57	145.83	(2.74)	(1.8)	29.2
2	1,000	200.60	192.48	(8.12)	(4.0)	19.2	197.14	191.65	(5.49)	(2.8)	19.2
3	1,500	250.90	238.73	(12.18)	(4.9)	15.9	245.71	237.48	(8.23)	(3.3)	15.8
4	2,000	301.20	284.97	(16.23)	(5.4)	14.2	294.27	283.30	(10.97)	(3.7)	14.2
5	2,500	351.50	331.21	(20.29)	(5.8)	13.2	342.84	329.13	(13.72)	(4.0)	13.2
6	3,000	401.80	377.45	(24.35)	(6.1)	12.6	391.41	374.95	(16.46)	(4.2)	12.5
7	4,000	502.40	469.94	(32.47)	(6.5)	11.7	488.55	466.60	(21.94)	(4.5)	11.7
8	5,000	603.01	562.42	(40.59)	(6.7)	11.2	585.69	558.26	(27.43)	(4.7)	11.2
9	6,000	703.61	654.90	(48.70)	(6.9)	10.9	682.82	649.91	(32.92)	(4.8)	10.8
10	7,000	804.21	747.39	(56.82)	(7.1)	10.7	779.96	741.56	(38.40)	(4.9)	10.6
11	8,000	904.81	839.87	(64.94)	(7.2)	10.5	877.10	833.21	(43.89)	(5.0)	10.4
12	9,000	1,005.41	932.36	(73.05)	(7.3)	10.4	974.23	924.86	(49.37)	(5.1)	10.3
13	10,000	1,106.01	1,024.84	(81.17)	(7.3)	10.2	1,071.37	1,016.51	(54.86)	(5.1)	10.2
14	15,000	1,609.02	1,487.26	(121.76)	(7.6)	9.9	1,557.06	1,474.77	(82.29)	(5.3)	9.8
15	20,000	2,112.02	1,949.68	(162.34)	(7.7)	9.7	2,042.74	1,933.02	(109.72)	(5.4)	9.7
16	25,000	2,615.03	2,412.10	(202.93)	(7.8)	9.6	2,528.43	2,391.28	(137.15)	(5.4)	9.6
17	30,000	3,118.03	2,874.52	(243.51)	(7.8)	9.6	3,014.11	2,849.53	(164.58)	(5.5)	9.5
18	35,000	3,621.04	3,336.94	(284.10)	(7.8)	9.5	3,499.80	3,307.79	(192.01)	(5.5)	9.5
19	40,000	4,124.04	3,799.36	(324.68)	(7.9)	9.5	3,985.48	3,766.04	(219.44)	(5.5)	9.4
20	45,000	4,627.05	4,261.78	(365.27)	(7.9)	9.5	4,471.17	4,224.30	(246.87)	(5.5)	9.4
21	50,000	5,130.05	4,724.20	(405.85)	(7.9)	9.4	4,956.85	4,682.55	(274.30)	(5.5)	9.4
22	60,000	6,136.06	5,649.04	(487.02)	(7.9)	9.4	5,928.22	5,599.06	(329.16)	(5.6)	9.3
23	70,000	7,142.07	6,573.88	(568.19)	(8.0)	9.4	6,899.59	6,515.57	(384.02)	(5.6)	9.3
24	80,000	8,148.08	7,498.72	(649.36)	(8.0)	9.4	7,870.96	7,432.08	(438.88)	(5.6)	9.3
25	90,000	9,154.09	8,423.56	(730.53)	(8.0)	9.4	8,842.33	8,348.59	(493.74)	(5.6)	9.3
26	100,000	10,160.10	9,348.40	(811.70)	(8.0)	9.3	9,813.70	9,265.10	(548.60)	(5.6)	9.3
27	110,000	11,166.11	10,273.24	(892.87)	(8.0)	9.3	10,785.07	10,181.61	(603.46)	(5.6)	9.3
28	120,000	12,172.12	11,198.08	(974.04)	(8.0)	9.3	11,756.44	11,098.12	(658.32)	(5.6)	9.2
29	130,000	13,178.13	12,122.92	(1,055.21)	(8.0)	9.3	12,727.81	12,014.63	(713.18)	(5.6)	9.2

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	0.089586	0.084414	0.086122	0.083581
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.010215	0.007270	0.010215	0.007270
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 21 of 53
Witness: LMCollins
Date: May 2018

Primary Energy-only GP (Voltage Level 3)
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	159.49	155.37	(4.13)	(2.6)	31.1	157.76	154.95	(2.81)	(1.8)	31.0
2	1,000	218.99	210.73	(8.25)	(3.8)	21.1	215.52	209.90	(5.62)	(2.6)	21.0
3	1,500	278.48	266.10	(12.38)	(4.4)	17.7	273.28	264.85	(8.44)	(3.1)	17.7
4	2,000	337.97	321.46	(16.51)	(4.9)	16.1	331.05	319.80	(11.25)	(3.4)	16.0
5	2,500	397.47	376.83	(20.64)	(5.2)	15.1	388.81	374.75	(14.06)	(3.6)	15.0
6	3,000	456.96	432.20	(24.77)	(5.4)	14.4	446.57	429.70	(16.87)	(3.8)	14.3
7	4,000	575.95	542.93	(33.02)	(5.7)	13.6	562.09	539.60	(22.50)	(4.0)	13.5
8	5,000	694.94	653.66	(41.28)	(5.9)	13.1	677.62	649.50	(28.12)	(4.1)	13.0
9	6,000	813.92	764.39	(49.53)	(6.1)	12.7	793.14	759.39	(33.74)	(4.3)	12.7
10	7,000	932.91	875.12	(57.78)	(6.2)	12.5	908.66	869.29	(39.37)	(4.3)	12.4
11	8,000	1,051.90	985.86	(66.04)	(6.3)	12.3	1,024.18	979.19	(44.99)	(4.4)	12.2
12	9,000	1,170.88	1,096.59	(74.29)	(6.3)	12.2	1,139.71	1,089.09	(50.62)	(4.4)	12.1
13	10,000	1,289.87	1,207.32	(82.55)	(6.4)	12.1	1,255.23	1,198.99	(56.24)	(4.5)	12.0
14	15,000	1,884.81	1,760.98	(123.83)	(6.6)	11.7	1,832.85	1,748.49	(84.36)	(4.6)	11.7
15	20,000	2,479.74	2,314.64	(165.10)	(6.7)	11.6	2,410.46	2,297.98	(112.48)	(4.7)	11.5
16	25,000	3,074.68	2,868.30	(206.38)	(6.7)	11.5	2,988.08	2,847.48	(140.60)	(4.7)	11.4
17	30,000	3,669.61	3,421.96	(247.65)	(6.7)	11.4	3,565.69	3,396.97	(168.72)	(4.7)	11.3
18	35,000	4,264.55	3,975.62	(288.92)	(6.8)	11.4	4,143.31	3,946.47	(196.84)	(4.8)	11.3
19	40,000	4,859.48	4,529.28	(330.20)	(6.8)	11.3	4,720.92	4,495.96	(224.96)	(4.8)	11.2
20	45,000	5,454.42	5,082.94	(371.47)	(6.8)	11.3	5,298.54	5,045.46	(253.08)	(4.8)	11.2
21	50,000	6,049.35	5,636.60	(412.75)	(6.8)	11.3	5,876.15	5,594.95	(281.20)	(4.8)	11.2
22	60,000	7,239.22	6,743.92	(495.30)	(6.8)	11.2	7,031.38	6,693.94	(337.44)	(4.8)	11.2
23	70,000	8,429.09	7,851.24	(577.85)	(6.9)	11.2	8,186.61	7,792.93	(393.68)	(4.8)	11.1
24	80,000	9,618.96	8,958.56	(660.40)	(6.9)	11.2	9,341.84	8,891.92	(449.92)	(4.8)	11.1
25	90,000	10,808.83	10,065.88	(742.95)	(6.9)	11.2	10,497.07	9,990.91	(506.16)	(4.8)	11.1
26	100,000	11,998.70	11,173.20	(825.50)	(6.9)	11.2	11,652.30	11,089.90	(562.40)	(4.8)	11.1
27	110,000	13,188.57	12,280.52	(908.05)	(6.9)	11.2	12,807.53	12,188.89	(618.64)	(4.8)	11.1
28	120,000	14,378.44	13,387.84	(990.60)	(6.9)	11.2	13,962.76	13,287.88	(674.88)	(4.8)	11.1
29	130,000	15,568.31	14,495.16	(1,073.15)	(6.9)	11.2	15,117.99	14,386.87	(731.12)	(4.8)	11.1

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	0.100986	0.096234	0.097522	0.095401
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.017201	0.013698	0.017201	0.013698
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP (Voltage Level 3)
Education Provision GEI
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 22 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	159.23	155.11	(4.12)	(2.6)	31.0	157.50	154.69	(2.80)	(1.8)	30.9
2	1,000	218.46	210.22	(8.24)	(3.8)	21.0	214.99	209.39	(5.61)	(2.6)	20.9
3	1,500	277.69	265.33	(12.36)	(4.5)	17.7	272.49	264.08	(8.41)	(3.1)	17.6
4	2,000	336.91	320.44	(16.48)	(4.9)	16.0	329.99	318.77	(11.22)	(3.4)	15.9
5	2,500	396.14	375.55	(20.60)	(5.2)	15.0	387.48	373.46	(14.02)	(3.6)	14.9
6	3,000	455.37	430.65	(24.72)	(5.4)	14.4	444.98	428.16	(16.82)	(3.8)	14.3
7	4,000	573.83	540.87	(32.96)	(5.7)	13.5	559.97	537.54	(22.43)	(4.0)	13.4
8	5,000	692.29	651.09	(41.19)	(6.0)	13.0	674.97	646.93	(28.04)	(4.2)	12.9
9	6,000	810.74	761.31	(49.43)	(6.1)	12.7	789.96	756.31	(33.65)	(4.3)	12.6
10	7,000	929.20	871.53	(57.67)	(6.2)	12.5	904.95	865.70	(39.26)	(4.3)	12.4
11	8,000	1,047.66	981.74	(65.91)	(6.3)	12.3	1,019.94	975.08	(44.86)	(4.4)	12.2
12	9,000	1,166.11	1,091.96	(74.15)	(6.4)	12.1	1,134.94	1,084.47	(50.47)	(4.4)	12.0
13	10,000	1,284.57	1,202.18	(82.39)	(6.4)	12.0	1,249.93	1,193.85	(56.08)	(4.5)	11.9
14	15,000	1,876.86	1,753.27	(123.59)	(6.6)	11.7	1,824.90	1,740.78	(84.12)	(4.6)	11.6
15	20,000	2,469.14	2,304.36	(164.78)	(6.7)	11.5	2,399.86	2,287.70	(112.16)	(4.7)	11.4
16	25,000	3,061.43	2,855.45	(205.98)	(6.7)	11.4	2,974.83	2,834.63	(140.20)	(4.7)	11.3
17	30,000	3,653.71	3,406.54	(247.17)	(6.8)	11.4	3,549.79	3,381.55	(168.24)	(4.7)	11.3
18	35,000	4,246.00	3,957.63	(288.37)	(6.8)	11.3	4,124.76	3,928.48	(196.28)	(4.8)	11.2
19	40,000	4,838.28	4,508.72	(329.56)	(6.8)	11.3	4,699.72	4,475.40	(224.32)	(4.8)	11.2
20	45,000	5,430.57	5,059.81	(370.76)	(6.8)	11.2	5,274.69	5,022.33	(252.36)	(4.8)	11.2
21	50,000	6,022.85	5,610.90	(411.95)	(6.8)	11.2	5,849.65	5,569.25	(280.40)	(4.8)	11.1
22	60,000	7,207.42	6,713.08	(494.34)	(6.9)	11.2	6,999.58	6,663.10	(336.48)	(4.8)	11.1
23	70,000	8,391.99	7,815.26	(576.73)	(6.9)	11.2	8,149.51	7,756.95	(392.56)	(4.8)	11.1
24	80,000	9,576.56	8,917.44	(659.12)	(6.9)	11.1	9,299.44	8,850.80	(448.64)	(4.8)	11.1
25	90,000	10,761.13	10,019.62	(741.51)	(6.9)	11.1	10,449.37	9,944.65	(504.72)	(4.8)	11.0
26	100,000	11,945.70	11,121.80	(823.90)	(6.9)	11.1	11,599.30	11,038.50	(560.80)	(4.8)	11.0
27	110,000	13,130.27	12,223.98	(906.29)	(6.9)	11.1	12,749.23	12,132.35	(616.88)	(4.8)	11.0
28	120,000	14,314.84	13,326.16	(988.68)	(6.9)	11.1	13,899.16	13,226.20	(672.96)	(4.8)	11.0
29	130,000	15,499.41	14,428.34	(1,071.07)	(6.9)	11.1	15,049.09	14,320.05	(729.04)	(4.8)	11.0

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	0.100986	0.096234	0.097522	0.095401
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Distribution kWh/mth	0.016671	0.013184	0.016671	0.013184
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

Primary Demand GPD (Voltage Level 1)
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	9.54	10.86	1.31	13.8	10.9	9.16	10.32	1.16	12.6	10.3
2	110	10.48	11.92	1.44	13.8	10.8	10.06	11.33	1.27	12.7	10.3
3	120	11.41	12.99	1.58	13.8	10.8	10.96	12.35	1.39	12.7	10.3
4	130	12.35	14.05	1.71	13.8	10.8	11.85	13.36	1.51	12.7	10.3
5	140	13.28	15.12	1.84	13.8	10.8	12.75	14.37	1.62	12.7	10.3
6	150	14.22	16.19	1.97	13.9	10.8	13.65	15.38	1.74	12.7	10.3
7	200	18.89	21.51	2.63	13.9	10.8	18.13	20.44	2.32	12.8	10.2
8	250	23.56	26.84	3.28	13.9	10.7	22.61	25.51	2.90	12.8	10.2
9	300	28.23	32.17	3.94	14.0	10.7	27.09	30.57	3.48	12.8	10.2
10	350	32.90	37.50	4.60	14.0	10.7	31.57	35.63	4.06	12.8	10.2
11	400	37.57	42.83	5.25	14.0	10.7	36.06	40.69	4.63	12.9	10.2
12	450	42.25	48.16	5.91	14.0	10.7	40.54	45.75	5.21	12.9	10.2
13	500	46.92	53.49	6.57	14.0	10.7	45.02	50.81	5.79	12.9	10.2
14	600	56.26	64.14	7.88	14.0	10.7	53.98	60.93	6.95	12.9	10.2
15	700	65.61	74.80	9.20	14.0	10.7	62.95	71.06	8.11	12.9	10.2
16	800	74.95	85.46	10.51	14.0	10.7	71.91	81.18	9.27	12.9	10.1
17	900	84.29	96.11	11.82	14.0	10.7	80.87	91.30	10.43	12.9	10.1
18	1,000	93.64	106.77	13.14	14.0	10.7	89.84	101.42	11.59	12.9	10.1
19	1,500	140.35	160.06	19.70	14.0	10.7	134.66	152.04	17.38	12.9	10.1
20	2,000	187.07	213.34	26.27	14.0	10.7	179.48	202.65	23.17	12.9	10.1
21	2,500	233.79	266.63	32.84	14.0	10.7	224.29	253.26	28.97	12.9	10.1
22	3,000	280.51	319.92	39.41	14.0	10.7	269.11	303.87	34.76	12.9	10.1
23	3,500	327.23	373.20	45.98	14.1	10.7	313.93	354.49	40.55	12.9	10.1
24	4,000	373.94	426.49	52.54	14.1	10.7	358.75	405.10	46.35	12.9	10.1
25	4,500	420.66	479.77	59.11	14.1	10.7	403.57	455.71	52.14	12.9	10.1
26	5,000	467.38	533.06	65.68	14.1	10.7	448.39	506.32	57.93	12.9	10.1
27	5,500	514.10	586.35	72.25	14.1	10.7	493.21	556.93	63.73	12.9	10.1
28	6,000	560.82	639.63	78.82	14.1	10.7	538.03	607.55	69.52	12.9	10.1
29	6,500	607.53	692.92	85.38	14.1	10.7	582.85	658.16	75.31	12.9	10.1

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	20.24	29.18	19.24	27.18
On-peak kWh/mth	0.046189	0.031439	0.036253	0.025664
Off-peak kWh/mth	0.030316	0.020376	0.032217	0.022477
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.06	0.98	1.06	0.98
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 1)
Interruptible Provision GI
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 24 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	7.63	8.94	1.31	17.2	8.9	7.52	8.68	1.16	15.4	8.7
2	110	8.37	9.81	1.44	17.3	8.9	8.25	9.53	1.27	15.4	8.7
3	120	9.11	10.69	1.58	17.3	8.9	8.98	10.37	1.39	15.5	8.6
4	130	9.85	11.56	1.71	17.3	8.9	9.72	11.22	1.51	15.5	8.6
5	140	10.60	12.44	1.84	17.4	8.9	10.45	12.07	1.62	15.5	8.6
6	150	11.34	13.31	1.97	17.4	8.9	11.18	12.92	1.74	15.5	8.6
7	200	15.05	17.68	2.63	17.5	8.8	14.84	17.16	2.32	15.6	8.6
8	250	18.76	22.05	3.28	17.5	8.8	18.50	21.40	2.90	15.7	8.6
9	300	22.48	26.42	3.94	17.5	8.8	22.16	25.64	3.48	15.7	8.5
10	350	26.19	30.79	4.60	17.6	8.8	25.82	29.88	4.06	15.7	8.5
11	400	29.90	35.16	5.25	17.6	8.8	29.48	34.11	4.63	15.7	8.5
12	450	33.62	39.53	5.91	17.6	8.8	33.14	38.35	5.21	15.7	8.5
13	500	37.33	43.90	6.57	17.6	8.8	36.80	42.59	5.79	15.7	8.5
14	600	44.75	52.64	7.88	17.6	8.8	44.12	51.07	6.95	15.8	8.5
15	700	52.18	61.38	9.20	17.6	8.8	51.44	59.55	8.11	15.8	8.5
16	800	59.61	70.12	10.51	17.6	8.8	58.76	68.03	9.27	15.8	8.5
17	900	67.03	78.85	11.82	17.6	8.8	66.08	76.51	10.43	15.8	8.5
18	1,000	74.46	87.59	13.14	17.6	8.8	73.40	84.99	11.59	15.8	8.5
19	1,500	111.59	131.29	19.70	17.7	8.8	110.00	127.38	17.38	15.8	8.5
20	2,000	148.72	174.99	26.27	17.7	8.7	146.60	169.77	23.17	15.8	8.5
21	2,500	185.84	218.68	32.84	17.7	8.7	183.20	212.17	28.97	15.8	8.5
22	3,000	222.97	262.38	39.41	17.7	8.7	219.80	254.56	34.76	15.8	8.5
23	3,500	260.10	306.08	45.98	17.7	8.7	256.40	296.95	40.55	15.8	8.5
24	4,000	297.23	349.78	52.54	17.7	8.7	293.00	339.34	46.35	15.8	8.5
25	4,500	334.36	393.47	59.11	17.7	8.7	329.60	381.74	52.14	15.8	8.5
26	5,000	371.49	437.17	65.68	17.7	8.7	366.20	424.13	57.93	15.8	8.5
27	5,500	408.62	480.87	72.25	17.7	8.7	402.80	466.52	63.73	15.8	8.5
28	6,000	445.75	524.56	78.82	17.7	8.7	439.40	508.92	69.52	15.8	8.5
29	6,500	482.88	568.26	85.38	17.7	8.7	476.00	551.31	75.31	15.8	8.5

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	13.24	22.18	13.24	21.18
On-peak kWh/mth	0.046189	0.031439	0.036253	0.025664
Off-peak kWh/mth	0.030316	0.020376	0.032217	0.022477
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.06	0.98	1.06	0.98
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 1)
Education Provision GEI
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 25 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	9.51	10.83	1.31	13.8	10.8	9.13	10.29	1.16	12.7	10.3
2	110	10.45	11.89	1.44	13.8	10.8	10.03	11.30	1.27	12.7	10.3
3	120	11.38	12.95	1.57	13.8	10.8	10.92	12.31	1.39	12.7	10.3
4	130	12.31	14.01	1.71	13.9	10.8	11.81	13.32	1.50	12.7	10.2
5	140	13.24	15.08	1.84	13.9	10.8	12.71	14.33	1.62	12.7	10.2
6	150	14.17	16.14	1.97	13.9	10.8	13.60	15.34	1.74	12.8	10.2
7	200	18.83	21.45	2.62	13.9	10.7	18.07	20.38	2.31	12.8	10.2
8	250	23.49	26.76	3.28	14.0	10.7	22.54	25.43	2.89	12.8	10.2
9	300	28.14	32.08	3.94	14.0	10.7	27.00	30.47	3.47	12.9	10.2
10	350	32.80	37.39	4.59	14.0	10.7	31.47	35.52	4.05	12.9	10.1
11	400	37.46	42.70	5.25	14.0	10.7	35.94	40.56	4.63	12.9	10.1
12	450	42.11	48.02	5.90	14.0	10.7	40.40	45.61	5.21	12.9	10.1
13	500	46.77	53.33	6.56	14.0	10.7	44.87	50.66	5.78	12.9	10.1
14	600	56.08	63.95	7.87	14.0	10.7	53.81	60.75	6.94	12.9	10.1
15	700	65.40	74.58	9.18	14.0	10.7	62.74	70.84	8.10	12.9	10.1
16	800	74.71	85.21	10.49	14.0	10.7	71.67	80.93	9.25	12.9	10.1
17	900	84.03	95.83	11.81	14.1	10.6	80.61	91.02	10.41	12.9	10.1
18	1,000	93.34	106.46	13.12	14.1	10.6	89.54	101.11	11.57	12.9	10.1
19	1,500	139.91	159.59	19.68	14.1	10.6	134.21	151.57	17.35	12.9	10.1
20	2,000	186.48	212.72	26.24	14.1	10.6	178.88	202.02	23.14	12.9	10.1
21	2,500	233.05	265.84	32.79	14.1	10.6	223.55	252.48	28.92	12.9	10.1
22	3,000	279.62	318.97	39.35	14.1	10.6	268.23	302.93	34.71	12.9	10.1
23	3,500	326.19	372.10	45.91	14.1	10.6	312.90	353.39	40.49	12.9	10.1
24	4,000	372.76	425.23	52.47	14.1	10.6	357.57	403.84	46.27	12.9	10.1
25	4,500	419.33	478.36	59.03	14.1	10.6	402.24	454.30	52.06	12.9	10.1
26	5,000	465.90	531.49	65.59	14.1	10.6	446.91	504.75	57.84	12.9	10.1
27	5,500	512.47	584.62	72.15	14.1	10.6	491.58	555.21	63.63	12.9	10.1
28	6,000	559.04	637.75	78.71	14.1	10.6	536.25	605.66	69.41	12.9	10.1
29	6,500	605.61	690.88	85.27	14.1	10.6	580.92	656.12	75.20	12.9	10.1

	Summer Present	Summer Proposed	Winter Present	Winter Proposed
Power Supply Charges				
On-peak kW/mth	20.24	29.18	19.24	27.18
On-peak kWh/mth	0.046189	0.031439	0.036253	0.025664
Off-peak kWh/mth	0.030316	0.020376	0.032217	0.022477
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.06	0.98	1.06	0.98
Distribution kWh/mth	(0.000296)	(0.000314)	(0.000296)	(0.000314)
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 2)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	10.25	11.81	1.56	15.2	11.8	9.87	11.28	1.41	14.3	11.3
2	110	11.25	12.97	1.72	15.3	11.8	10.83	12.38	1.55	14.3	11.3
3	120	12.26	14.13	1.87	15.3	11.8	11.80	13.49	1.69	14.3	11.2
4	130	13.26	15.29	2.03	15.3	11.8	12.77	14.60	1.83	14.3	11.2
5	140	14.27	16.45	2.19	15.3	11.8	13.74	15.71	1.97	14.3	11.2
6	150	15.27	17.62	2.34	15.3	11.7	14.70	16.81	2.11	14.4	11.2
7	200	20.30	23.42	3.12	15.4	11.7	19.54	22.35	2.81	14.4	11.2
8	250	25.32	29.23	3.91	15.4	11.7	24.37	27.89	3.52	14.4	11.2
9	300	30.34	35.03	4.69	15.4	11.7	29.20	33.43	4.22	14.5	11.1
10	350	35.37	40.84	5.47	15.5	11.7	34.04	38.96	4.93	14.5	11.1
11	400	40.39	46.64	6.25	15.5	11.7	38.87	44.50	5.63	14.5	11.1
12	450	45.41	52.45	7.03	15.5	11.7	43.71	50.04	6.33	14.5	11.1
13	500	50.44	58.25	7.81	15.5	11.7	48.54	55.58	7.04	14.5	11.1
14	600	60.49	69.86	9.37	15.5	11.6	58.21	66.65	8.44	14.5	11.1
15	700	70.53	81.47	10.94	15.5	11.6	67.88	77.73	9.85	14.5	11.1
16	800	80.58	93.08	12.50	15.5	11.6	77.54	88.80	11.26	14.5	11.1
17	900	90.63	104.69	14.06	15.5	11.6	87.21	99.88	12.67	14.5	11.1
18	1,000	100.68	116.30	15.62	15.5	11.6	96.88	110.95	14.07	14.5	11.1
19	1,500	150.92	174.35	23.43	15.5	11.6	145.22	166.33	21.11	14.5	11.1
20	2,000	201.15	232.40	31.25	15.5	11.6	193.56	221.71	28.15	14.5	11.1
21	2,500	251.39	290.45	39.06	15.5	11.6	241.90	277.08	35.18	14.5	11.1
22	3,000	301.63	348.50	46.87	15.5	11.6	290.24	332.46	42.22	14.5	11.1
23	3,500	351.87	406.55	54.68	15.5	11.6	338.58	387.83	49.26	14.5	11.1
24	4,000	402.11	464.60	62.49	15.5	11.6	386.92	443.21	56.29	14.5	11.1
25	4,500	452.35	522.65	70.30	15.5	11.6	435.26	498.59	63.33	14.6	11.1
26	5,000	502.59	580.70	78.12	15.5	11.6	483.60	553.96	70.37	14.6	11.1
27	5,500	552.82	638.75	85.93	15.5	11.6	531.93	609.34	77.41	14.6	11.1
28	6,000	603.06	696.80	93.74	15.5	11.6	580.27	664.72	84.44	14.6	11.1
29	6,500	653.30	754.85	101.55	15.5	11.6	628.61	720.09	91.48	14.6	11.1

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	21.24	31.31	20.24	29.31
On-peak kWh/mth	0.048189	0.032529	0.038253	0.026754
Off-peak kWh/mth	0.032316	0.021466	0.034217	0.023567
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.90	1.93	1.90	1.93
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 27 of 53
Witness: LMCollins
Date: May 2018

Primary Demand GPD (Voltage Level 2)
Interruptible Provision GI
Bundled Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	8.33	9.89	1.56	18.8	9.9	8.22	9.63	1.41	17.1	9.6
2	110	9.14	10.86	1.72	18.8	9.9	9.03	10.57	1.55	17.2	9.6
3	120	9.96	11.83	1.87	18.8	9.9	9.83	11.52	1.69	17.2	9.6
4	130	10.77	12.80	2.03	18.9	9.8	10.63	12.46	1.83	17.2	9.6
5	140	11.58	13.77	2.19	18.9	9.8	11.43	13.40	1.97	17.2	9.6
6	150	12.39	14.74	2.34	18.9	9.8	12.24	14.35	2.11	17.3	9.6
7	200	16.46	19.58	3.12	19.0	9.8	16.25	19.06	2.81	17.3	9.5
8	250	20.52	24.43	3.91	19.0	9.8	20.26	23.78	3.52	17.4	9.5
9	300	24.59	29.28	4.69	19.1	9.8	24.27	28.49	4.22	17.4	9.5
10	350	28.65	34.12	5.47	19.1	9.7	28.28	33.21	4.93	17.4	9.5
11	400	32.72	38.97	6.25	19.1	9.7	32.30	37.93	5.63	17.4	9.5
12	450	36.78	43.81	7.03	19.1	9.7	36.31	42.64	6.33	17.4	9.5
13	500	40.85	48.66	7.81	19.1	9.7	40.32	47.36	7.04	17.5	9.5
14	600	48.98	58.35	9.37	19.1	9.7	48.34	56.79	8.44	17.5	9.5
15	700	57.11	68.05	10.94	19.1	9.7	56.37	66.22	9.85	17.5	9.5
16	800	65.24	77.74	12.50	19.2	9.7	64.39	75.65	11.26	17.5	9.5
17	900	73.37	87.43	14.06	19.2	9.7	72.42	85.08	12.67	17.5	9.5
18	1,000	81.50	97.12	15.62	19.2	9.7	80.44	94.51	14.07	17.5	9.5
19	1,500	122.15	145.58	23.43	19.2	9.7	120.56	141.67	21.11	17.5	9.4
20	2,000	162.80	194.04	31.25	19.2	9.7	160.68	188.83	28.15	17.5	9.4
21	2,500	203.45	242.51	39.06	19.2	9.7	200.80	235.99	35.18	17.5	9.4
22	3,000	244.10	290.97	46.87	19.2	9.7	240.92	283.14	42.22	17.5	9.4
23	3,500	284.75	339.43	54.68	19.2	9.7	281.04	330.30	49.26	17.5	9.4
24	4,000	325.40	387.89	62.49	19.2	9.7	321.16	377.46	56.29	17.5	9.4
25	4,500	366.05	436.35	70.30	19.2	9.7	361.28	424.61	63.33	17.5	9.4
26	5,000	406.70	484.81	78.12	19.2	9.7	401.40	471.77	70.37	17.5	9.4
27	5,500	447.34	533.27	85.93	19.2	9.7	441.52	518.93	77.41	17.5	9.4
28	6,000	487.99	581.73	93.74	19.2	9.7	481.64	566.09	84.44	17.5	9.4
29	6,500	528.64	630.19	101.55	19.2	9.7	521.76	613.24	91.48	17.5	9.4

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	14.24	24.31	14.24	23.31
On-peak kWh/mth	0.048189	0.032529	0.038253	0.026754
Off-peak kWh/mth	0.032316	0.021466	0.034217	0.023567
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.90	1.93	1.90	1.93
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 2)
Education Provision GEI
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 28 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	10.22	11.78	1.56	15.3	11.8	9.84	11.24	1.41	14.3	11.2
2	110	11.22	12.94	1.72	15.3	11.8	10.80	12.35	1.55	14.3	11.2
3	120	12.22	14.09	1.87	15.3	11.7	11.77	13.45	1.69	14.3	11.2
4	130	13.22	15.25	2.03	15.3	11.7	12.73	14.56	1.83	14.4	11.2
5	140	14.23	16.41	2.18	15.4	11.7	13.69	15.66	1.97	14.4	11.2
6	150	15.23	17.57	2.34	15.4	11.7	14.66	16.77	2.11	14.4	11.2
7	200	20.24	23.36	3.12	15.4	11.7	19.48	22.29	2.81	14.4	11.1
8	250	25.25	29.15	3.90	15.5	11.7	24.30	27.81	3.51	14.5	11.1
9	300	30.25	34.94	4.68	15.5	11.6	29.11	33.33	4.22	14.5	11.1
10	350	35.26	40.73	5.46	15.5	11.6	33.93	38.85	4.92	14.5	11.1
11	400	40.27	46.51	6.24	15.5	11.6	38.75	44.38	5.62	14.5	11.1
12	450	45.28	52.30	7.02	15.5	11.6	43.57	49.90	6.33	14.5	11.1
13	500	50.29	58.09	7.80	15.5	11.6	48.39	55.42	7.03	14.5	11.1
14	600	60.31	69.67	9.36	15.5	11.6	58.03	66.46	8.43	14.5	11.1
15	700	70.33	81.25	10.92	15.5	11.6	67.67	77.51	9.84	14.5	11.1
16	800	80.34	92.83	12.48	15.5	11.6	77.31	88.55	11.24	14.5	11.1
17	900	90.36	104.41	14.04	15.5	11.6	86.94	99.59	12.65	14.5	11.1
18	1,000	100.38	115.99	15.61	15.5	11.6	96.58	110.64	14.06	14.6	11.1
19	1,500	150.47	173.88	23.41	15.6	11.6	144.77	165.86	21.08	14.6	11.1
20	2,000	200.56	231.77	31.21	15.6	11.6	192.97	221.08	28.11	14.6	11.1
21	2,500	250.65	289.67	39.01	15.6	11.6	241.16	276.30	35.14	14.6	11.1
22	3,000	300.74	347.56	46.82	15.6	11.6	289.35	331.52	42.17	14.6	11.1
23	3,500	350.83	405.45	54.62	15.6	11.6	337.54	386.74	49.20	14.6	11.0
24	4,000	400.92	463.34	62.42	15.6	11.6	385.73	441.96	56.22	14.6	11.0
25	4,500	451.02	521.24	70.22	15.6	11.6	433.92	497.17	63.25	14.6	11.0
26	5,000	501.11	579.13	78.03	15.6	11.6	482.12	552.39	70.28	14.6	11.0
27	5,500	551.20	637.02	85.83	15.6	11.6	530.31	607.61	77.31	14.6	11.0
28	6,000	601.29	694.92	93.63	15.6	11.6	578.50	662.83	84.33	14.6	11.0
29	6,500	651.38	752.81	101.43	15.6	11.6	626.69	718.05	91.36	14.6	11.0

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	21.24	31.31	20.24	29.31
On-peak kWh/mth	0.048189	0.032529	0.038253	0.026754
Off-peak kWh/mth	0.032316	0.021466	0.034217	0.023567
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.90	1.93	1.90	1.93
Distribution kWh/mth	(0.000296)	(0.000314)	(0.000296)	(0.000314)
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 3)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	11.72	13.54	1.81	15.4	13.5	11.34	13.00	1.66	14.6	13.0
2	110	12.88	14.87	1.99	15.5	13.5	12.46	14.28	1.82	14.6	13.0
3	120	14.03	16.20	2.17	15.5	13.5	13.57	15.56	1.99	14.6	13.0
4	130	15.18	17.54	2.35	15.5	13.5	14.69	16.84	2.15	14.7	13.0
5	140	16.33	18.87	2.53	15.5	13.5	15.80	18.12	2.32	14.7	12.9
6	150	17.49	20.20	2.72	15.5	13.5	16.92	19.40	2.48	14.7	12.9
7	200	23.25	26.87	3.62	15.6	13.4	22.49	25.80	3.31	14.7	12.9
8	250	29.01	33.54	4.53	15.6	13.4	28.06	32.20	4.14	14.8	12.9
9	300	34.77	40.21	5.43	15.6	13.4	33.63	38.60	4.97	14.8	12.9
10	350	40.54	46.87	6.34	15.6	13.4	39.21	45.00	5.80	14.8	12.9
11	400	46.30	53.54	7.24	15.6	13.4	44.78	51.40	6.62	14.8	12.9
12	450	52.06	60.21	8.15	15.7	13.4	50.35	57.80	7.45	14.8	12.8
13	500	57.82	66.88	9.05	15.7	13.4	55.92	64.20	8.28	14.8	12.8
14	600	69.35	80.21	10.86	15.7	13.4	67.07	77.00	9.93	14.8	12.8
15	700	80.87	93.55	12.67	15.7	13.4	78.21	89.80	11.59	14.8	12.8
16	800	92.40	106.88	14.49	15.7	13.4	89.36	102.60	13.25	14.8	12.8
17	900	103.92	120.22	16.30	15.7	13.4	100.50	115.40	14.90	14.8	12.8
18	1,000	115.45	133.55	18.11	15.7	13.4	111.65	128.21	16.56	14.8	12.8
19	1,500	173.07	200.23	27.16	15.7	13.3	167.37	192.21	24.84	14.8	12.8
20	2,000	230.69	266.91	36.21	15.7	13.3	223.10	256.21	33.12	14.8	12.8
21	2,500	288.31	333.58	45.27	15.7	13.3	278.82	320.21	41.39	14.8	12.8
22	3,000	345.94	400.26	54.32	15.7	13.3	334.54	384.22	49.67	14.8	12.8
23	3,500	403.56	466.93	63.37	15.7	13.3	390.27	448.22	57.95	14.8	12.8
24	4,000	461.18	533.61	72.43	15.7	13.3	445.99	512.22	66.23	14.9	12.8
25	4,500	518.81	600.29	81.48	15.7	13.3	501.71	576.22	74.51	14.9	12.8
26	5,000	576.43	666.96	90.54	15.7	13.3	557.44	640.23	82.79	14.9	12.8
27	5,500	634.05	733.64	99.59	15.7	13.3	613.16	704.23	91.07	14.9	12.8
28	6,000	691.67	800.32	108.64	15.7	13.3	668.89	768.23	99.35	14.9	12.8
29	6,500	749.30	866.99	117.70	15.7	13.3	724.61	832.23	107.63	14.9	12.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	22.24	33.58	21.24	31.58
On-peak kWh/mth	0.053889	0.038439	0.043953	0.032664
Off-peak kWh/mth	0.038016	0.027376	0.039917	0.029477
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	4.21	3.80	4.21	3.80
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 3)
Interruptible Provision GI
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	9.81	11.62	1.81	18.5	11.6	9.70	11.36	1.66	17.1	11.4
2	110	10.77	12.76	1.99	18.5	11.6	10.65	12.47	1.82	17.1	11.3
3	120	11.73	13.90	2.17	18.5	11.6	11.60	13.59	1.99	17.1	11.3
4	130	12.69	15.04	2.35	18.6	11.6	12.55	14.70	2.15	17.1	11.3
5	140	13.65	16.18	2.53	18.6	11.6	13.50	15.82	2.32	17.2	11.3
6	150	14.61	17.33	2.72	18.6	11.6	14.45	16.94	2.48	17.2	11.3
7	200	19.41	23.03	3.62	18.7	11.5	19.20	22.51	3.31	17.2	11.3
8	250	24.22	28.74	4.53	18.7	11.5	23.95	28.09	4.14	17.3	11.2
9	300	29.02	34.45	5.43	18.7	11.5	28.70	33.67	4.97	17.3	11.2
10	350	33.82	40.16	6.34	18.7	11.5	33.45	39.25	5.80	17.3	11.2
11	400	38.63	45.87	7.24	18.8	11.5	38.20	44.83	6.62	17.3	11.2
12	450	43.43	51.58	8.15	18.8	11.5	42.95	50.41	7.45	17.3	11.2
13	500	48.23	57.29	9.05	18.8	11.5	47.70	55.98	8.28	17.4	11.2
14	600	57.84	68.70	10.86	18.8	11.5	57.21	67.14	9.93	17.4	11.2
15	700	67.45	80.12	12.67	18.8	11.4	66.71	78.30	11.59	17.4	11.2
16	800	77.05	91.54	14.49	18.8	11.4	76.21	89.45	13.25	17.4	11.2
17	900	86.66	102.96	16.30	18.8	11.4	85.71	100.61	14.90	17.4	11.2
18	1,000	96.27	114.37	18.11	18.8	11.4	95.21	111.77	16.56	17.4	11.2
19	1,500	144.30	171.46	27.16	18.8	11.4	142.71	167.55	24.84	17.4	11.2
20	2,000	192.34	228.55	36.21	18.8	11.4	190.22	223.33	33.12	17.4	11.2
21	2,500	240.37	285.64	45.27	18.8	11.4	237.72	279.12	41.39	17.4	11.2
22	3,000	288.40	342.72	54.32	18.8	11.4	285.23	334.90	49.67	17.4	11.2
23	3,500	336.44	399.81	63.37	18.8	11.4	332.73	390.68	57.95	17.4	11.2
24	4,000	384.47	456.90	72.43	18.8	11.4	380.24	446.47	66.23	17.4	11.2
25	4,500	432.50	513.99	81.48	18.8	11.4	427.74	502.25	74.51	17.4	11.2
26	5,000	480.54	571.07	90.54	18.8	11.4	475.25	558.03	82.79	17.4	11.2
27	5,500	528.57	628.16	99.59	18.8	11.4	522.75	613.82	91.07	17.4	11.2
28	6,000	576.61	685.25	108.64	18.8	11.4	570.26	669.60	99.35	17.4	11.2
29	6,500	624.64	742.34	117.70	18.8	11.4	617.76	725.38	107.63	17.4	11.2

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	15.24	26.58	15.24	25.58
On-peak kWh/mth	0.053889	0.038439	0.043953	0.032664
Off-peak kWh/mth	0.038016	0.027376	0.039917	0.029477
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	4.21	3.80	4.21	3.80
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 3)
Education Provision GEI
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 31 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	11.69	13.50	1.81	15.5	13.5	11.32	12.97	1.65	14.6	13.0
2	110	12.84	14.83	1.99	15.5	13.5	12.43	14.25	1.82	14.6	13.0
3	120	13.99	16.16	2.17	15.5	13.5	13.54	15.52	1.98	14.7	12.9
4	130	15.14	17.50	2.35	15.5	13.5	14.65	16.80	2.15	14.7	12.9
5	140	16.29	18.83	2.53	15.5	13.4	15.76	18.08	2.32	14.7	12.9
6	150	17.44	20.16	2.71	15.6	13.4	16.87	19.35	2.48	14.7	12.9
7	200	23.19	26.81	3.62	15.6	13.4	22.43	25.74	3.31	14.7	12.9
8	250	28.94	33.46	4.52	15.6	13.4	27.99	32.12	4.13	14.8	12.8
9	300	34.68	40.11	5.43	15.6	13.4	33.55	38.51	4.96	14.8	12.8
10	350	40.43	46.76	6.33	15.7	13.4	39.10	44.89	5.79	14.8	12.8
11	400	46.18	53.42	7.24	15.7	13.4	44.66	51.28	6.62	14.8	12.8
12	450	51.93	60.07	8.14	15.7	13.3	50.22	57.66	7.44	14.8	12.8
13	500	57.67	66.72	9.04	15.7	13.3	55.78	64.05	8.27	14.8	12.8
14	600	69.17	80.02	10.85	15.7	13.3	66.89	76.81	9.92	14.8	12.8
15	700	80.66	93.33	12.66	15.7	13.3	78.01	89.58	11.58	14.8	12.8
16	800	92.16	106.63	14.47	15.7	13.3	89.12	102.35	13.23	14.8	12.8
17	900	103.65	119.93	16.28	15.7	13.3	100.24	115.12	14.89	14.9	12.8
18	1,000	115.15	133.24	18.09	15.7	13.3	111.35	127.89	16.54	14.9	12.8
19	1,500	172.62	199.76	27.13	15.7	13.3	166.93	191.74	24.81	14.9	12.8
20	2,000	230.10	266.28	36.18	15.7	13.3	222.50	255.58	33.08	14.9	12.8
21	2,500	287.57	332.80	45.22	15.7	13.3	278.08	319.43	41.35	14.9	12.8
22	3,000	345.05	399.32	54.27	15.7	13.3	333.65	383.27	49.62	14.9	12.8
23	3,500	402.52	465.84	63.31	15.7	13.3	389.23	447.12	57.89	14.9	12.8
24	4,000	460.00	532.35	72.36	15.7	13.3	444.81	510.97	66.16	14.9	12.8
25	4,500	517.47	598.87	81.40	15.7	13.3	500.38	574.81	74.43	14.9	12.8
26	5,000	574.95	665.39	90.45	15.7	13.3	555.96	638.66	82.70	14.9	12.8
27	5,500	632.42	731.91	99.49	15.7	13.3	611.53	702.50	90.97	14.9	12.8
28	6,000	689.90	798.43	108.53	15.7	13.3	667.11	766.35	99.24	14.9	12.8
29	6,500	747.37	864.95	117.58	15.7	13.3	722.69	830.19	107.51	14.9	12.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	22.24	33.58	21.24	31.58
On-peak kWh/mth	0.053889	0.038439	0.043953	0.032664
Off-peak kWh/mth	0.038016	0.027376	0.039917	0.029477
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	4.21	3.80	4.21	3.80
Distribution kWh/mth	(0.000296)	(0.000314)	(0.000296)	(0.000314)
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy Intensive EIP (Voltage Level 1)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 32 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Increase Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	6.40	6.80	0.40	6.2	6.8	5.64	5.77	0.12	2.2	5.8
2	110	7.02	7.46	0.44	6.2	6.8	6.19	6.32	0.13	2.2	5.7
3	120	7.64	8.12	0.48	6.2	6.8	6.73	6.88	0.15	2.2	5.7
4	130	8.26	8.78	0.51	6.2	6.8	7.28	7.44	0.16	2.2	5.7
5	140	8.88	9.44	0.55	6.2	6.7	7.82	7.99	0.17	2.2	5.7
6	150	9.50	10.10	0.59	6.2	6.7	8.36	8.55	0.18	2.2	5.7
7	200	12.60	13.40	0.79	6.3	6.7	11.09	11.33	0.24	2.2	5.7
8	250	15.70	16.69	0.99	6.3	6.7	13.81	14.11	0.31	2.2	5.6
9	300	18.81	19.99	1.19	6.3	6.7	16.53	16.90	0.37	2.2	5.6
10	350	21.91	23.29	1.39	6.3	6.7	19.25	19.68	0.43	2.2	5.6
11	400	25.01	26.59	1.58	6.3	6.6	21.97	22.46	0.49	2.2	5.6
12	450	28.11	29.89	1.78	6.3	6.6	24.69	25.24	0.55	2.2	5.6
13	500	31.21	33.19	1.98	6.3	6.6	27.42	28.03	0.61	2.2	5.6
14	600	37.41	39.79	2.38	6.3	6.6	32.86	33.59	0.73	2.2	5.6
15	700	43.61	46.38	2.77	6.4	6.6	38.30	39.16	0.86	2.2	5.6
16	800	49.81	52.98	3.17	6.4	6.6	43.74	44.72	0.98	2.2	5.6
17	900	56.02	59.58	3.56	6.4	6.6	49.19	50.29	1.10	2.2	5.6
18	1,000	62.22	66.18	3.96	6.4	6.6	54.63	55.85	1.22	2.2	5.6
19	1,500	93.23	99.16	5.94	6.4	6.6	81.85	83.68	1.84	2.2	5.6
20	2,000	124.24	132.15	7.92	6.4	6.6	109.06	111.51	2.45	2.2	5.6
21	2,500	155.25	165.14	9.90	6.4	6.6	136.28	139.34	3.06	2.2	5.6
22	3,000	186.25	198.13	11.88	6.4	6.6	163.49	167.16	3.67	2.2	5.6
23	3,500	217.26	231.12	13.86	6.4	6.6	190.71	194.99	4.28	2.2	5.6
24	4,000	248.27	264.11	15.83	6.4	6.6	217.92	222.82	4.90	2.2	5.6
25	4,500	279.28	297.09	17.81	6.4	6.6	245.14	250.64	5.51	2.2	5.6
26	5,000	310.29	330.08	19.79	6.4	6.6	272.35	278.47	6.12	2.2	5.6
27	5,500	341.30	363.07	21.77	6.4	6.6	299.57	306.30	6.73	2.2	5.6
28	6,000	372.31	396.06	23.75	6.4	6.6	326.78	334.13	7.34	2.2	5.6
29	6,500	403.32	429.05	25.73	6.4	6.6	354.00	361.95	7.96	2.2	5.6

	Summer Present	Summer Proposed	Winter Present	Winter Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
High/On-peak kWh/mth	0.083610	0.092688	0.078264	0.088836
Mid-peak kWh/mth	0.077926	0.086084	0.062702	0.069925
Low-peak kWh/mth	0.063948	0.069221	-	-
Off-peak kWh/mth	0.046934	0.048882	0.048531	0.049146
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.06	0.98	1.06	0.98
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

EIP Load Profile		
Load Factor	50%	
	Summer	Winter
Highpk kWh	5%	5%
Midpk kWh	5%	5%
Lowpk kWh	47%	0%
Offpk kWh	43%	90%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy Intensive EIP (Voltage Level 2)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	7.13	8.06	0.93	13.0	8.1	6.37	7.03	0.65	10.2	7.0
2	110	7.83	8.84	1.02	13.0	8.0	6.99	7.71	0.72	10.3	7.0
3	120	8.52	9.63	1.11	13.0	8.0	7.61	8.39	0.78	10.3	7.0
4	130	9.21	10.42	1.20	13.1	8.0	8.23	9.07	0.85	10.3	7.0
5	140	9.90	11.20	1.30	13.1	8.0	8.84	9.76	0.91	10.3	7.0
6	150	10.60	11.99	1.39	13.1	8.0	9.46	10.44	0.98	10.3	7.0
7	200	14.06	15.92	1.85	13.2	8.0	12.55	13.85	1.31	10.4	6.9
8	250	17.53	19.84	2.31	13.2	7.9	15.63	17.26	1.63	10.4	6.9
9	300	21.00	23.77	2.78	13.2	7.9	18.72	20.68	1.96	10.5	6.9
10	350	24.46	27.70	3.24	13.2	7.9	21.81	24.09	2.28	10.5	6.9
11	400	27.93	31.63	3.70	13.3	7.9	24.89	27.50	2.61	10.5	6.9
12	450	31.39	35.56	4.17	13.3	7.9	27.98	30.92	2.94	10.5	6.9
13	500	34.86	39.49	4.63	13.3	7.9	31.07	34.33	3.26	10.5	6.9
14	600	41.79	47.35	5.56	13.3	7.9	37.24	41.15	3.92	10.5	6.9
15	700	48.72	55.21	6.48	13.3	7.9	43.41	47.98	4.57	10.5	6.9
16	800	55.66	63.06	7.41	13.3	7.9	49.59	54.81	5.22	10.5	6.9
17	900	62.59	70.92	8.33	13.3	7.9	55.76	61.63	5.87	10.5	6.8
18	1,000	69.52	78.78	9.26	13.3	7.9	61.93	68.46	6.53	10.5	6.8
19	1,500	104.18	118.07	13.89	13.3	7.9	92.80	102.59	9.79	10.5	6.8
20	2,000	138.84	157.36	18.52	13.3	7.9	123.66	136.71	13.05	10.6	6.8
21	2,500	173.50	196.65	23.15	13.3	7.9	154.53	170.84	16.31	10.6	6.8
22	3,000	208.16	235.94	27.78	13.3	7.9	185.40	204.97	19.58	10.6	6.8
23	3,500	242.82	275.23	32.41	13.3	7.9	216.26	239.10	22.84	10.6	6.8
24	4,000	277.48	314.52	37.04	13.3	7.9	247.13	273.23	26.10	10.6	6.8
25	4,500	312.14	353.81	41.67	13.3	7.9	277.99	307.36	29.36	10.6	6.8
26	5,000	346.80	393.10	46.30	13.4	7.9	308.86	341.49	32.63	10.6	6.8
27	5,500	381.46	432.39	50.93	13.4	7.9	339.72	375.61	35.89	10.6	6.8
28	6,000	416.12	471.68	55.56	13.4	7.9	370.59	409.74	39.15	10.6	6.8
29	6,500	450.78	510.97	60.19	13.4	7.9	401.46	443.87	42.41	10.6	6.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
High/On-peak kWh/mth	0.088610	0.102688	0.083264	0.098836
Mid-peak kWh/mth	0.082926	0.096084	0.067702	0.079925
Low-peak kWh/mth	0.068948	0.079221	-	-
Off-peak kWh/mth	0.051934	0.058882	0.053531	0.059146
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.90	1.93	1.90	1.93
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

EIP Load Profile		
Load Factor	50%	
	Summer	Winter
Highpk kWh	5%	5%
Midpk kWh	5%	5%
Lowpk kWh	47%	0%
Offpk kWh	43%	90%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy Intensive EIP (Voltage Level 3)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 34 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	7.23	7.97	0.74	10.2	8.0	6.48	6.94	0.46	7.1	6.9
2	110	7.94	8.75	0.81	10.2	8.0	7.10	7.61	0.51	7.2	6.9
3	120	8.64	9.52	0.88	10.2	7.9	7.73	8.29	0.55	7.2	6.9
4	130	9.35	10.30	0.96	10.2	7.9	8.36	8.96	0.60	7.2	6.9
5	140	10.05	11.08	1.03	10.2	7.9	8.99	9.63	0.65	7.2	6.9
6	150	10.75	11.86	1.10	10.3	7.9	9.61	10.31	0.69	7.2	6.9
7	200	14.27	15.74	1.47	10.3	7.9	12.75	13.68	0.92	7.2	6.8
8	250	17.79	19.63	1.84	10.3	7.9	15.89	17.05	1.15	7.3	6.8
9	300	21.30	23.51	2.21	10.4	7.8	19.03	20.41	1.39	7.3	6.8
10	350	24.82	27.40	2.57	10.4	7.8	22.17	23.78	1.62	7.3	6.8
11	400	28.34	31.28	2.94	10.4	7.8	25.30	27.15	1.85	7.3	6.8
12	450	31.86	35.17	3.31	10.4	7.8	28.44	30.52	2.08	7.3	6.8
13	500	35.37	39.05	3.68	10.4	7.8	31.58	33.89	2.31	7.3	6.8
14	600	42.41	46.82	4.41	10.4	7.8	37.86	40.63	2.77	7.3	6.8
15	700	49.44	54.59	5.15	10.4	7.8	44.13	47.37	3.23	7.3	6.8
16	800	56.48	62.36	5.88	10.4	7.8	50.41	54.10	3.70	7.3	6.8
17	900	63.51	70.13	6.62	10.4	7.8	56.68	60.84	4.16	7.3	6.8
18	1,000	70.55	77.90	7.35	10.4	7.8	62.96	67.58	4.62	7.3	6.8
19	1,500	105.72	116.75	11.03	10.4	7.8	94.34	101.27	6.93	7.3	6.8
20	2,000	140.90	155.61	14.71	10.4	7.8	125.72	134.96	9.24	7.3	6.7
21	2,500	176.07	194.46	18.39	10.4	7.8	157.10	168.65	11.55	7.4	6.7
22	3,000	211.24	233.31	22.06	10.4	7.8	188.48	202.34	13.86	7.4	6.7
23	3,500	246.42	272.16	25.74	10.4	7.8	219.86	236.03	16.17	7.4	6.7
24	4,000	281.59	311.01	29.42	10.4	7.8	251.24	269.72	18.48	7.4	6.7
25	4,500	316.77	349.86	33.10	10.4	7.8	282.62	303.41	20.79	7.4	6.7
26	5,000	351.94	388.71	36.77	10.4	7.8	314.00	337.10	23.10	7.4	6.7
27	5,500	387.12	427.56	40.45	10.4	7.8	345.38	370.79	25.41	7.4	6.7
28	6,000	422.29	466.42	44.13	10.4	7.8	376.76	404.48	27.72	7.4	6.7
29	6,500	457.46	505.27	47.80	10.4	7.8	408.14	438.17	30.03	7.4	6.7

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
High/On-peak kWh/mth	0.083310	0.096688	0.077964	0.092836
Mid-peak kWh/mth	0.077626	0.090084	0.062402	0.073925
Low-peak kWh/mth	0.063648	0.073221	-	-
Off-peak kWh/mth	0.046634	0.052882	0.048231	0.053146
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	4.21	3.80	4.21	3.80
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

EIP Load Profile		
Load Factor	50%	
	Summer	Winter
Highpk kWh	5%	5%
Midpk kWh	5%	5%
Lowpk kWh	47%	0%
Offpk kWh	43%	90%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Time-Of-Use Pilot GPTU (Voltage Level 1)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 35 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	8.89	8.86	(0.03)	(0.3)	8.9	6.81	6.91	0.10	1.4	6.9
2	110	9.76	9.73	(0.03)	(0.3)	8.8	7.47	7.58	0.11	1.4	6.9
3	120	10.63	10.59	(0.04)	(0.3)	8.8	8.13	8.25	0.12	1.5	6.9
4	130	11.50	11.46	(0.04)	(0.3)	8.8	8.79	8.92	0.13	1.5	6.9
5	140	12.37	12.33	(0.04)	(0.3)	8.8	9.45	9.59	0.14	1.5	6.9
6	150	13.24	13.19	(0.05)	(0.3)	8.8	10.12	10.26	0.15	1.5	6.8
7	200	17.58	17.52	(0.06)	(0.3)	8.8	13.42	13.62	0.20	1.5	6.8
8	250	21.93	21.85	(0.08)	(0.3)	8.7	16.73	16.97	0.25	1.5	6.8
9	300	26.27	26.18	(0.09)	(0.3)	8.7	20.03	20.33	0.30	1.5	6.8
10	350	30.62	30.51	(0.11)	(0.3)	8.7	23.34	23.68	0.34	1.5	6.8
11	400	34.97	34.85	(0.12)	(0.3)	8.7	26.64	27.03	0.39	1.5	6.8
12	450	39.31	39.18	(0.14)	(0.3)	8.7	29.95	30.39	0.44	1.5	6.8
13	500	43.66	43.51	(0.15)	(0.3)	8.7	33.25	33.74	0.49	1.5	6.7
14	600	52.35	52.17	(0.18)	(0.3)	8.7	39.86	40.45	0.59	1.5	6.7
15	700	61.04	60.83	(0.21)	(0.3)	8.7	46.47	47.16	0.69	1.5	6.7
16	800	69.73	69.49	(0.24)	(0.3)	8.7	53.08	53.87	0.79	1.5	6.7
17	900	78.42	78.15	(0.27)	(0.3)	8.7	59.69	60.58	0.89	1.5	6.7
18	1,000	87.11	86.81	(0.30)	(0.3)	8.7	66.30	67.29	0.98	1.5	6.7
19	1,500	130.57	130.12	(0.45)	(0.3)	8.7	99.35	100.83	1.48	1.5	6.7
20	2,000	174.03	173.43	(0.60)	(0.3)	8.7	132.41	134.37	1.97	1.5	6.7
21	2,500	217.49	216.73	(0.76)	(0.3)	8.7	165.46	167.92	2.46	1.5	6.7
22	3,000	260.94	260.04	(0.91)	(0.3)	8.7	198.51	201.46	2.95	1.5	6.7
23	3,500	304.40	303.34	(1.06)	(0.3)	8.7	231.56	235.00	3.44	1.5	6.7
24	4,000	347.86	346.65	(1.21)	(0.3)	8.7	264.61	268.55	3.93	1.5	6.7
25	4,500	391.32	389.96	(1.36)	(0.3)	8.7	297.66	302.09	4.43	1.5	6.7
26	5,000	434.77	433.26	(1.51)	(0.3)	8.7	330.71	335.63	4.92	1.5	6.7
27	5,500	478.23	476.57	(1.66)	(0.3)	8.7	363.76	369.17	5.41	1.5	6.7
28	6,000	521.69	519.88	(1.81)	(0.3)	8.7	396.82	402.72	5.90	1.5	6.7
29	6,500	565.15	563.18	(1.96)	(0.3)	8.7	429.87	436.26	6.39	1.5	6.7

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
High/On-peak kWh/mth	0.107723	0.113369	0.071530	0.071268
Mid-peak kWh/mth	0.100088	0.099523	0.067935	0.069224
Low-peak kWh/mth	0.082078	0.080312	-	-
Off-peak kWh/mth	0.060157	0.060042	0.059358	0.060812
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.06	0.98	1.06	0.98
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

GPTU Load Profile

	Present		Proposed	
Load Factor	50%		50%	
	Summer	Winter	Summer	Winter
Highpk kWh	14%	13%	14%	13%
Midpk kWh	18%	17%	18%	17%
Lowpk kWh	42%	0%	42%	0%
Offpk kWh	26%	70%	26%	70%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Time-Of-Use Pilot GPTU (Voltage Level 2)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 36 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Increase Amount**	**Increase Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Increase Amount**	**Increase Percent**	**Proposed Unit Cost**
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	9.52	9.52	(0.00)	(0.0)	9.5	7.44	7.57	0.13	1.7	7.6
2	110	10.45	10.45	(0.00)	(0.0)	9.5	8.16	8.31	0.14	1.7	7.6
3	120	11.39	11.39	(0.00)	(0.0)	9.5	8.89	9.04	0.15	1.7	7.5
4	130	12.32	12.32	(0.00)	(0.0)	9.5	9.61	9.78	0.17	1.7	7.5
5	140	13.25	13.25	(0.00)	(0.0)	9.5	10.34	10.52	0.18	1.7	7.5
6	150	14.18	14.18	(0.00)	(0.0)	9.5	11.06	11.25	0.19	1.7	7.5
7	200	18.84	18.84	(0.00)	(0.0)	9.4	14.68	14.94	0.26	1.8	7.5
8	250	23.50	23.50	(0.00)	(0.0)	9.4	18.30	18.62	0.32	1.8	7.4
9	300	28.16	28.16	(0.00)	(0.0)	9.4	21.92	22.31	0.39	1.8	7.4
10	350	32.83	32.83	(0.00)	(0.0)	9.4	25.54	25.99	0.45	1.8	7.4
11	400	37.49	37.49	(0.00)	(0.0)	9.4	29.16	29.68	0.51	1.8	7.4
12	450	42.15	42.15	(0.00)	(0.0)	9.4	32.78	33.36	0.58	1.8	7.4
13	500	46.81	46.81	(0.00)	(0.0)	9.4	36.40	37.04	0.64	1.8	7.4
14	600	56.13	56.13	(0.00)	(0.0)	9.4	43.64	44.41	0.77	1.8	7.4
15	700	65.45	65.45	(0.00)	(0.0)	9.4	50.88	51.78	0.90	1.8	7.4
16	800	74.77	74.77	(0.00)	(0.0)	9.3	58.12	59.15	1.03	1.8	7.4
17	900	84.09	84.09	(0.00)	(0.0)	9.3	65.36	66.52	1.16	1.8	7.4
18	1,000	93.42	93.42	(0.00)	(0.0)	9.3	72.60	73.89	1.29	1.8	7.4
19	1,500	140.02	140.02	(0.00)	(0.0)	9.3	108.81	110.73	1.93	1.8	7.4
20	2,000	186.63	186.63	(0.00)	(0.0)	9.3	145.01	147.58	2.57	1.8	7.4
21	2,500	233.24	233.24	(0.00)	(0.0)	9.3	181.21	184.42	3.21	1.8	7.4
22	3,000	279.85	279.85	(0.00)	(0.0)	9.3	217.41	221.27	3.86	1.8	7.4
23	3,500	326.46	326.45	(0.00)	(0.0)	9.3	253.61	258.11	4.50	1.8	7.4
24	4,000	373.06	373.06	(0.00)	(0.0)	9.3	289.82	294.96	5.14	1.8	7.4
25	4,500	419.67	419.67	(0.00)	(0.0)	9.3	326.02	331.80	5.78	1.8	7.4
26	5,000	466.28	466.28	(0.00)	(0.0)	9.3	362.22	368.64	6.43	1.8	7.4
27	5,500	512.89	512.88	(0.00)	(0.0)	9.3	398.42	405.49	7.07	1.8	7.4
28	6,000	559.50	559.49	(0.00)	(0.0)	9.3	434.62	442.33	7.71	1.8	7.4
29	6,500	606.10	606.10	(0.00)	(0.0)	9.3	470.83	479.18	8.35	1.8	7.4

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
High/On-peak kWh/mth	0.111723	0.117369	0.075530	0.075268
Mid-peak kWh/mth	0.104088	0.103523	0.071935	0.073224
Low-peak kWh/mth	0.086078	0.084312	-	-
Off-peak kWh/mth	0.064157	0.064042	0.063358	0.064812
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	1.90	1.93	1.90	1.93
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

GPTU Load Profile

	Present		Proposed	
Load Factor	50%		50%	
	Summer	Winter	Summer	Winter
Highpk kWh	14%	13%	14%	13%
Midpk kWh	18%	17%	18%	17%
Lowpk kWh	42%	0%	42%	0%
Offpk kWh	26%	70%	26%	70%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Time-Of-Use Pilot GPTU (Voltage Level 3)
Bundled Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 37 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	11.29	11.03	(0.26)	(2.3)	11.0	9.21	9.08	(0.13)	(1.4)	9.1
2	110	12.40	12.12	(0.29)	(2.3)	11.0	10.11	9.97	(0.15)	(1.4)	9.1
3	120	13.51	13.20	(0.31)	(2.3)	11.0	11.02	10.86	(0.16)	(1.4)	9.0
4	130	14.62	14.28	(0.34)	(2.3)	11.0	11.92	11.75	(0.17)	(1.4)	9.0
5	140	15.73	15.37	(0.36)	(2.3)	11.0	12.82	12.63	(0.18)	(1.4)	9.0
6	150	16.84	16.45	(0.39)	(2.3)	11.0	13.72	13.52	(0.20)	(1.4)	9.0
7	200	22.39	21.87	(0.52)	(2.3)	10.9	18.23	17.96	(0.26)	(1.4)	9.0
8	250	27.94	27.28	(0.65)	(2.3)	10.9	22.73	22.40	(0.33)	(1.5)	9.0
9	300	33.48	32.70	(0.78)	(2.3)	10.9	27.24	26.84	(0.40)	(1.5)	8.9
10	350	39.03	38.12	(0.91)	(2.3)	10.9	31.75	31.28	(0.46)	(1.5)	8.9
11	400	44.58	43.54	(1.04)	(2.3)	10.9	36.25	35.72	(0.53)	(1.5)	8.9
12	450	50.13	48.95	(1.17)	(2.3)	10.9	40.76	40.17	(0.59)	(1.5)	8.9
13	500	55.67	54.37	(1.30)	(2.3)	10.9	45.27	44.61	(0.66)	(1.5)	8.9
14	600	66.77	65.20	(1.56)	(2.3)	10.9	54.28	53.49	(0.79)	(1.5)	8.9
15	700	77.86	76.04	(1.82)	(2.3)	10.9	63.29	62.37	(0.92)	(1.5)	8.9
16	800	88.96	86.87	(2.08)	(2.3)	10.9	72.31	71.25	(1.06)	(1.5)	8.9
17	900	100.05	97.70	(2.35)	(2.3)	10.9	81.32	80.13	(1.19)	(1.5)	8.9
18	1,000	111.14	108.54	(2.61)	(2.3)	10.9	90.33	89.01	(1.32)	(1.5)	8.9
19	1,500	166.62	162.71	(3.91)	(2.3)	10.8	135.40	133.42	(1.98)	(1.5)	8.9
20	2,000	222.09	216.88	(5.21)	(2.3)	10.8	180.47	177.82	(2.64)	(1.5)	8.9
21	2,500	277.56	271.05	(6.52)	(2.3)	10.8	225.53	222.23	(3.30)	(1.5)	8.9
22	3,000	333.03	325.22	(7.82)	(2.3)	10.8	270.60	266.64	(3.96)	(1.5)	8.9
23	3,500	388.51	379.39	(9.12)	(2.3)	10.8	315.66	311.04	(4.62)	(1.5)	8.9
24	4,000	443.98	433.55	(10.42)	(2.3)	10.8	360.73	355.45	(5.28)	(1.5)	8.9
25	4,500	499.45	487.72	(11.73)	(2.3)	10.8	405.80	399.86	(5.94)	(1.5)	8.9
26	5,000	554.92	541.89	(13.03)	(2.3)	10.8	450.86	444.26	(6.60)	(1.5)	8.9
27	5,500	610.40	596.06	(14.33)	(2.3)	10.8	495.93	488.67	(7.26)	(1.5)	8.9
28	6,000	665.87	650.23	(15.64)	(2.3)	10.8	541.00	533.07	(7.92)	(1.5)	8.9
29	6,500	721.34	704.40	(16.94)	(2.3)	10.8	586.06	577.48	(8.58)	(1.5)	8.9

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
High/On-peak kWh/mth	0.123123	0.127369	0.086930	0.085268
Mid-peak kWh/mth	0.115488	0.113523	0.083335	0.083224
Low-peak kWh/mth	0.097478	0.094312	-	-
Off-peak kWh/mth	0.075557	0.074042	0.074758	0.074812
PSCR Factor kWh/mth	0.000800	0.000800	0.000800	0.000800
Delivery Charges				
Maximum kW/mth	4.21	3.80	4.21	3.80
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

GPTU Load Profile

	Present		Proposed	
Load Factor	50%		50%	
	Summer	Winter	Summer	Winter
Highpk kWh	14%	13%	14%	13%
Midpk kWh	18%	17%	18%	17%
Lowpk kWh	42%	0%	42%	0%
Offpk kWh	26%	70%	26%	70%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 38 of 53
Witness: LMCollins
Date: May 2018

Secondary Energy-only GS
ROA Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	250	30.65	30.99	0.34	1.1	12.4	30.65	30.99	0.34	1.1	12.4
2	500	41.30	41.98	0.68	1.6	8.4	41.30	41.98	0.68	1.6	8.4
3	750	51.95	52.97	1.02	2.0	7.1	51.95	52.97	1.02	2.0	7.1
4	1,000	62.60	63.95	1.36	2.2	6.4	62.60	63.95	1.36	2.2	6.4
5	1,500	83.90	85.93	2.03	2.4	5.7	83.90	85.93	2.03	2.4	5.7
6	2,000	105.20	107.91	2.71	2.6	5.4	105.20	107.91	2.71	2.6	5.4
7	2,500	126.50	129.89	3.39	2.7	5.2	126.50	129.89	3.39	2.7	5.2
8	3,000	147.79	151.86	4.07	2.8	5.1	147.79	151.86	4.07	2.8	5.1
9	3,500	169.09	173.84	4.75	2.8	5.0	169.09	173.84	4.75	2.8	5.0
10	4,000	190.39	195.82	5.42	2.8	4.9	190.39	195.82	5.42	2.8	4.9
11	4,500	211.69	217.79	6.10	2.9	4.8	211.69	217.79	6.10	2.9	4.8
12	5,000	232.99	239.77	6.78	2.9	4.8	232.99	239.77	6.78	2.9	4.8
13	6,000	275.59	283.72	8.14	3.0	4.7	275.59	283.72	8.14	3.0	4.7
14	7,000	318.19	327.68	9.49	3.0	4.7	318.19	327.68	9.49	3.0	4.7
15	8,000	360.78	371.63	10.85	3.0	4.6	360.78	371.63	10.85	3.0	4.6
16	9,000	403.38	415.59	12.20	3.0	4.6	403.38	415.59	12.20	3.0	4.6
17	10,000	445.98	459.54	13.56	3.0	4.6	445.98	459.54	13.56	3.0	4.6
18	15,000	658.97	679.31	20.34	3.1	4.5	658.97	679.31	20.34	3.1	4.5
19	20,000	871.96	899.08	27.12	3.1	4.5	871.96	899.08	27.12	3.1	4.5
20	25,000	1,084.95	1,118.85	33.90	3.1	4.5	1,084.95	1,118.85	33.90	3.1	4.5
21	30,000	1,297.94	1,338.62	40.68	3.1	4.5	1,297.94	1,338.62	40.68	3.1	4.5
22	35,000	1,510.93	1,558.39	47.46	3.1	4.5	1,510.93	1,558.39	47.46	3.1	4.5
23	40,000	1,723.92	1,778.16	54.24	3.1	4.4	1,723.92	1,778.16	54.24	3.1	4.4
24	45,000	1,936.91	1,997.93	61.02	3.2	4.4	1,936.91	1,997.93	61.02	3.2	4.4
25	50,000	2,149.90	2,217.70	67.80	3.2	4.4	2,149.90	2,217.70	67.80	3.2	4.4
26	55,000	2,362.89	2,437.47	74.58	3.2	4.4	2,362.89	2,437.47	74.58	3.2	4.4
27	60,000	2,575.88	2,657.24	81.36	3.2	4.4	2,575.88	2,657.24	81.36	3.2	4.4
28	65,000	2,788.87	2,877.01	88.14	3.2	4.4	2,788.87	2,877.01	88.14	3.2	4.4
29	70,000	3,001.86	3,096.78	94.92	3.2	4.4	3,001.86	3,096.78	94.92	3.2	4.4

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.042598	0.043954	0.042598	0.043954
System Access	20.00	20.00	20.00	20.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Energy-only GS
Education Provision GEI
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 39 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	250	30.47	30.80	0.33	1.1	12.3	30.47	30.80	0.33	1.1	12.3
2	500	40.95	41.60	0.66	1.6	8.3	40.95	41.60	0.66	1.6	8.3
3	750	51.42	52.40	0.98	1.9	7.0	51.42	52.40	0.98	1.9	7.0
4	1,000	61.89	63.20	1.31	2.1	6.3	61.89	63.20	1.31	2.1	6.3
5	1,500	82.84	84.80	1.97	2.4	5.7	82.84	84.80	1.97	2.4	5.7
6	2,000	103.78	106.40	2.62	2.5	5.3	103.78	106.40	2.62	2.5	5.3
7	2,500	124.73	128.00	3.28	2.6	5.1	124.73	128.00	3.28	2.6	5.1
8	3,000	145.67	149.60	3.93	2.7	5.0	145.67	149.60	3.93	2.7	5.0
9	3,500	166.62	171.20	4.59	2.8	4.9	166.62	171.20	4.59	2.8	4.9
10	4,000	187.56	192.80	5.24	2.8	4.8	187.56	192.80	5.24	2.8	4.8
11	4,500	208.51	214.40	5.90	2.8	4.8	208.51	214.40	5.90	2.8	4.8
12	5,000	229.45	236.01	6.56	2.9	4.7	229.45	236.01	6.56	2.9	4.7
13	6,000	271.34	279.21	7.87	2.9	4.7	271.34	279.21	7.87	2.9	4.7
14	7,000	313.23	322.41	9.18	2.9	4.6	313.23	322.41	9.18	2.9	4.6
15	8,000	355.12	365.61	10.49	3.0	4.6	355.12	365.61	10.49	3.0	4.6
16	9,000	397.01	408.81	11.80	3.0	4.5	397.01	408.81	11.80	3.0	4.5
17	10,000	438.90	452.01	13.11	3.0	4.5	438.90	452.01	13.11	3.0	4.5
18	15,000	648.35	668.02	19.67	3.0	4.5	648.35	668.02	19.67	3.0	4.5
19	20,000	857.80	884.02	26.22	3.1	4.4	857.80	884.02	26.22	3.1	4.4
20	25,000	1,067.25	1,100.03	32.78	3.1	4.4	1,067.25	1,100.03	32.78	3.1	4.4
21	30,000	1,276.70	1,316.03	39.33	3.1	4.4	1,276.70	1,316.03	39.33	3.1	4.4
22	35,000	1,486.15	1,532.04	45.89	3.1	4.4	1,486.15	1,532.04	45.89	3.1	4.4
23	40,000	1,695.60	1,748.04	52.44	3.1	4.4	1,695.60	1,748.04	52.44	3.1	4.4
24	45,000	1,905.05	1,964.05	59.00	3.1	4.4	1,905.05	1,964.05	59.00	3.1	4.4
25	50,000	2,114.50	2,180.05	65.55	3.1	4.4	2,114.50	2,180.05	65.55	3.1	4.4
26	55,000	2,323.95	2,396.06	72.11	3.1	4.4	2,323.95	2,396.06	72.11	3.1	4.4
27	60,000	2,533.40	2,612.06	78.66	3.1	4.4	2,533.40	2,612.06	78.66	3.1	4.4
28	65,000	2,742.85	2,828.07	85.22	3.1	4.4	2,742.85	2,828.07	85.22	3.1	4.4
29	70,000	2,952.30	3,044.07	91.77	3.1	4.3	2,952.30	3,044.07	91.77	3.1	4.3

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.041890	0.043201	0.041890	0.043201
System Access	20.00	20.00	20.00	20.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Demand GSD
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 40 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
Line	Monthly	Present Net	Proposed Net	Increase		Proposed	Present Net	Proposed Net	Increase		Proposed
No.	Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	49.53	47.83	(1.69)	(3.4)	9.6	49.53	47.83	(1.69)	(3.4)	9.6
2	1,000	69.05	65.67	(3.38)	(4.9)	6.6	69.05	65.67	(3.38)	(4.9)	6.6
3	1,500	88.58	83.50	(5.08)	(5.7)	5.6	88.58	83.50	(5.08)	(5.7)	5.6
4	2,000	108.10	101.34	(6.77)	(6.3)	5.1	108.10	101.34	(6.77)	(6.3)	5.1
5	2,500	127.63	119.17	(8.46)	(6.6)	4.8	127.63	119.17	(8.46)	(6.6)	4.8
6	3,000	147.16	137.01	(10.15)	(6.9)	4.6	147.16	137.01	(10.15)	(6.9)	4.6
7	3,500	166.68	154.84	(11.84)	(7.1)	4.4	166.68	154.84	(11.84)	(7.1)	4.4
8	4,000	186.21	172.67	(13.54)	(7.3)	4.3	186.21	172.67	(13.54)	(7.3)	4.3
9	4,500	205.74	190.51	(15.23)	(7.4)	4.2	205.74	190.51	(15.23)	(7.4)	4.2
10	5,000	225.26	208.34	(16.92)	(7.5)	4.2	225.26	208.34	(16.92)	(7.5)	4.2
11	6,000	264.31	244.01	(20.30)	(7.7)	4.1	264.31	244.01	(20.30)	(7.7)	4.1
12	7,000	303.37	279.68	(23.69)	(7.8)	4.0	303.37	279.68	(23.69)	(7.8)	4.0
13	8,000	342.42	315.35	(27.07)	(7.9)	3.9	342.42	315.35	(27.07)	(7.9)	3.9
14	9,000	381.47	351.02	(30.46)	(8.0)	3.9	381.47	351.02	(30.46)	(8.0)	3.9
15	10,000	420.52	386.68	(33.84)	(8.0)	3.9	420.52	386.68	(33.84)	(8.0)	3.9
16	15,000	615.79	565.03	(50.76)	(8.2)	3.8	615.79	565.03	(50.76)	(8.2)	3.8
17	20,000	811.05	743.37	(67.68)	(8.3)	3.7	811.05	743.37	(67.68)	(8.3)	3.7
18	25,000	1,006.31	921.71	(84.60)	(8.4)	3.7	1,006.31	921.71	(84.60)	(8.4)	3.7
19	30,000	1,201.57	1,100.05	(101.52)	(8.4)	3.7	1,201.57	1,100.05	(101.52)	(8.4)	3.7
20	35,000	1,396.83	1,278.39	(118.44)	(8.5)	3.7	1,396.83	1,278.39	(118.44)	(8.5)	3.7
21	40,000	1,592.09	1,456.73	(135.36)	(8.5)	3.6	1,592.09	1,456.73	(135.36)	(8.5)	3.6
22	45,000	1,787.36	1,635.08	(152.28)	(8.5)	3.6	1,787.36	1,635.08	(152.28)	(8.5)	3.6
23	50,000	1,982.62	1,813.42	(169.20)	(8.5)	3.6	1,982.62	1,813.42	(169.20)	(8.5)	3.6
24	55,000	2,177.88	1,991.76	(186.12)	(8.5)	3.6	2,177.88	1,991.76	(186.12)	(8.5)	3.6
25	60,000	2,373.14	2,170.10	(203.04)	(8.6)	3.6	2,373.14	2,170.10	(203.04)	(8.6)	3.6
26	65,000	2,568.40	2,348.44	(219.96)	(8.6)	3.6	2,568.40	2,348.44	(219.96)	(8.6)	3.6
27	70,000	2,763.66	2,526.78	(236.88)	(8.6)	3.6	2,763.66	2,526.78	(236.88)	(8.6)	3.6
28	75,000	2,958.93	2,705.13	(253.80)	(8.6)	3.6	2,958.93	2,705.13	(253.80)	(8.6)	3.6
29	80,000	3,154.19	2,883.47	(270.72)	(8.6)	3.6	3,154.19	2,883.47	(270.72)	(8.6)	3.6

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
Peak kW/mth	-	-	-	-
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Peak kW/mth	1.15	1.15	1.15	1.15
Distribution kWh/mth	0.035114	0.031730	0.035114	0.031730
System Access	30.00	30.00	30.00	30.00

Load Profile	
Load Factor	40%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

Secondary Demand GSD
Education Provision GEI
ROA Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	49.22	47.52	(1.69)	(3.4)	9.5	49.22	47.52	(1.69)	(3.4)	9.5
2	1,000	68.43	65.05	(3.39)	(4.9)	6.5	68.43	65.05	(3.39)	(4.9)	6.5
3	1,500	87.65	82.57	(5.08)	(5.8)	5.5	87.65	82.57	(5.08)	(5.8)	5.5
4	2,000	106.87	100.09	(6.77)	(6.3)	5.0	106.87	100.09	(6.77)	(6.3)	5.0
5	2,500	126.08	117.62	(8.46)	(6.7)	4.7	126.08	117.62	(8.46)	(6.7)	4.7
6	3,000	145.30	135.14	(10.16)	(7.0)	4.5	145.30	135.14	(10.16)	(7.0)	4.5
7	3,500	164.52	152.67	(11.85)	(7.2)	4.4	164.52	152.67	(11.85)	(7.2)	4.4
8	4,000	183.73	170.19	(13.54)	(7.4)	4.3	183.73	170.19	(13.54)	(7.4)	4.3
9	4,500	202.95	187.71	(15.24)	(7.5)	4.2	202.95	187.71	(15.24)	(7.5)	4.2
10	5,000	222.17	205.24	(16.93)	(7.6)	4.1	222.17	205.24	(16.93)	(7.6)	4.1
11	6,000	260.60	240.28	(20.32)	(7.8)	4.0	260.60	240.28	(20.32)	(7.8)	4.0
12	7,000	299.03	275.33	(23.70)	(7.9)	3.9	299.03	275.33	(23.70)	(7.9)	3.9
13	8,000	337.47	310.38	(27.09)	(8.0)	3.9	337.47	310.38	(27.09)	(8.0)	3.9
14	9,000	375.90	345.43	(30.47)	(8.1)	3.8	375.90	345.43	(30.47)	(8.1)	3.8
15	10,000	414.33	380.47	(33.86)	(8.2)	3.8	414.33	380.47	(33.86)	(8.2)	3.8
16	15,000	606.50	555.71	(50.79)	(8.4)	3.7	606.50	555.71	(50.79)	(8.4)	3.7
17	20,000	798.67	730.95	(67.72)	(8.5)	3.7	798.67	730.95	(67.72)	(8.5)	3.7
18	25,000	990.83	906.18	(84.65)	(8.5)	3.6	990.83	906.18	(84.65)	(8.5)	3.6
19	30,000	1,183.00	1,081.42	(101.58)	(8.6)	3.6	1,183.00	1,081.42	(101.58)	(8.6)	3.6
20	35,000	1,375.17	1,256.66	(118.51)	(8.6)	3.6	1,375.17	1,256.66	(118.51)	(8.6)	3.6
21	40,000	1,567.33	1,431.89	(135.44)	(8.6)	3.6	1,567.33	1,431.89	(135.44)	(8.6)	3.6
22	45,000	1,759.50	1,607.13	(152.37)	(8.7)	3.6	1,759.50	1,607.13	(152.37)	(8.7)	3.6
23	50,000	1,951.67	1,782.37	(169.30)	(8.7)	3.6	1,951.67	1,782.37	(169.30)	(8.7)	3.6
24	55,000	2,143.83	1,957.60	(186.23)	(8.7)	3.6	2,143.83	1,957.60	(186.23)	(8.7)	3.6
25	60,000	2,336.00	2,132.84	(203.16)	(8.7)	3.6	2,336.00	2,132.84	(203.16)	(8.7)	3.6
26	65,000	2,528.17	2,308.08	(220.09)	(8.7)	3.6	2,528.17	2,308.08	(220.09)	(8.7)	3.6
27	70,000	2,720.33	2,483.31	(237.02)	(8.7)	3.5	2,720.33	2,483.31	(237.02)	(8.7)	3.5
28	75,000	2,912.50	2,658.55	(253.95)	(8.7)	3.5	2,912.50	2,658.55	(253.95)	(8.7)	3.5
29	80,000	3,104.67	2,833.79	(270.88)	(8.7)	3.5	3,104.67	2,833.79	(270.88)	(8.7)	3.5

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
Peak kW/mth	-	-	-	-
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Peak kW/mth	1.15	1.15	1.15	1.15
Distribution kWh/mth	0.034495	0.031109	0.034495	0.031109
System Access	30.00	30.00	30.00	30.00

Load Profile	
Load Factor	40%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP (Voltage Level 1)
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 42 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	103.93	102.89	(1.04)	(1.0)	20.6	103.93	102.89	(1.04)	(1.0)	20.6
2	1,000	107.86	105.78	(2.08)	(1.9)	10.6	107.86	105.78	(2.08)	(1.9)	10.6
3	1,500	111.79	108.68	(3.12)	(2.8)	7.2	111.79	108.68	(3.12)	(2.8)	7.2
4	2,000	115.72	111.57	(4.15)	(3.6)	5.6	115.72	111.57	(4.15)	(3.6)	5.6
5	2,500	119.65	114.46	(5.19)	(4.3)	4.6	119.65	114.46	(5.19)	(4.3)	4.6
6	3,000	123.58	117.35	(6.23)	(5.0)	3.9	123.58	117.35	(6.23)	(5.0)	3.9
7	4,000	131.44	123.14	(8.31)	(6.3)	3.1	131.44	123.14	(8.31)	(6.3)	3.1
8	5,000	139.31	128.92	(10.39)	(7.5)	2.6	139.31	128.92	(10.39)	(7.5)	2.6
9	6,000	147.17	134.70	(12.46)	(8.5)	2.2	147.17	134.70	(12.46)	(8.5)	2.2
10	7,000	155.03	140.49	(14.54)	(9.4)	2.0	155.03	140.49	(14.54)	(9.4)	2.0
11	8,000	162.89	146.27	(16.62)	(10.2)	1.8	162.89	146.27	(16.62)	(10.2)	1.8
12	9,000	170.75	152.06	(18.69)	(10.9)	1.7	170.75	152.06	(18.69)	(10.9)	1.7
13	10,000	178.61	157.84	(20.77)	(11.6)	1.6	178.61	157.84	(20.77)	(11.6)	1.6
14	15,000	217.92	186.76	(31.16)	(14.3)	1.2	217.92	186.76	(31.16)	(14.3)	1.2
15	20,000	257.22	215.68	(41.54)	(16.1)	1.1	257.22	215.68	(41.54)	(16.1)	1.1
16	25,000	296.53	244.60	(51.93)	(17.5)	1.0	296.53	244.60	(51.93)	(17.5)	1.0
17	30,000	335.83	273.52	(62.31)	(18.6)	0.9	335.83	273.52	(62.31)	(18.6)	0.9
18	35,000	375.14	302.44	(72.70)	(19.4)	0.9	375.14	302.44	(72.70)	(19.4)	0.9
19	40,000	414.44	331.36	(83.08)	(20.0)	0.8	414.44	331.36	(83.08)	(20.0)	0.8
20	45,000	453.75	360.28	(93.47)	(20.6)	0.8	453.75	360.28	(93.47)	(20.6)	0.8
21	50,000	493.05	389.20	(103.85)	(21.1)	0.8	493.05	389.20	(103.85)	(21.1)	0.8
22	60,000	571.66	447.04	(124.62)	(21.8)	0.7	571.66	447.04	(124.62)	(21.8)	0.7
23	70,000	650.27	504.88	(145.39)	(22.4)	0.7	650.27	504.88	(145.39)	(22.4)	0.7
24	80,000	728.88	562.72	(166.16)	(22.8)	0.7	728.88	562.72	(166.16)	(22.8)	0.7
25	90,000	807.49	620.56	(186.93)	(23.1)	0.7	807.49	620.56	(186.93)	(23.1)	0.7
26	100,000	886.10	678.40	(207.70)	(23.4)	0.7	886.10	678.40	(207.70)	(23.4)	0.7
27	110,000	964.71	736.24	(228.47)	(23.7)	0.7	964.71	736.24	(228.47)	(23.7)	0.7
28	120,000	1,043.32	794.08	(249.24)	(23.9)	0.7	1,043.32	794.08	(249.24)	(23.9)	0.7
29	130,000	1,121.93	851.92	(270.01)	(24.1)	0.7	1,121.93	851.92	(270.01)	(24.1)	0.7

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.007861	0.005784	0.007861	0.005784
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

Primary Energy-only GP (Voltage Level 1)
Education Provision GEI
ROA Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	103.67	102.64	(1.03)	(1.0)	20.5	103.67	102.64	(1.03)	(1.0)	20.5
2	1,000	107.33	105.27	(2.06)	(1.9)	10.5	107.33	105.27	(2.06)	(1.9)	10.5
3	1,500	111.00	107.91	(3.09)	(2.8)	7.2	111.00	107.91	(3.09)	(2.8)	7.2
4	2,000	114.66	110.54	(4.12)	(3.6)	5.5	114.66	110.54	(4.12)	(3.6)	5.5
5	2,500	118.33	113.18	(5.15)	(4.4)	4.5	118.33	113.18	(5.15)	(4.4)	4.5
6	3,000	121.99	115.81	(6.18)	(5.1)	3.9	121.99	115.81	(6.18)	(5.1)	3.9
7	4,000	129.32	121.08	(8.24)	(6.4)	3.0	129.32	121.08	(8.24)	(6.4)	3.0
8	5,000	136.66	126.35	(10.31)	(7.5)	2.5	136.66	126.35	(10.31)	(7.5)	2.5
9	6,000	143.99	131.62	(12.37)	(8.6)	2.2	143.99	131.62	(12.37)	(8.6)	2.2
10	7,000	151.32	136.89	(14.43)	(9.5)	2.0	151.32	136.89	(14.43)	(9.5)	2.0
11	8,000	158.65	142.16	(16.49)	(10.4)	1.8	158.65	142.16	(16.49)	(10.4)	1.8
12	9,000	165.98	147.43	(18.55)	(11.2)	1.6	165.98	147.43	(18.55)	(11.2)	1.6
13	10,000	173.31	152.70	(20.61)	(11.9)	1.5	173.31	152.70	(20.61)	(11.9)	1.5
14	15,000	209.97	179.05	(30.92)	(14.7)	1.2	209.97	179.05	(30.92)	(14.7)	1.2
15	20,000	246.62	205.40	(41.22)	(16.7)	1.0	246.62	205.40	(41.22)	(16.7)	1.0
16	25,000	283.28	231.75	(51.53)	(18.2)	0.9	283.28	231.75	(51.53)	(18.2)	0.9
17	30,000	319.93	258.10	(61.83)	(19.3)	0.9	319.93	258.10	(61.83)	(19.3)	0.9
18	35,000	356.59	284.45	(72.13)	(20.2)	0.8	356.59	284.45	(72.13)	(20.2)	0.8
19	40,000	393.24	310.80	(82.44)	(21.0)	0.8	393.24	310.80	(82.44)	(21.0)	0.8
20	45,000	429.90	337.15	(92.75)	(21.6)	0.7	429.90	337.15	(92.75)	(21.6)	0.7
21	50,000	466.55	363.50	(103.05)	(22.1)	0.7	466.55	363.50	(103.05)	(22.1)	0.7
22	60,000	539.86	416.20	(123.66)	(22.9)	0.7	539.86	416.20	(123.66)	(22.9)	0.7
23	70,000	613.17	468.90	(144.27)	(23.5)	0.7	613.17	468.90	(144.27)	(23.5)	0.7
24	80,000	686.48	521.60	(164.88)	(24.0)	0.7	686.48	521.60	(164.88)	(24.0)	0.7
25	90,000	759.79	574.30	(185.49)	(24.4)	0.6	759.79	574.30	(185.49)	(24.4)	0.6
26	100,000	833.10	627.00	(206.10)	(24.7)	0.6	833.10	627.00	(206.10)	(24.7)	0.6
27	110,000	906.41	679.70	(226.71)	(25.0)	0.6	906.41	679.70	(226.71)	(25.0)	0.6
28	120,000	979.72	732.40	(247.32)	(25.2)	0.6	979.72	732.40	(247.32)	(25.2)	0.6
29	130,000	1,053.03	785.10	(267.93)	(25.4)	0.6	1,053.03	785.10	(267.93)	(25.4)	0.6

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.007331	0.005270	0.007331	0.005270
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP (Voltage Level 2)
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 44 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	105.37	103.89	(1.48)	(1.4)	20.8	105.37	103.89	(1.48)	(1.4)	20.8
2	1,000	110.75	107.78	(2.96)	(2.7)	10.8	110.75	107.78	(2.96)	(2.7)	10.8
3	1,500	116.12	111.68	(4.44)	(3.8)	7.4	116.12	111.68	(4.44)	(3.8)	7.4
4	2,000	121.49	115.57	(5.92)	(4.9)	5.8	121.49	115.57	(5.92)	(4.9)	5.8
5	2,500	126.86	119.46	(7.40)	(5.8)	4.8	126.86	119.46	(7.40)	(5.8)	4.8
6	3,000	132.24	123.35	(8.88)	(6.7)	4.1	132.24	123.35	(8.88)	(6.7)	4.1
7	4,000	142.98	131.14	(11.84)	(8.3)	3.3	142.98	131.14	(11.84)	(8.3)	3.3
8	5,000	153.73	138.92	(14.81)	(9.6)	2.8	153.73	138.92	(14.81)	(9.6)	2.8
9	6,000	164.47	146.70	(17.77)	(10.8)	2.4	164.47	146.70	(17.77)	(10.8)	2.4
10	7,000	175.22	154.49	(20.73)	(11.8)	2.2	175.22	154.49	(20.73)	(11.8)	2.2
11	8,000	185.96	162.27	(23.69)	(12.7)	2.0	185.96	162.27	(23.69)	(12.7)	2.0
12	9,000	196.71	170.06	(26.65)	(13.5)	1.9	196.71	170.06	(26.65)	(13.5)	1.9
13	10,000	207.45	177.84	(29.61)	(14.3)	1.8	207.45	177.84	(29.61)	(14.3)	1.8
14	15,000	261.18	216.76	(44.42)	(17.0)	1.4	261.18	216.76	(44.42)	(17.0)	1.4
15	20,000	314.90	255.68	(59.22)	(18.8)	1.3	314.90	255.68	(59.22)	(18.8)	1.3
16	25,000	368.63	294.60	(74.03)	(20.1)	1.2	368.63	294.60	(74.03)	(20.1)	1.2
17	30,000	422.35	333.52	(88.83)	(21.0)	1.1	422.35	333.52	(88.83)	(21.0)	1.1
18	35,000	476.08	372.44	(103.64)	(21.8)	1.1	476.08	372.44	(103.64)	(21.8)	1.1
19	40,000	529.80	411.36	(118.44)	(22.4)	1.0	529.80	411.36	(118.44)	(22.4)	1.0
20	45,000	583.53	450.28	(133.25)	(22.8)	1.0	583.53	450.28	(133.25)	(22.8)	1.0
21	50,000	637.25	489.20	(148.05)	(23.2)	1.0	637.25	489.20	(148.05)	(23.2)	1.0
22	60,000	744.70	567.04	(177.66)	(23.9)	0.9	744.70	567.04	(177.66)	(23.9)	0.9
23	70,000	852.15	644.88	(207.27)	(24.3)	0.9	852.15	644.88	(207.27)	(24.3)	0.9
24	80,000	959.60	722.72	(236.88)	(24.7)	0.9	959.60	722.72	(236.88)	(24.7)	0.9
25	90,000	1,067.05	800.56	(266.49)	(25.0)	0.9	1,067.05	800.56	(266.49)	(25.0)	0.9
26	100,000	1,174.50	878.40	(296.10)	(25.2)	0.9	1,174.50	878.40	(296.10)	(25.2)	0.9
27	110,000	1,281.95	956.24	(325.71)	(25.4)	0.9	1,281.95	956.24	(325.71)	(25.4)	0.9
28	120,000	1,389.40	1,034.08	(355.32)	(25.6)	0.9	1,389.40	1,034.08	(355.32)	(25.6)	0.9
29	130,000	1,496.85	1,111.92	(384.93)	(25.7)	0.9	1,496.85	1,111.92	(384.93)	(25.7)	0.9

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.010745	0.007784	0.010745	0.007784
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP (Voltage Level 2)
Education Provision GEI
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 45 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	105.11	103.64	(1.47)	(1.4)	20.7	105.11	103.64	(1.47)	(1.4)	20.7
2	1,000	110.22	107.27	(2.95)	(2.7)	10.7	110.22	107.27	(2.95)	(2.7)	10.7
3	1,500	115.32	110.91	(4.42)	(3.8)	7.4	115.32	110.91	(4.42)	(3.8)	7.4
4	2,000	120.43	114.54	(5.89)	(4.9)	5.7	120.43	114.54	(5.89)	(4.9)	5.7
5	2,500	125.54	118.18	(7.36)	(5.9)	4.7	125.54	118.18	(7.36)	(5.9)	4.7
6	3,000	130.65	121.81	(8.84)	(6.8)	4.1	130.65	121.81	(8.84)	(6.8)	4.1
7	4,000	140.86	129.08	(11.78)	(8.4)	3.2	140.86	129.08	(11.78)	(8.4)	3.2
8	5,000	151.08	136.35	(14.73)	(9.7)	2.7	151.08	136.35	(14.73)	(9.7)	2.7
9	6,000	161.29	143.62	(17.67)	(11.0)	2.4	161.29	143.62	(17.67)	(11.0)	2.4
10	7,000	171.51	150.89	(20.62)	(12.0)	2.2	171.51	150.89	(20.62)	(12.0)	2.2
11	8,000	181.72	158.16	(23.56)	(13.0)	2.0	181.72	158.16	(23.56)	(13.0)	2.0
12	9,000	191.94	165.43	(26.51)	(13.8)	1.8	191.94	165.43	(26.51)	(13.8)	1.8
13	10,000	202.15	172.70	(29.45)	(14.6)	1.7	202.15	172.70	(29.45)	(14.6)	1.7
14	15,000	253.23	209.05	(44.18)	(17.4)	1.4	253.23	209.05	(44.18)	(17.4)	1.4
15	20,000	304.30	245.40	(58.90)	(19.4)	1.2	304.30	245.40	(58.90)	(19.4)	1.2
16	25,000	355.38	281.75	(73.63)	(20.7)	1.1	355.38	281.75	(73.63)	(20.7)	1.1
17	30,000	406.45	318.10	(88.35)	(21.7)	1.1	406.45	318.10	(88.35)	(21.7)	1.1
18	35,000	457.53	354.45	(103.08)	(22.5)	1.0	457.53	354.45	(103.08)	(22.5)	1.0
19	40,000	508.60	390.80	(117.80)	(23.2)	1.0	508.60	390.80	(117.80)	(23.2)	1.0
20	45,000	559.68	427.15	(132.53)	(23.7)	0.9	559.68	427.15	(132.53)	(23.7)	0.9
21	50,000	610.75	463.50	(147.25)	(24.1)	0.9	610.75	463.50	(147.25)	(24.1)	0.9
22	60,000	712.90	536.20	(176.70)	(24.8)	0.9	712.90	536.20	(176.70)	(24.8)	0.9
23	70,000	815.05	608.90	(206.15)	(25.3)	0.9	815.05	608.90	(206.15)	(25.3)	0.9
24	80,000	917.20	681.60	(235.60)	(25.7)	0.9	917.20	681.60	(235.60)	(25.7)	0.9
25	90,000	1,019.35	754.30	(265.05)	(26.0)	0.8	1,019.35	754.30	(265.05)	(26.0)	0.8
26	100,000	1,121.50	827.00	(294.50)	(26.3)	0.8	1,121.50	827.00	(294.50)	(26.3)	0.8
27	110,000	1,223.65	899.70	(323.95)	(26.5)	0.8	1,223.65	899.70	(323.95)	(26.5)	0.8
28	120,000	1,325.80	972.40	(353.40)	(26.7)	0.8	1,325.80	972.40	(353.40)	(26.7)	0.8
29	130,000	1,427.95	1,045.10	(382.85)	(26.8)	0.8	1,427.95	1,045.10	(382.85)	(26.8)	0.8

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.010215	0.007270	0.010215	0.007270
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP (Voltage Level 3)
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 46 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	108.60	106.85	(1.75)	(1.6)	21.4	108.60	106.85	(1.75)	(1.6)	21.4
2	1,000	117.20	113.70	(3.50)	(3.0)	11.4	117.20	113.70	(3.50)	(3.0)	11.4
3	1,500	125.80	120.55	(5.25)	(4.2)	8.0	125.80	120.55	(5.25)	(4.2)	8.0
4	2,000	134.40	127.40	(7.01)	(5.2)	6.4	134.40	127.40	(7.01)	(5.2)	6.4
5	2,500	143.00	134.25	(8.76)	(6.1)	5.4	143.00	134.25	(8.76)	(6.1)	5.4
6	3,000	151.60	141.09	(10.51)	(6.9)	4.7	151.60	141.09	(10.51)	(6.9)	4.7
7	4,000	168.80	154.79	(14.01)	(8.3)	3.9	168.80	154.79	(14.01)	(8.3)	3.9
8	5,000	186.01	168.49	(17.52)	(9.4)	3.4	186.01	168.49	(17.52)	(9.4)	3.4
9	6,000	203.21	182.19	(21.02)	(10.3)	3.0	203.21	182.19	(21.02)	(10.3)	3.0
10	7,000	220.41	195.89	(24.52)	(11.1)	2.8	220.41	195.89	(24.52)	(11.1)	2.8
11	8,000	237.61	209.58	(28.02)	(11.8)	2.6	237.61	209.58	(28.02)	(11.8)	2.6
12	9,000	254.81	223.28	(31.53)	(12.4)	2.5	254.81	223.28	(31.53)	(12.4)	2.5
13	10,000	272.01	236.98	(35.03)	(12.9)	2.4	272.01	236.98	(35.03)	(12.9)	2.4
14	15,000	358.02	305.47	(52.55)	(14.7)	2.0	358.02	305.47	(52.55)	(14.7)	2.0
15	20,000	444.02	373.96	(70.06)	(15.8)	1.9	444.02	373.96	(70.06)	(15.8)	1.9
16	25,000	530.03	442.45	(87.58)	(16.5)	1.8	530.03	442.45	(87.58)	(16.5)	1.8
17	30,000	616.03	510.94	(105.09)	(17.1)	1.7	616.03	510.94	(105.09)	(17.1)	1.7
18	35,000	702.04	579.43	(122.61)	(17.5)	1.7	702.04	579.43	(122.61)	(17.5)	1.7
19	40,000	788.04	647.92	(140.12)	(17.8)	1.6	788.04	647.92	(140.12)	(17.8)	1.6
20	45,000	874.05	716.41	(157.64)	(18.0)	1.6	874.05	716.41	(157.64)	(18.0)	1.6
21	50,000	960.05	784.90	(175.15)	(18.2)	1.6	960.05	784.90	(175.15)	(18.2)	1.6
22	60,000	1,132.06	921.88	(210.18)	(18.6)	1.5	1,132.06	921.88	(210.18)	(18.6)	1.5
23	70,000	1,304.07	1,058.86	(245.21)	(18.8)	1.5	1,304.07	1,058.86	(245.21)	(18.8)	1.5
24	80,000	1,476.08	1,195.84	(280.24)	(19.0)	1.5	1,476.08	1,195.84	(280.24)	(19.0)	1.5
25	90,000	1,648.09	1,332.82	(315.27)	(19.1)	1.5	1,648.09	1,332.82	(315.27)	(19.1)	1.5
26	100,000	1,820.10	1,469.80	(350.30)	(19.2)	1.5	1,820.10	1,469.80	(350.30)	(19.2)	1.5
27	110,000	1,992.11	1,606.78	(385.33)	(19.3)	1.5	1,992.11	1,606.78	(385.33)	(19.3)	1.5
28	120,000	2,164.12	1,743.76	(420.36)	(19.4)	1.5	2,164.12	1,743.76	(420.36)	(19.4)	1.5
29	130,000	2,336.13	1,880.74	(455.39)	(19.5)	1.4	2,336.13	1,880.74	(455.39)	(19.5)	1.4

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.017201	0.013698	0.017201	0.013698
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

Primary Energy-only GP (Voltage Level 3)
Education Provision GEI
ROA Service

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	108.34	106.59	(1.74)	(1.6)	21.3	108.34	106.59	(1.74)	(1.6)	21.3
2	1,000	116.67	113.18	(3.49)	(3.0)	11.3	116.67	113.18	(3.49)	(3.0)	11.3
3	1,500	125.01	119.78	(5.23)	(4.2)	8.0	125.01	119.78	(5.23)	(4.2)	8.0
4	2,000	133.34	126.37	(6.97)	(5.2)	6.3	133.34	126.37	(6.97)	(5.2)	6.3
5	2,500	141.68	132.96	(8.72)	(6.2)	5.3	141.68	132.96	(8.72)	(6.2)	5.3
6	3,000	150.01	139.55	(10.46)	(7.0)	4.7	150.01	139.55	(10.46)	(7.0)	4.7
7	4,000	166.68	152.74	(13.95)	(8.4)	3.8	166.68	152.74	(13.95)	(8.4)	3.8
8	5,000	183.36	165.92	(17.44)	(9.5)	3.3	183.36	165.92	(17.44)	(9.5)	3.3
9	6,000	200.03	179.10	(20.92)	(10.5)	3.0	200.03	179.10	(20.92)	(10.5)	3.0
10	7,000	216.70	192.29	(24.41)	(11.3)	2.7	216.70	192.29	(24.41)	(11.3)	2.7
11	8,000	233.37	205.47	(27.90)	(12.0)	2.6	233.37	205.47	(27.90)	(12.0)	2.6
12	9,000	250.04	218.66	(31.38)	(12.6)	2.4	250.04	218.66	(31.38)	(12.6)	2.4
13	10,000	266.71	231.84	(34.87)	(13.1)	2.3	266.71	231.84	(34.87)	(13.1)	2.3
14	15,000	350.07	297.76	(52.31)	(14.9)	2.0	350.07	297.76	(52.31)	(14.9)	2.0
15	20,000	433.42	363.68	(69.74)	(16.1)	1.8	433.42	363.68	(69.74)	(16.1)	1.8
16	25,000	516.78	429.60	(87.18)	(16.9)	1.7	516.78	429.60	(87.18)	(16.9)	1.7
17	30,000	600.13	495.52	(104.61)	(17.4)	1.7	600.13	495.52	(104.61)	(17.4)	1.7
18	35,000	683.49	561.44	(122.05)	(17.9)	1.6	683.49	561.44	(122.05)	(17.9)	1.6
19	40,000	766.84	627.36	(139.48)	(18.2)	1.6	766.84	627.36	(139.48)	(18.2)	1.6
20	45,000	850.20	693.28	(156.92)	(18.5)	1.5	850.20	693.28	(156.92)	(18.5)	1.5
21	50,000	933.55	759.20	(174.35)	(18.7)	1.5	933.55	759.20	(174.35)	(18.7)	1.5
22	60,000	1,100.26	891.04	(209.22)	(19.0)	1.5	1,100.26	891.04	(209.22)	(19.0)	1.5
23	70,000	1,266.97	1,022.88	(244.09)	(19.3)	1.5	1,266.97	1,022.88	(244.09)	(19.3)	1.5
24	80,000	1,433.68	1,154.72	(278.96)	(19.5)	1.4	1,433.68	1,154.72	(278.96)	(19.5)	1.4
25	90,000	1,600.39	1,286.56	(313.83)	(19.6)	1.4	1,600.39	1,286.56	(313.83)	(19.6)	1.4
26	100,000	1,767.10	1,418.40	(348.70)	(19.7)	1.4	1,767.10	1,418.40	(348.70)	(19.7)	1.4
27	110,000	1,933.81	1,550.24	(383.57)	(19.8)	1.4	1,933.81	1,550.24	(383.57)	(19.8)	1.4
28	120,000	2,100.52	1,682.08	(418.44)	(19.9)	1.4	2,100.52	1,682.08	(418.44)	(19.9)	1.4
29	130,000	2,267.23	1,813.92	(453.31)	(20.0)	1.4	2,267.23	1,813.92	(453.31)	(20.0)	1.4

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
All kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Distribution kWh/mth	0.016671	0.013184	0.016671	0.013184
System Access	100.00	100.00	100.00	100.00

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 1)
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 48 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					**Winter (Oct - May)**				
				Increase					**Increase**		
Line No.	**Monthly Use**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**	**Present Net Monthly Bill**	**Proposed Net Monthly Bill**	**Amount**	**Percent**	**Proposed Unit Cost**
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	0.49	0.47	(0.02)	(4.5)	0.5	0.49	0.47	(0.02)	(4.5)	0.5
2	110	0.52	0.50	(0.02)	(4.6)	0.5	0.52	0.50	(0.02)	(4.6)	0.5
3	120	0.55	0.52	(0.03)	(4.8)	0.4	0.55	0.52	(0.03)	(4.8)	0.4
4	130	0.58	0.55	(0.03)	(4.9)	0.4	0.58	0.55	(0.03)	(4.9)	0.4
5	140	0.61	0.58	(0.03)	(5.1)	0.4	0.61	0.58	(0.03)	(5.1)	0.4
6	150	0.64	0.60	(0.03)	(5.2)	0.4	0.64	0.60	(0.03)	(5.2)	0.4
7	200	0.78	0.74	(0.04)	(5.6)	0.4	0.78	0.74	(0.04)	(5.6)	0.4
8	250	0.93	0.87	(0.05)	(5.9)	0.3	0.93	0.87	(0.05)	(5.9)	0.3
9	300	1.07	1.01	(0.07)	(6.1)	0.3	1.07	1.01	(0.07)	(6.1)	0.3
10	350	1.22	1.14	(0.08)	(6.3)	0.3	1.22	1.14	(0.08)	(6.3)	0.3
11	400	1.36	1.27	(0.09)	(6.4)	0.3	1.36	1.27	(0.09)	(6.4)	0.3
12	450	1.51	1.41	(0.10)	(6.5)	0.3	1.51	1.41	(0.10)	(6.5)	0.3
13	500	1.65	1.54	(0.11)	(6.6)	0.3	1.65	1.54	(0.11)	(6.6)	0.3
14	600	1.94	1.81	(0.13)	(6.8)	0.3	1.94	1.81	(0.13)	(6.8)	0.3
15	700	2.23	2.08	(0.15)	(6.9)	0.3	2.23	2.08	(0.15)	(6.9)	0.3
16	800	2.52	2.35	(0.18)	(6.9)	0.3	2.52	2.35	(0.18)	(6.9)	0.3
17	900	2.81	2.62	(0.20)	(7.0)	0.3	2.81	2.62	(0.20)	(7.0)	0.3
18	1,000	3.10	2.88	(0.22)	(7.1)	0.3	3.10	2.88	(0.22)	(7.1)	0.3
19	1,500	4.56	4.23	(0.33)	(7.2)	0.3	4.56	4.23	(0.33)	(7.2)	0.3
20	2,000	6.01	5.57	(0.44)	(7.3)	0.3	6.01	5.57	(0.44)	(7.3)	0.3
21	2,500	7.46	6.91	(0.55)	(7.3)	0.3	7.46	6.91	(0.55)	(7.3)	0.3
22	3,000	8.91	8.25	(0.66)	(7.4)	0.3	8.91	8.25	(0.66)	(7.4)	0.3
23	3,500	10.36	9.60	(0.77)	(7.4)	0.3	10.36	9.60	(0.77)	(7.4)	0.3
24	4,000	11.82	10.94	(0.88)	(7.4)	0.3	11.82	10.94	(0.88)	(7.4)	0.3
25	4,500	13.27	12.28	(0.99)	(7.4)	0.3	13.27	12.28	(0.99)	(7.4)	0.3
26	5,000	14.72	13.62	(1.10)	(7.4)	0.3	14.72	13.62	(1.10)	(7.4)	0.3
27	5,500	16.17	14.97	(1.21)	(7.5)	0.3	16.17	14.97	(1.21)	(7.5)	0.3
28	6,000	17.62	16.31	(1.32)	(7.5)	0.3	17.62	16.31	(1.32)	(7.5)	0.3
29	6,500	19.08	17.65	(1.42)	(7.5)	0.3	19.08	17.65	(1.42)	(7.5)	0.3

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
On-peak kWh/mth	-	-	-	-
Off-peak kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Maximum kW/mth	1.06	0.98	1.06	0.98
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 1)
Education Provision GEI
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 49 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	0.46	0.44	(0.02)	(5.1)	0.4	0.46	0.44	(0.02)	(5.1)	0.4
2	110	0.49	0.46	(0.03)	(5.4)	0.4	0.49	0.46	(0.03)	(5.4)	0.4
3	120	0.51	0.48	(0.03)	(5.5)	0.4	0.51	0.48	(0.03)	(5.5)	0.4
4	130	0.54	0.51	(0.03)	(5.7)	0.4	0.54	0.51	(0.03)	(5.7)	0.4
5	140	0.57	0.53	(0.03)	(5.9)	0.4	0.57	0.53	(0.03)	(5.9)	0.4
6	150	0.59	0.56	(0.04)	(6.0)	0.4	0.59	0.56	(0.04)	(6.0)	0.4
7	200	0.72	0.67	(0.05)	(6.6)	0.3	0.72	0.67	(0.05)	(6.6)	0.3
8	250	0.85	0.79	(0.06)	(7.0)	0.3	0.85	0.79	(0.06)	(7.0)	0.3
9	300	0.98	0.91	(0.07)	(7.2)	0.3	0.98	0.91	(0.07)	(7.2)	0.3
10	350	1.11	1.03	(0.08)	(7.5)	0.3	1.11	1.03	(0.08)	(7.5)	0.3
11	400	1.24	1.15	(0.09)	(7.6)	0.3	1.24	1.15	(0.09)	(7.6)	0.3
12	450	1.37	1.27	(0.11)	(7.8)	0.3	1.37	1.27	(0.11)	(7.8)	0.3
13	500	1.50	1.39	(0.12)	(7.9)	0.3	1.50	1.39	(0.12)	(7.9)	0.3
14	600	1.76	1.62	(0.14)	(8.1)	0.3	1.76	1.62	(0.14)	(8.1)	0.3
15	700	2.03	1.86	(0.17)	(8.2)	0.3	2.03	1.86	(0.17)	(8.2)	0.3
16	800	2.29	2.10	(0.19)	(8.3)	0.3	2.29	2.10	(0.19)	(8.3)	0.3
17	900	2.55	2.33	(0.21)	(8.4)	0.3	2.55	2.33	(0.21)	(8.4)	0.3
18	1,000	2.81	2.57	(0.24)	(8.4)	0.3	2.81	2.57	(0.24)	(8.4)	0.3
19	1,500	4.11	3.76	(0.36)	(8.7)	0.3	4.11	3.76	(0.36)	(8.7)	0.3
20	2,000	5.42	4.94	(0.47)	(8.8)	0.2	5.42	4.94	(0.47)	(8.8)	0.2
21	2,500	6.72	6.13	(0.59)	(8.8)	0.2	6.72	6.13	(0.59)	(8.8)	0.2
22	3,000	8.02	7.31	(0.71)	(8.9)	0.2	8.02	7.31	(0.71)	(8.9)	0.2
23	3,500	9.33	8.50	(0.83)	(8.9)	0.2	9.33	8.50	(0.83)	(8.9)	0.2
24	4,000	10.63	9.68	(0.95)	(8.9)	0.2	10.63	9.68	(0.95)	(8.9)	0.2
25	4,500	11.94	10.87	(1.07)	(8.9)	0.2	11.94	10.87	(1.07)	(8.9)	0.2
26	5,000	13.24	12.05	(1.19)	(9.0)	0.2	13.24	12.05	(1.19)	(9.0)	0.2
27	5,500	14.54	13.24	(1.30)	(9.0)	0.2	14.54	13.24	(1.30)	(9.0)	0.2
28	6,000	15.85	14.43	(1.42)	(9.0)	0.2	15.85	14.43	(1.42)	(9.0)	0.2
29	6,500	17.15	15.61	(1.54)	(9.0)	0.2	17.15	15.61	(1.54)	(9.0)	0.2

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
On-peak kWh/mth	-	-	-	-
Off-peak kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Maximum kW/mth	1.06	0.98	1.06	0.98
Distribution kWh/mth	(0.000296)	(0.000314)	(0.000296)	(0.000314)
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 2)
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 50 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	0.72	0.73	0.01	1.1	0.7	0.72	0.73	0.01	1.1	0.7
2	110	0.77	0.78	0.01	1.2	0.7	0.77	0.78	0.01	1.2	0.7
3	120	0.82	0.83	0.01	1.2	0.7	0.82	0.83	0.01	1.2	0.7
4	130	0.88	0.89	0.01	1.2	0.7	0.88	0.89	0.01	1.2	0.7
5	140	0.93	0.94	0.01	1.2	0.7	0.93	0.94	0.01	1.2	0.7
6	150	0.98	0.99	0.01	1.3	0.7	0.98	0.99	0.01	1.3	0.7
7	200	1.24	1.26	0.02	1.3	0.6	1.24	1.26	0.02	1.3	0.6
8	250	1.50	1.52	0.02	1.4	0.6	1.50	1.52	0.02	1.4	0.6
9	300	1.76	1.79	0.02	1.4	0.6	1.76	1.79	0.02	1.4	0.6
10	350	2.02	2.05	0.03	1.4	0.6	2.02	2.05	0.03	1.4	0.6
11	400	2.28	2.32	0.03	1.4	0.6	2.28	2.32	0.03	1.4	0.6
12	450	2.54	2.58	0.04	1.5	0.6	2.54	2.58	0.04	1.5	0.6
13	500	2.80	2.84	0.04	1.5	0.6	2.80	2.84	0.04	1.5	0.6
14	600	3.32	3.37	0.05	1.5	0.6	3.32	3.37	0.05	1.5	0.6
15	700	3.84	3.90	0.06	1.5	0.6	3.84	3.90	0.06	1.5	0.6
16	800	4.36	4.43	0.07	1.5	0.6	4.36	4.43	0.07	1.5	0.6
17	900	4.88	4.96	0.07	1.5	0.6	4.88	4.96	0.07	1.5	0.6
18	1,000	5.41	5.49	0.08	1.5	0.5	5.41	5.49	0.08	1.5	0.5
19	1,500	8.01	8.13	0.12	1.5	0.5	8.01	8.13	0.12	1.5	0.5
20	2,000	10.61	10.78	0.16	1.5	0.5	10.61	10.78	0.16	1.5	0.5
21	2,500	13.21	13.42	0.21	1.6	0.5	13.21	13.42	0.21	1.6	0.5
22	3,000	15.82	16.06	0.25	1.6	0.5	15.82	16.06	0.25	1.6	0.5
23	3,500	18.42	18.71	0.29	1.6	0.5	18.42	18.71	0.29	1.6	0.5
24	4,000	21.02	21.35	0.33	1.6	0.5	21.02	21.35	0.33	1.6	0.5
25	4,500	23.62	23.99	0.37	1.6	0.5	23.62	23.99	0.37	1.6	0.5
26	5,000	26.23	26.64	0.41	1.6	0.5	26.23	26.64	0.41	1.6	0.5
27	5,500	28.83	29.28	0.45	1.6	0.5	28.83	29.28	0.45	1.6	0.5
28	6,000	31.43	31.93	0.49	1.6	0.5	31.43	31.93	0.49	1.6	0.5
29	6,500	34.04	34.57	0.53	1.6	0.5	34.04	34.57	0.53	1.6	0.5

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
On-peak kWh/mth	-	-	-	-
Off-peak kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Maximum kW/mth	1.90	1.93	1.90	1.93
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 2)
Education Provision GEI
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 51 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	0.69	0.70	0.01	0.9	0.7	0.69	0.70	0.01	0.9	0.7
2	110	0.74	0.75	0.01	1.0	0.7	0.74	0.75	0.01	1.0	0.7
3	120	0.79	0.80	0.01	1.0	0.7	0.79	0.80	0.01	1.0	0.7
4	130	0.84	0.85	0.01	1.0	0.7	0.84	0.85	0.01	1.0	0.7
5	140	0.89	0.90	0.01	1.0	0.6	0.89	0.90	0.01	1.0	0.6
6	150	0.94	0.95	0.01	1.0	0.6	0.94	0.95	0.01	1.0	0.6
7	200	1.18	1.19	0.01	1.1	0.6	1.18	1.19	0.01	1.1	0.6
8	250	1.43	1.44	0.02	1.1	0.6	1.43	1.44	0.02	1.1	0.6
9	300	1.67	1.69	0.02	1.2	0.6	1.67	1.69	0.02	1.2	0.6
10	350	1.92	1.94	0.02	1.2	0.6	1.92	1.94	0.02	1.2	0.6
11	400	2.16	2.19	0.03	1.2	0.5	2.16	2.19	0.03	1.2	0.5
12	450	2.41	2.44	0.03	1.2	0.5	2.41	2.44	0.03	1.2	0.5
13	500	2.65	2.69	0.03	1.2	0.5	2.65	2.69	0.03	1.2	0.5
14	600	3.15	3.18	0.04	1.2	0.5	3.15	3.18	0.04	1.2	0.5
15	700	3.64	3.68	0.04	1.2	0.5	3.64	3.68	0.04	1.2	0.5
16	800	4.13	4.18	0.05	1.2	0.5	4.13	4.18	0.05	1.2	0.5
17	900	4.62	4.68	0.06	1.3	0.5	4.62	4.68	0.06	1.3	0.5
18	1,000	5.11	5.17	0.06	1.3	0.5	5.11	5.17	0.06	1.3	0.5
19	1,500	7.56	7.66	0.10	1.3	0.5	7.56	7.66	0.10	1.3	0.5
20	2,000	10.02	10.15	0.13	1.3	0.5	10.02	10.15	0.13	1.3	0.5
21	2,500	12.47	12.63	0.16	1.3	0.5	12.47	12.63	0.16	1.3	0.5
22	3,000	14.93	15.12	0.19	1.3	0.5	14.93	15.12	0.19	1.3	0.5
23	3,500	17.38	17.61	0.22	1.3	0.5	17.38	17.61	0.22	1.3	0.5
24	4,000	19.84	20.09	0.26	1.3	0.5	19.84	20.09	0.26	1.3	0.5
25	4,500	22.29	22.58	0.29	1.3	0.5	22.29	22.58	0.29	1.3	0.5
26	5,000	24.75	25.07	0.32	1.3	0.5	24.75	25.07	0.32	1.3	0.5
27	5,500	27.20	27.56	0.35	1.3	0.5	27.20	27.56	0.35	1.3	0.5
28	6,000	29.66	30.04	0.39	1.3	0.5	29.66	30.04	0.39	1.3	0.5
29	6,500	32.11	32.53	0.42	1.3	0.5	32.11	32.53	0.42	1.3	0.5

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
On-peak kWh/mth	-	-	-	-
Off-peak kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Maximum kW/mth	1.90	1.93	1.90	1.93
Distribution kWh/mth	(0.000296)	(0.000314)	(0.000296)	(0.000314)
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 3)
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4

Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	1.35	1.24	(0.11)	(8.3)	1.2	1.35	1.24	(0.11)	(8.3)	1.2
2	110	1.47	1.35	(0.12)	(8.4)	1.2	1.47	1.35	(0.12)	(8.4)	1.2
3	120	1.58	1.45	(0.13)	(8.5)	1.2	1.58	1.45	(0.13)	(8.5)	1.2
4	130	1.70	1.55	(0.15)	(8.6)	1.2	1.70	1.55	(0.15)	(8.6)	1.2
5	140	1.81	1.66	(0.16)	(8.7)	1.2	1.81	1.66	(0.16)	(8.7)	1.2
6	150	1.93	1.76	(0.17)	(8.7)	1.2	1.93	1.76	(0.17)	(8.7)	1.2
7	200	2.51	2.28	(0.22)	(9.0)	1.1	2.51	2.28	(0.22)	(9.0)	1.1
8	250	3.08	2.80	(0.28)	(9.1)	1.1	3.08	2.80	(0.28)	(9.1)	1.1
9	300	3.66	3.32	(0.34)	(9.2)	1.1	3.66	3.32	(0.34)	(9.2)	1.1
10	350	4.24	3.84	(0.39)	(9.3)	1.1	4.24	3.84	(0.39)	(9.3)	1.1
11	400	4.81	4.36	(0.45)	(9.3)	1.1	4.81	4.36	(0.45)	(9.3)	1.1
12	450	5.39	4.88	(0.51)	(9.4)	1.1	5.39	4.88	(0.51)	(9.4)	1.1
13	500	5.97	5.41	(0.56)	(9.4)	1.1	5.97	5.41	(0.56)	(9.4)	1.1
14	600	7.12	6.45	(0.67)	(9.5)	1.1	7.12	6.45	(0.67)	(9.5)	1.1
15	700	8.27	7.49	(0.79)	(9.5)	1.1	8.27	7.49	(0.79)	(9.5)	1.1
16	800	9.43	8.53	(0.90)	(9.5)	1.1	9.43	8.53	(0.90)	(9.5)	1.1
17	900	10.58	9.57	(1.01)	(9.6)	1.1	10.58	9.57	(1.01)	(9.6)	1.1
18	1,000	11.73	10.61	(1.12)	(9.6)	1.1	11.73	10.61	(1.12)	(9.6)	1.1
19	1,500	17.50	15.82	(1.68)	(9.6)	1.1	17.50	15.82	(1.68)	(9.6)	1.1
20	2,000	23.27	21.02	(2.25)	(9.7)	1.1	23.27	21.02	(2.25)	(9.7)	1.1
21	2,500	29.04	26.23	(2.81)	(9.7)	1.0	29.04	26.23	(2.81)	(9.7)	1.0
22	3,000	34.80	31.43	(3.37)	(9.7)	1.0	34.80	31.43	(3.37)	(9.7)	1.0
23	3,500	40.57	36.64	(3.93)	(9.7)	1.0	40.57	36.64	(3.93)	(9.7)	1.0
24	4,000	46.34	41.84	(4.49)	(9.7)	1.0	46.34	41.84	(4.49)	(9.7)	1.0
25	4,500	52.10	47.05	(5.05)	(9.7)	1.0	52.10	47.05	(5.05)	(9.7)	1.0
26	5,000	57.87	52.25	(5.62)	(9.7)	1.0	57.87	52.25	(5.62)	(9.7)	1.0
27	5,500	63.64	57.46	(6.18)	(9.7)	1.0	63.64	57.46	(6.18)	(9.7)	1.0
28	6,000	69.41	62.67	(6.74)	(9.7)	1.0	69.41	62.67	(6.74)	(9.7)	1.0
29	6,500	75.17	67.87	(7.30)	(9.7)	1.0	75.17	67.87	(7.30)	(9.7)	1.0

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
On-peak kWh/mth	-	-	-	-
Off-peak kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Maximum kW/mth	4.21	3.80	4.21	3.80
Distribution kWh/mth	-	-	-	-
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD (Voltage Level 3)
Education Provision GEI
ROA Service

Case No.: U-20134
Exhibit No.: A-16 (LMC-4)
Schedule: F-4
Page: 53 of 53
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (Jun - Sep)					Winter (Oct - May)				
				Increase					Increase		
Line No.	Monthly Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost	Present Net Monthly Bill	Proposed Net Monthly Bill	Amount	Percent	Proposed Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	1.32	1.21	(0.11)	(8.6)	1.2	1.32	1.21	(0.11)	(8.6)	1.2
2	110	1.44	1.31	(0.13)	(8.7)	1.2	1.44	1.31	(0.13)	(8.7)	1.2
3	120	1.55	1.41	(0.14)	(8.8)	1.2	1.55	1.41	(0.14)	(8.8)	1.2
4	130	1.66	1.51	(0.15)	(8.9)	1.2	1.66	1.51	(0.15)	(8.9)	1.2
5	140	1.77	1.61	(0.16)	(9.0)	1.2	1.77	1.61	(0.16)	(9.0)	1.2
6	150	1.89	1.71	(0.17)	(9.1)	1.1	1.89	1.71	(0.17)	(9.1)	1.1
7	200	2.45	2.22	(0.23)	(9.3)	1.1	2.45	2.22	(0.23)	(9.3)	1.1
8	250	3.01	2.72	(0.29)	(9.5)	1.1	3.01	2.72	(0.29)	(9.5)	1.1
9	300	3.57	3.23	(0.34)	(9.6)	1.1	3.57	3.23	(0.34)	(9.6)	1.1
10	350	4.13	3.73	(0.40)	(9.7)	1.1	4.13	3.73	(0.40)	(9.7)	1.1
11	400	4.70	4.24	(0.46)	(9.7)	1.1	4.70	4.24	(0.46)	(9.7)	1.1
12	450	5.26	4.74	(0.51)	(9.8)	1.1	5.26	4.74	(0.51)	(9.8)	1.1
13	500	5.82	5.25	(0.57)	(9.8)	1.0	5.82	5.25	(0.57)	(9.8)	1.0
14	600	6.94	6.26	(0.68)	(9.9)	1.0	6.94	6.26	(0.68)	(9.9)	1.0
15	700	8.07	7.27	(0.80)	(9.9)	1.0	8.07	7.27	(0.80)	(9.9)	1.0
16	800	9.19	8.28	(0.91)	(9.9)	1.0	9.19	8.28	(0.91)	(9.9)	1.0
17	900	10.31	9.29	(1.03)	(10.0)	1.0	10.31	9.29	(1.03)	(10.0)	1.0
18	1,000	11.44	10.30	(1.14)	(10.0)	1.0	11.44	10.30	(1.14)	(10.0)	1.0
19	1,500	17.06	15.35	(1.71)	(10.0)	1.0	17.06	15.35	(1.71)	(10.0)	1.0
20	2,000	22.68	20.39	(2.28)	(10.1)	1.0	22.68	20.39	(2.28)	(10.1)	1.0
21	2,500	28.30	25.44	(2.85)	(10.1)	1.0	28.30	25.44	(2.85)	(10.1)	1.0
22	3,000	33.91	30.49	(3.42)	(10.1)	1.0	33.91	30.49	(3.42)	(10.1)	1.0
23	3,500	39.53	35.54	(3.99)	(10.1)	1.0	39.53	35.54	(3.99)	(10.1)	1.0
24	4,000	45.15	40.59	(4.57)	(10.1)	1.0	45.15	40.59	(4.57)	(10.1)	1.0
25	4,500	50.77	45.64	(5.14)	(10.1)	1.0	50.77	45.64	(5.14)	(10.1)	1.0
26	5,000	56.39	50.68	(5.71)	(10.1)	1.0	56.39	50.68	(5.71)	(10.1)	1.0
27	5,500	62.01	55.73	(6.28)	(10.1)	1.0	62.01	55.73	(6.28)	(10.1)	1.0
28	6,000	67.63	60.78	(6.85)	(10.1)	1.0	67.63	60.78	(6.85)	(10.1)	1.0
29	6,500	73.25	65.83	(7.42)	(10.1)	1.0	73.25	65.83	(7.42)	(10.1)	1.0

	Summer		Winter	
	Present	Proposed	Present	Proposed
Power Supply Charges				
On-peak kW/mth	-	-	-	-
On-peak kWh/mth	-	-	-	-
Off-peak kWh/mth	-	-	-	-
PSCR Factor kWh/mth	-	-	-	-
Delivery Charges				
Maximum kW/mth	4.21	3.80	4.21	3.80
Distribution kWh/mth	(0.000296)	(0.000314)	(0.000296)	(0.000314)
System Access	200.00	200.00	200.00	200.00

Load Profile	
Load Factor	50%
Onpk kWh	25%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Proposed Investment Recovery Mechanism Surcharges for 2020 and 2021

Case No.: U-20134
Exhibit No. A-68 (LMC-5)

Witness: LMCollins
Date: May 2018

Illustration of the 2020 Investment Recovery Mechanism Distribution Revenue by Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				Proposed Distribution CapEx			**Surcharges**	
Line No.	**Description**	**TY 2019 Sales**	**Max Demand**	**Revenue Requirement** [1]	**Voltage Allocation** [2]	**Total Distribution**	**Energy**	**Demand**
		MWh	MW	$(000)	$(000)	$(000)	($/kWh) (f) / (b)	($/kW) (f) / (c)
	Full Service & ROA							
1	Residential	12,226,200	-	29,146		29,146	0.002384	
2	Rate GS	3,832,795	-	8,501		8,501	0.002218	
3	Rate GSD	3,782,251	10,525	5,512		5,512		0.52
4	Total Secondary	7,615,046	10,525	14,013		14,013		
5	Rate GP Vlt 1	4,229	-	-	1	1	0.000281	
6	Rate GP Vlt 2	90,515	-	-	30	30	0.000330	
7	Rate GP Vlt 3	1,376,847	-	-	807	807	0.000586	
8	Total GP	1,471,591	-	838	838	838		
9	Rate GPD/EIP/GPTU Vlt 1	4,897,316	10,549	-	305	305		0.03
10	Rate GPD/EIP/GPTU Vlt 2	3,876,757	8,750	-	582	582		0.07
11	Rate GPD/EIP/GPTU Vlt 3	6,786,171	16,991	-	2,734	2,734		0.16
12	Total GPD/EIP/GPTU [3]	15,560,244	36,290	3,621	3,621	3,621		
13	Total Primary	17,031,835	36,290	4,459		4,459		
14	Total Lighting & Unmetered	226,556	-	1,232		1,232	0.005438	
15	Total Jurisdictional	37,099,636	46,815	48,850		48,850		

Notes
(1) Exhibit A-32 (JCA-5)
(2) WP-LMC-31
(3) Includes GSG-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Proposed Investment Recovery Mechanism Surcharges for 2020 and 2021

Case No.: U-20134
Exhibit No. A-68 (LMC-5)

Witness: LMCollins
Date: May 2018

Illustration of the 2021 Investment Recovery Mechanism Distribution Revenue by Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				Proposed Distribution CapEx			**Surcharges**	
Line No.	**Description**	**TY 2019 Sales**	**Max Demand**	**Revenue Requirement** (1)	**Voltage Allocation** (2)	**Total Distribution**	**Energy**	**Demand**
		MWh	MW	$(000)	$(000)	$(000)	($/kWh)	($/kW)
							(f) / (b)	(f) / (c)
	Full Service & ROA							
1	Residential	12,226,200	-	58,043		58,043	0.004747	
2	Rate GS	3,832,795	-	16,928		16,928	0.004417	
3	Rate GSD	3,782,251	10,525	10,977		10,977		1.04
4	Total Secondary	7,615,046	10,525	27,905		27,905		
5	Rate GP Vlt 1	4,229	-	-	2	2	0.000559	
6	Rate GP Vlt 2	90,515	-	-	59	59	0.000657	
7	Rate GP Vlt 3	1,376,847	-	-	1,607	1,607	0.001167	
8	Total GP	1,471,591	-	1,669	1,669	1,669		
9	Rate GPD/EIP/GPTU Vlt 1	4,897,316	10,549	-	608	608		0.06
10	Rate GPD/EIP/GPTU Vlt 2	3,876,757	8,750	-	1,160	1,160		0.13
11	Rate GPD/EIP/GPTU Vlt 3	6,786,171	16,991	-	5,444	5,444		0.32
12	Total GPD/EIP/GPTU (3)	15,560,244	36,290	7,212	7,212	7,212		
13	Total Primary	17,031,835	36,290	8,881		8,881		
14	Total Lighting & Unmetered	226,556	-	2,453		2,453	0.010827	
15	Total Jurisdictional	37,099,636	46,815	97,282		97,282		

Notes
(1) Exhibit A-32 (JCA-5)
(2) WP-LMC-31
(3) Includes GSG-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of CSXT Litigation Surcharge

Case No.: U-20134
Exhibit No. A-69 (LMC-6)
Page: 1 of 1
Witness: LMCollins
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				Primary		Secondary		
Line No.	Description	Total	Residential	GP	GPD/ GPTU/ EIP	GS	GSD	Lighting & Unmetered
1	CSXT Litigation Expense [1]	$ 7,599,647						
2	Jurisdictional Energy Allocation Factor [2]		37.60%	4.11%	34.86%	11.72%	11.01%	0.70%
3	Allocated CSXT Litigation Expense		2,857,660	312,479	2,649,111	890,775	836,658	52,964
4	Mar - Aug 2019 Forecasted Customers [3]		9,617,481	10,553	12,096	1,164,998	122,416	
5	Mar - Aug 2019 Forecasted Sales (kWh) [3]							103,573,928
6	CSXT Litigation Surcharge Mar - Aug 2019		$ 0.30	$ 29.61	$ 219.01	$ 0.76	$ 6.83	$ 0.000511

Notes

[1] Exhibit: A-35 (RTB-3)

[2] Exhibit A-16 (JCA-2), Schedule F-1.1, pages 10, 11, and 12, line 1

[3] Consumers Energy's Budget, Planning & Analysis Department

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

	TYPE	MEASURE	2018 Target
Operational	BTG	Public Safety - Gas Infrastructure *a) Vintage Services Eliminated, and* *b) Records Accuracy*	a) ≥13,000 b) ≥90%
	CONTINUOUS IMPROVEMENT GOALS	Customer Experience Index (CXi) *(Forester Index for Digital, Live Agent, and Interactive Voice Response)*	≥52
		Employee Safety (OSHA Recordable) *a) Incidents, and* *b) Incident Rate, and zero fatalities*	a) ≤59 b) ≤0.71
		Cyber Safety (*Phishing Click Rate (Level 2 Tests)*)	≤20%
		Customer On-Time Delivery - Long Cycle *(Orders Completed within Target Window)*	≥60%
		Customer On-Time Delivery - Short Cycle *a) Volume* *b) Adherence to Target Window*	a) ≥45% b) ≥90%
		Distribution Reliability - SAIDI (*System Average Interruption Duration Index - Customer Outage Minutes)*	≤138
		Generation Customer Value *(Fleet Availability at Least Cost Option and within Target Limits)*	≥75%
		Compression Availability (*Unit Availability Under Gas Control Plan)*	≥80%

	OPERATIONAL PERFORMANCE MEASURES						
NUMBER OF TARGETS ACHIEVED	0-3	4	5	6	7	8	9
AWARD PERCENTAGE	0%	50%	75%	100%	125%	150%	200%

50% of total employee payout based on operational goal achievement

PLUS +

	Measure	Weighting	Target
Financial	**Earnings per Share (EPS)**	**Weighting 70%**	**$2.30**
	Operating Cash Flow (Billions)	**Weighting 30%**	**$1.650**

50% of total employee payout based on financial goal achievement

BTG = Breakthrough Goal

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Target Pay Level Market Analysis
Non-Officer

Case No.: U-20134
Exhibit No.: A-71 (AMC-2)
Page: 1 of 1
Witness: AMConrad
Date: May 2018

Exempt Jobs:
2017 Market study

Job Family	# of Employees	Avg, Annual Salary	Market Data	Avg. Salary vs.Market
ACCOUNTING ANALYST	27	$ 94,218	$ 93,924	0.3%
IT BUSINESS	13	$ 94,706	$ 95,305	-0.6%
IT PROJECT MGR	6	$ 154,962	$ 143,030	7.7%
BUSINESS SUPPORT	192	$ 84,152	$ 79,186	5.9%
CALL CNTR TEAM LDR	7	$ 80,095	$ 84,662	-5.7%
COMMUNICATIONS	13	$ 97,700	$ 95,691	2.1%
ELEC./GAS/FLEET FIELD LEADER	232	$ 115,904	$ 122,015	-5.3%
EMPLOYEE DEVELOPMENT	27	$ 103,326	$ 99,132	4.1%
ENGINEER	318	$ 119,134	$ 122,718	-3.0%
ENGINEER TECH	97	$ 96,008	$ 96,005	0.0%
ENVIRONMENTAL PLANNER	8	$ 104,979	$ 103,326	1.6%
FORESTERY	15	$ 90,100	$ 94,536	-4.9%
GENERAL TECHICAL ANALYST	101	$ 85,159	$ 81,386	4.4%
HUMAN RESOURCES	28	$ 103,061	$ 103,637	-0.6%
SAFETY	10	$ 94,163	$ 88,258	6.3%
LABORATORY TECH	3	$ 88,868	$ 84,450	5.0%
RATE ANALYST	11	$ 90,549	$ 82,723	8.6%
EXCUTIVE ASSISTANT	19	$ 77,881	$ 71,627	8.0%
MAINTENANCE/PRODUCTION SUPV	56	$ 105,763	$ 108,105	-2.2%
SYSTEM CONTROLLER	14	$ 98,100	$ 104,968	-7.0%
PLANNER/SCHEDULER	12	$ 92,989	$ 93,059	-0.1%
CORPORATE ACCOUNT MANAGER	22	$ 124,297	$ 128,355	-3.3%
EPC PROJECT MANAGER	25	$ 134,622	$ 133,875	0.6%
GENERATION ASSET MANAGER	12	$ 93,296	$ 94,003	-0.8%
FINANCIAL ANALYST	16	$ 97,307	$ 101,764	-4.6%
TAX	3	$ 113,136	$ 104,093	8.0%
CLAIMS ADM	12	$ 73,198	$ 75,839	-3.6%
IT TECHNICAL	152	$ 106,597	$ 99,084	7.0%
IT SECURITY	8	$ 130,733	$ 137,055	-4.8%
IT ARCHITECTURE	2	$ 157,440	$ 137,731	12.5%

Total exempt employees as a % of market survey matches	46%	
	Average	1.2%
	Weighted Average	0.2%
% of total base salaries Exempt & Non-Exempt	**55%**	

Non-Exempt:
2017 Market study

Job Family	# of Employees	Avg, Annual Salary	Market Data	Avg. Salary vs.Market
Administrative Support Job Family	322	$51,688	$53,506	-3.5%
Customer Service Revenue Recovery Job Family	82	$46,779	$47,650	-1.9%
Operations Support Job Family	20	$55,722	$60,089	-7.8%
Technical Support Job Family	282	$53,180	$59,873	-12.6%
Distribution Project Delivery Job Family	114	$61,433	$67,366	-9.7%
Electric System Owner Job Family	27	$65,112	$67,366	-3.5%
Technician Job Family	268	$70,082	$72,071	-2.8%
Paralegal Job Family	4	$76,872	$86,904	-13.1%
Dispatcher Job Family	12	$74,868	$79,616	-6.3%

Total non-exempt employees as a % of market survey matches	74%	
	Average	-6.8%
	Weighted Average	-2.9%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Annual Incentive O&M Expenses
For the Year 2017 and Test Year 2019
($000)

Case No.: U-20134
Exhibit No.: A-72 (AMC-3)
Page: 1 of 1
Witness: AMConrad
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**Source**
1	Annual Incentive - Officer (1)	$ 1.570	$ 1.471	$ 1.550	
2	Annual Incentive - Non-Officer (EICP)	3.439	3.378	3.479	
3	**Total Expense**	**$ 5.01** (2)	**$ 4.85**	**$ 5.03**	

Footnotes

(1) Excludes named proxy officers

(2) Amounts represent 2017 EICP assuming payout at 100%

Amount of actual payout based on 2017 incentive program results were:

Officer	$ 1.595
Non-officer	3.653
Total	$ 5.248

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

EXHIBITS

OF

MICHAEL J. DELANEY

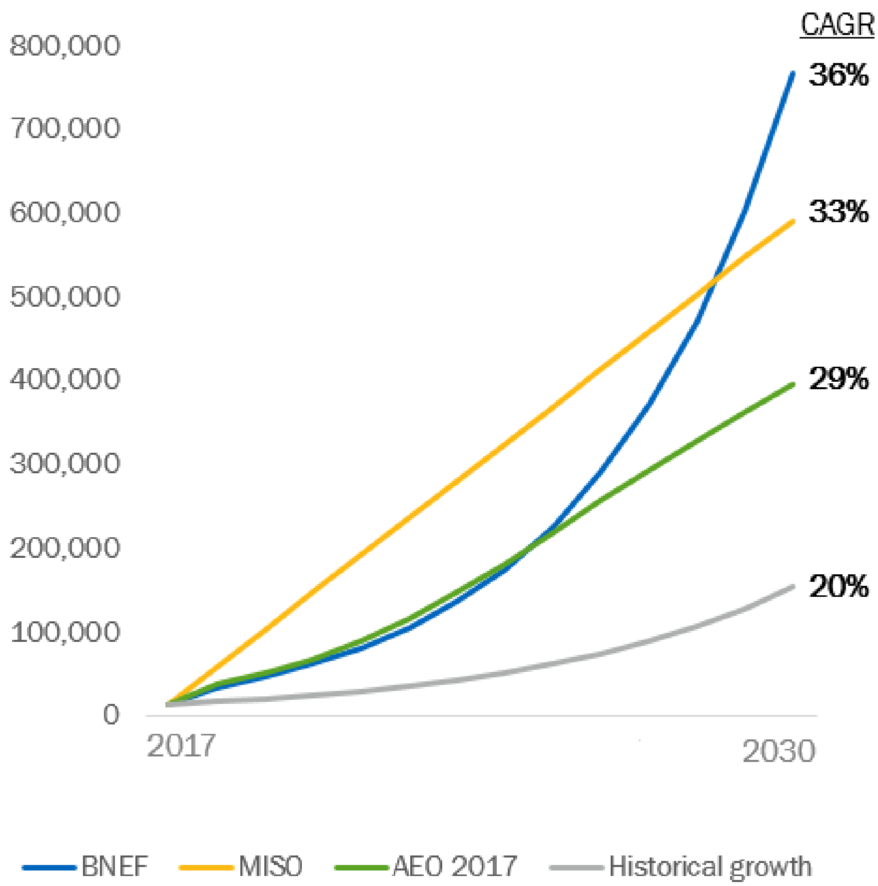
ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Forecasted EV Adoption in Michigan

Below is a chart demonstrating forecasted EV adoption in Michigan through the year 2030 based on data and forecasts from four sources. Electric vehicle growth forecasts vary but all point to rapid growth from a relatively small base today. Forecasts for Michigan were derived using state-level assumptions on national forecasts.



Sources: Bloomberg New Energy Finance (BNEF),[1] MISO data through M.J. Bradley,[2] Annual Energy Outlook (AEO) from Energy Administration Information (EIA),[3] team analysis based on Auto Alliance.[4]

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[1] "Long-Term Electric Vehicle Outlook 2017," Bloomberg New Energy Finance, July 6, 2017. https://www.bnef.com/core/insights/16639/view

[2] Lowell, D., Jones, B., Seamonds, D. (August 2017). "Electric Vehicle Cost-Benefit Analysis: Plug-in Electric Vehicle Cost-Benefit Analysis: Michigan." https://www.nrdc.org/sites/default/files/mi-pev-cb-analysis.pdf

[3] "Annual Energy Outlook 2017," EIA, January 5, 2017. https://www.eia.gov/outlooks/aeo/data/browser/

[4] Alliance of Automobile Manufacturers (2018). "Advanced Technology Vehicle Sales Dashboard." Data compiled by the Alliance of Automobile Manufacturers using information provided by IHS Market Data last updated 2/16/2018. https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

Cost/Benefit Analysis for Consumers Energy Territory

	LOW RANGE: 70% charging off-peak, at home; 2,570 kWH off-peak usage						HIGH RANGE: 85% charging off-peak, at home; 3,121 kWH off-peak usage					
Capacity Calculation												
COS RT Capacity	687,725	$ in thousands					687,725	$ in thousands				
RT Sales	12,226,200	MWh					12,226,200	MWh				
RT Capacity per kWh	0.0563	$ / kWh					0.0563	$ / kWh				
Gross Margin Calculation - *Additional Capacity and Distribution Revenue From Off-Peak Charging*												
Capacity	2,570	kWh	0.0563	$ / kWh	$	145	3,121	kWh	0.0563	$ / kWh	$	176
Distribution	2,570	kWh	0.0446	$ / kWh		115	3,121	kWh	0.0446	$ / kWh		139
Total					$	259					$	315
Lifetime Value Analysis												
Annual gross margin of additional EV on the grid					$	259					$	315
Useful life (years)						10						10
Discount rate (WACC from Case No. U-17990)						5.94%						5.94%
NPV of an additional EV				**LOW**	**$**	**1,913**				**HIGH**	**$**	**2,323**
Assumptions												
All home charging is off-peak												
All public charging is on-peak and does not incur a benefit												
No additional capacity or distribution needed												
Nighttime Savers Rate												
Monthly EV energy use												
Miles driven and charged at home (100% of total miles)						696						845
Avg mi/kWh						3.25						3.25
EV kWh						214						260

Cost/Benefit Analysis For Consumers Energy Territory

Below is a cost/benefit analysis of the lifetime value of an incremental EV to the system. The analysis uses the Company's proposed Nighttime Savers Rate and makes two simplifying assumptions: 1) All charging done at home is off-peak; and 2) all charging done outside of the home is on-peak, with no measurable benefit. The analysis assumes different levels of home charging, from low (70% charging at home) to high (85% charging at home). This range is based on study results that approximately 85% of charging is done at home.[1] Additional assumptions include 11,933 miles driven annually[2] and 3.25 average mi/kWh.[3] Based on these assumptions, adding an EV to the grid provides a 'lifetime value' of $1,900 – $2,300.

1. Idaho National Laboratory. (2015, September). Plugged In: How Americans Charge Their Electric Vehicles. Retrieved from https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
2. U.S. Department of Transportation Federal Highway Administration. Office of Highway Policy Information. https://www.fhwa.dot.gov/policyinformation/
3. Alternative Fuels Data Center. Benefits and Considerations of Electricity as a Vehicle Fuel. Retrieved from https://www.afdc.energy.gov/fuels/electricity_benefits.html

Estimated Program Costs

Below is a chart demonstrating the estimated for each component of the Program.

Component	Description	Year 1 Cost	Program Cost
Residential Infrastructure Program	$500 rebate; 1 per customer; no limit	$0.5 million	$1.5 million
Public and Workplace Charging Infrastructure Program	$5,000 rebate; up to 4 per site-host; limit of 200 rebates	$0.5 million	$1.0 million
DC Fast-Charging Infrastructure Program	Up to $70,000 rebate; up to 2 per site-host; limit of 24 rebates	$1.3 million	$1.7 million
Education and Outreach	Resources to recruit customers and site hosts, reach existing EV drivers, and educate all customers on EVs	$0.5 million	$1.0 million
Technical Development	Development of critical system underpinning EV network; allowance for two FTE	$1.0 million	$2.3 million
Total estimated costs		**$3.8 million**	**$7.5 million**

Rebate Rationale

Chargers

There are a wide range of cost estimates, depending on charger specifications and the location of installation. The two main sources we used to determine rebate amounts for each type of charger were "The Electric Vehicle Charger Selection" report which was collaboratively prepared by multiple California government and non-profit agencies and DOE Idaho National Laboratory's "Plugged In: How Americans Charge Their Electric Vehicles" report. In addition, we reached out to commercial charger providers to corroborate our initial estimates.

Cost Estimates by Charger Type	California Collaborative[1]	DOE Idaho National Laboratory[2]	Rebate Rationale
Residential Level 2 Charger: $500 - $8,000 Installation: $600 - $8,000	Charger: Level 2 charger ranged between $500 - $8,000. Installation: $600 to $13,000 per charger.	Charger: Not included in study Installation: a few hundred dollars to over $8,000. Cost drivers: Higher cost projects due to electrical service upgrades in older homes. Costs varied regionally due to electrician wages and permitting fees.	**Rebate: $500** It is anticipated that the residential rebate will cover approximately 25% of the cost to the customer.
Public Level 2 Charger: $500 - $8,000 Installation: $600 - $8,000		Charger: Not included in study Installation: $600 to $12,660. Cost drivers: Cost primarily affected by the distance from the facility's electrical panel to the charging station location and varied regionally due to labor costs. Lower installation costs were attributed to increased flexibility in choosing locations and the type of equipment to be installed.	**Rebate: $5,000** The $5,000 rebate amount was influenced by (1) equipment required for the program (e.g., 2 ports per charger, demand response capability, and network capability) increased the cost of the Level 2 charging equipment and (2) variability of installation costs for public charging due to the attributes of specific sites. The rebate of up to $5,000 is anticipated to cover approximately 30% of costs to the site host.

[1] California Energy Commission, *et al*. (2018, January) Electric Vehicle Charger Selection Guide. Retrieved from https://www.afdc.energy.gov/uploads/publication/EV_Charger_Selection_Guide_2018-01-112.pdf

[2] Idaho National Laboratory. (2015, September). Plugged In: How Americans Charge Their Electric Vehicles. Retrieved from https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf

Cost Estimates by Charger Type	California Collaborative	DOE Idaho National Laboratory	Rebate Rationale
DCFC Charger: $15,000 - $40,000 Installation: $8,000 – over $50,000	Charger: DCFC chargers ranged between $15,000 to $40,000. Installation: $8,000 to $50,000 per charger.	Charger: Not included in study Installation: Blink DCFC $8,500 to over $50,000. Cost drivers: Study capped installation costs at $50,000. DCFC installations may require electrical service to support the chargers' higher power ratings. Costs varied regionally due to labor costs and permitting requirements.	**Rebate: $70,000** The $70,000 rebate amount was influenced by (1) equipment required for the program (e.g. 2 ports per charger, demand response capability, and network capability) increase the cost of the DCFC charging equipment, (2) variability of installation costs and potential for electrical service upgrades for DCFC due to the attributes of specific sites, and (3) Hawaiian Electric Company[3] noted that capital costs for DCFCs can well exceed $100,000.

Education & Outreach

Description	Cost	Rationale
Customer communication	$0.5 million	Internal marketing and third party vendor estimates based on a targeted marketing campaign that may include paid advertising, bill inserts and physical handouts
Community activities	$0.3 million	Internal marketing estimates based on a variety of community outreach activities that my include ride-and-drive events, demonstration events and event sponsorship
Self-service resources	$0.2 million	Internal marketing estimates based on the continued development of our self-service online tools and resources
3-Year Total	**$1.0 million**	

[3] Hawaiian Electric, Maui Electric, Hawai'i Electric Light. (2018, March). Electrification of Transportation: Strategic Roadmap. Retrieved from https://www.hawaiianelectric.com/Documents/clean_energy_hawaii/electric_vehicles/201803_eot_roadmap.pdf

Technical Development: Information Technology and Administration

Description	Cost	Rationale
Information technology	$1.4 million	Purchase and development of new systems based on internal estimates
Program administration	$0.8 million	Salary and benefits for two full time employees
Program administration expenses	$0.1 million	Travel and other expenses
3-Year Total	**$2.3 million**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

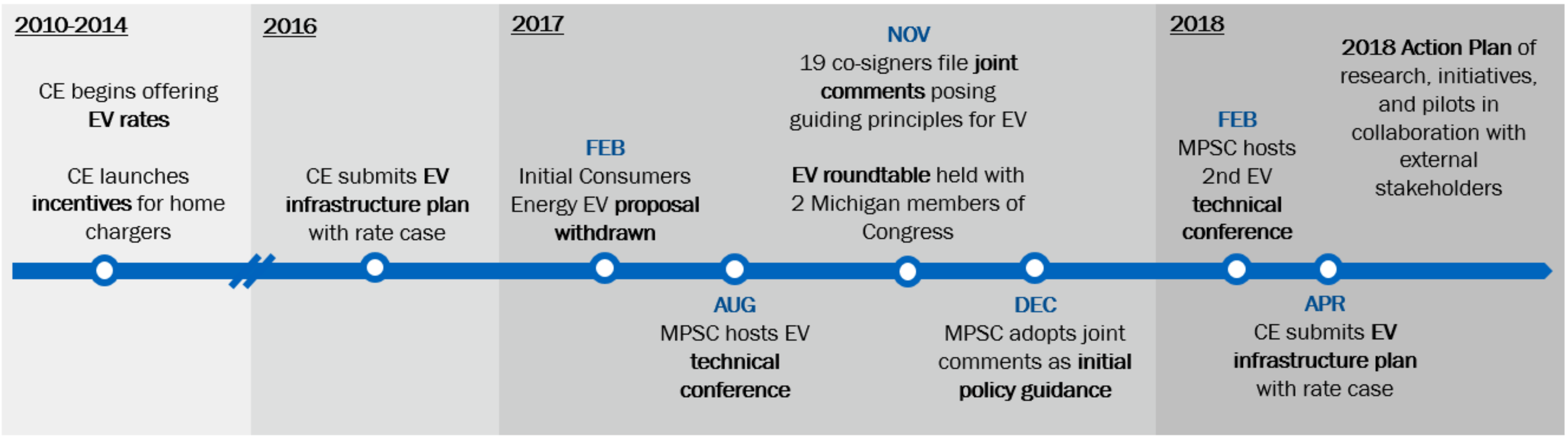
Case No.: U-20134
Exhibit No.: A-77 (MJD-5)
Page: 1 of 1
Witness: MJDelaney
Date: May 2018

Selected, Comparable Utility Programs

Below are selected comparable approved utility programs from the last few years. The table highlights the large range in cost and ownership structures from program to program.

Proposal	Status	Program Details	Cost
Consumers Energy	Proposed	• Residential: estimate 4,000 rebates for up to $500 • Level 2: 200 public, workplace, MDU rebates up to $5,000 • DCFC: 20 rebates for up to $100,000 • Customer-owned	$7.5M
AEP Ohio	Approved	• Level 2: 300 (30% public, 50% workplace, 20% MDU) • DCFC: 75 • Customer-owned	$10M
Duke Energy	Approved	• Level 2: 500 (325 MDU, 100 workplace, 75 long dwell) • DCFC: 30 • Utility-owned	$8M
Eversource Energy	Approved	• Phase I: 1,000 Level 2 and 30 DCFC • Phase II: 3,100 Level 2 and 36 DCFC • Utility owns make-ready infrastructure; customer owns charging station	$55M
Rocky Mountain Power	Approved	• Up to $2 million per year for 5 years • Level 2 single port: 75% of cost up to $4,000 • Level 2 multi-port: 75% of cost up to $7,000 • DCFC single port: 75% of cost up to $45,000 • DCFC multi-port: 75% of cost up to $63,000 • Customer ownership • Additional $200 TOU incentive	$10M
Southern California Edison	Approved	• Level 2: 1,500 (MDU, workplace, public) • Charging station rebates range from 25-100% of cost • Customer-owned	$22M
Southern California Edison	Approved	• Residential: 5,000 rebates • DCFC: 25 rebates • Customer-owned • Also includes Electric Transit Bus Make-Ready Program, Port of Long Beach Rubber Tire Gantry Crane and Port of Long Beach Terminal Yard Tractor (~$7.5 million)	$16M
SDG&E	Approved	• Level 1 and 2: 3,500 (MDU, workplace) • Utility-owned	$45M
Pacific Gas & Electric	Approved	• Level 2: 7,500 ports (MDU, workplace) • Combination of customer- and utility-owned	$130M

History of EVs at Consumers Energy Company



PEV Timeline at Consumers Energy

2010-2014:	Incentive program for home chargers ($2,500/pp); reached 1,300 customers.
2010:	Began offering EV rates and residential/commercial customer support.
2016:	Submitted EV infrastructure plan with rate case (Case No. U-17990) for three-part infrastructure build at $10.6 million estimated cost – (1) Rebate incentive for at-home charging installation, (2) Level 2 public charging/workplace infrastructure installation and (3) fast charge network set up across Michigan.
February 2017:	Withdrew EV infrastructure plan with intention to resubmit as part of broader strategic plan involving customer education and increased stakeholder engagement.
August 2017:	Participated in MPSC Technical Conference on Alternative Fuel Vehicles.
November 2017:	Filing joint comments with 18 other co-signors aligning on guiding principles for EVs.
December 2017:	MPSC adopts joint comments as initial policy guidance.
February 2018:	Participated in MPSC Technical Conference on Alternative Fuel Vehicles.

References Summary

Testimony

1. Alliance of Automobile Manufacturers (2018). Advanced Technology Vehicle Sales Dashboard. Data compiled by the Alliance of Automobile Manufacturers using information provided by IHS Market Data last updated 2/16/2018. Retrieved from https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/
2. IHS vehicle registrations
    a. n/a
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    a. Subscription access only
4. Idaho National Laboratory. (2015, September). Plugged In: How Americans Charge Their Electric Vehicles. Retrieved from https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
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6. National Renewable Energy Laboratory. (2017, September). National Plug-In Electric Vehicle Infrastructure Analysis. Retrieved from https://www.nrel.gov/docs/fy17osti/69031.pdf
7. Alternative Fuels Data Center. Alternative Fueling Station Locator. Retrieved from https://www.afdc.energy.gov/stations/#/find/nearest
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10. KCP&L. (2017, June 7). Kansas City Zooms Ahead in Electric Vehicle Growth. Retrieved from https://cleanchargenetwork.com/the-clean-charge-network/about-clean-charge/
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12. Idaho National Laboratory. (2015, September). Plugged In: How Americans Charge Their Electric Vehicles. Retrieved from https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
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Exhibits

1. Bloomberg New Energy Finance. (2017, July 6). Long-Term Electric Vehicle Outlook 2017. Retrieved from https://www.bnef.com/core/insights/16639/view
2. Lowell, D., Jones, B., Seamonds, D. (2017, August). Electric Vehicle Cost-Benefit Analysis: Plug-in Electric Vehicle Cost-Benefit Analysis: Michigan. Retrieved from https://www.nrdc.org/sites/default/files/mi-pev-cb-analysis.pdf
3. EIA. (2017, January 5). Annual Energy Outlook 2017. Retrieved from https://www.eia.gov/outlooks/aeo/data/browser/
4. Alliance of Automobile Manufacturers (2018). Advanced Technology Vehicle Sales Dashboard. Data compiled by the Alliance of Automobile Manufacturers using information provided by IHS Market Data last updated 2/16/2018. Retrieved from https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/
5. Idaho National Laboratory. (2015, September). Plugged In: How Americans Charge Their Electric Vehicles. Retrieved from https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20134

EXHIBITS

OF

ANDREW J. DENATO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Schedule D-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Overall Rate of Return Summary
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (AJD-1)
Schedule: D-1
Page: 1 of 1
Witness: AJDenato
Date: May 2018

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
		Capital Structure					Weighted Cost			
Line No.	Description	Amount ($000,000) (1)	Percent Permanent Capital (2)	Percent of Total Capital	Cost Rate %		Permanent Capital (7)	Total Cost % (8)	Conversion Factor	Pre-Tax Return (9)
1										
2	Long-Term Debt	$ 6,693	47.24%	37.71%	4.60%	(3)	2.17%	1.74%	1.0000	1.74%
3										
4	Preferred Stock	37	0.26%	0.21%	4.50%	(4)	0.01%	0.01%	1.3390	0.01%
5										
6	Common Shareholder's Equity	7,438	52.50%	41.90%	10.75%	(5)	5.64%	4.50%	1.3390	6.03%
7										
8	Total Permanent Capital	$ 14,168	100.00%							
9										
10	Short-Term Debt	154		0.87%	4.16%	(6)		0.04%	1.0000	0.04%
11										
12	Deferred Income Taxes	3,322		18.71%	0.00%			0.00%	1.0000	0.00%
13										
14	Investment Tax Credit									
15	Long-Term Debt	49		0.28%	4.60%			0.01%	1.0000	0.01%
16	Preferred Stock	0		0.00%	4.50%			0.00%	1.3390	0.00%
17	Common Equity	57		0.32%	10.75%			0.03%	1.3390	0.05%
18										
19	Total	$ 17,750		100.00%				6.33%		7.87%

(1) See Exhibit A-14 (AJD-2), Schedule D-1a, Page 1.
(2) Excludes Short-term Debt, Deferred Income Taxes, and Investment Tax Credit to calculate the rate of return for Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation Section 1.46-6.
(3) See Exhibit A-14 (AJD-4), Schedule D-2.
(4) See Exhibit A-14 (AJD-6), Schedule D-4.
(5) See Exhibit A-14 (SM-1), Schedule D-5.
(6) See Exhibit A-14 (AJD-5), Schedule D-3, Page 1.
(7) Column (c) x column (e).
(8) Column (d) x column (e).
(9) Column (g) x column (h).

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Capital Structure Development
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (AJD-2)
Schedule: D-1a
Page: 1 of 4
Witness: AJDenato
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Historical Capital Structure 13-Month Avg. For Yr. Ended December 31, 2017					Recommended Capital Structure		
Line No.	Description	Amount Outstanding (000,000)	% of Permanent Capital	% of Total Capital	Balances as of Dec. 31, 2017 (000,000)	Test Year Adjustments (000,000)	Amount Outstanding (000,000)	% of Permanent Capital	% of Total Capital
1									
2	Long-Term Debt	$ 5,405	46.08%	35.48%	$ 5,600	$ 1,093	$ 6,693	47.24%	37.71%
3									
4	Preferred Stock	37	0.32%	0.24%	37	-	37	0.26%	0.21%
5									
6	Common Equity	6,287	53.60%	41.28%	6,464	974	7,438	52.50%	41.90%
7									
8	Total Permanent Capital	$ 11,730	100.00%		$ 12,101	$ 2,067	$ 14,168	100.00%	
9									
10	Short-Term Debt, Incl Renewable Liability	182		1.19%	226	(73)	154		0.87%
11									
12	Deferred Income Taxes	3,240		21.27%	3,142	180	3,322		18.71%
13									
14	Investment Tax Credit								
15	Long-Term Debt	37		0.24%	40	9	49		0.28%
16	Preferred Stock	0		0.00%	0	0	0		0.00%
17	Common Equity	43		0.28%	46	11	57		0.32%
18									
19	Total Investment Tax Credit	81		0.53%	87	20	107		0.60%
20									
21	Total Capitalization	$ 15,233		100.00%	$ 15,556		$ 17,750		100.00%

Sources and Support, by Column:

(b) Consumers Energy General Ledger 13-month average balances as of December 31, 2017.
(c) Each line 2, 4, and 6 in column (b) is divided by line 8, column (b).
(d) Each line 2, 4, 6, 10, 12, 15, 16, 17, and 19 in column (b) is divided by line 21, column (b).
(e) Consumers Energy General Ledger balances as of December 31, 2017.
(f) Line 2 Debt maturities and debt issues, line 6 Adjustment for retained earnings and equity contributions, line 10 Adjustment to project short-term debt and renewable liability balance, line 12 Adjustment to project Deferred Income Taxes balance, lines 15-17 Adjustment to project Investment Tax Credit balance.
(g) Column (e) + column (f). Represents 13-month averages.
(h) Each line 2, 4, and 6 in column (g) is divided by line 8, column (g).
(i) Each line 2, 4, 6, 10, 12, 15, 16, 17, and 19 in column (g) is divided by line 21, column (g).

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Long-Term Debt Balance
for the Projected Year Ending December 31, 2019
(in millions)

Case No.: U-20134
Exhibit No.: A-14 (AJD-2)
Schedule: D-1a

Witness: AJDenato
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	**Long-Term Debt**	**Actual Jan-17**	**Actual Feb-17**	**Actual Mar-17**	**Actual Apr-17**	**Actual May-17**	**Actual Jun-17**	**Actual Jul-17**	**Actual Aug-17**	**Actual Sep-17**	**Actual Oct-17**	**Actual Nov-17**	**Actual Dec-17**
1													
2	Beginning Balance	$ 5,333	$ 5,333	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,438	$ 5,338	$ 5,638
3	Add: Issuances	-	350	-	-	-	-	-	-	185	-	300	-
4	Less: Retirements	-	(250)	-	-	-	-	-	-	(180)	(100)	-	-
5	Subtotal	$ 5,333	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,433	$ 5,438	$ 5,338	$ 5,638	$ 5,638
6													
7	Less: Unamortized Fees	(33)	(35)	(38)	(36)	(36)	(37)	(36)	(37)	(37)	(38)	(38)	(38)
8													
9	Ending Balance	$ 5,300	$ 5,398	$ 5,395	$ 5,397	$ 5,397	$ 5,396	$ 5,397	$ 5,396	$ 5,401	$ 5,300	$ 5,600	$ 5,600
10													
11													
12													
13	Long-Term Debt	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
14													
15	Beginning Balance	$ 5,638	$ 5,638	$ 5,638	$ 5,638	$ 5,570	$ 5,970	$ 5,970	$ 5,970	$ 6,670	$ 6,420	$ 6,420	$ 6,420
16	Add: Issuances	-	-	-	-	400	-	-	700	-	-	-	-
17	Less: Retirements	-	-	-	(68)	-	-	-	-	(250)	-	-	-
18	Subtotal	$ 5,638	$ 5,638	$ 5,638	$ 5,570	$ 5,970	$ 5,970	$ 5,970	$ 6,670	$ 6,420	$ 6,420	$ 6,420	$ 6,420
19													
20	Less: Unamortized Fees	(38)	(37)	(37)	(36)	(40)	(39)	(39)	(46)	(45)	(45)	(45)	(44)
21													
22	Ending Balance	$ 5,600	$ 5,601	$ 5,601	$ 5,534	$ 5,930	$ 5,931	$ 5,931	$ 6,624	$ 6,375	$ 6,375	$ 6,375	$ 6,376
23													
24													
25													
26	Long-Term Debt	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
27													
28	Beginning Balance	$ 6,420	$ 6,420	$ 6,720	$ 6,370	$ 6,370	$ 6,370	$ 6,370	$ 6,370	$ 7,645	$ 7,145	$ 7,145	$ 7,145
29	Add: Issuances	-	300	-	-	-	-	-	1,275	-	-	-	-
30	Less: Retirements	-	-	(350)	-	-	-	-	-	(500)	-	-	-
31	Subtotal	$ 6,420	$ 6,720	$ 6,370	$ 6,370	$ 6,370	$ 6,370	$ 6,370	$ 7,645	$ 7,145	$ 7,145	$ 7,145	$ 7,145
32													
33	Less: Unamortized Fees	(44)	(46)	(46)	(45)	(45)	(45)	(44)	(55)	(55)	(54)	(54)	(54)
34													
35	Ending Balance	$ 6,376	$ 6,674	$ 6,324	$ 6,325	$ 6,325	$ 6,325	$ 6,326	$ 7,590	$ 7,090	$ 7,091	$ 7,091	$ 7,091
36													
37	**13-Month Average:**												
38	Subtotal												$ 6,741
39	Less: Unamortized Fees												(49)
40	Ending Balance											**13-Month Average**	**$ 6,693**

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Common Equity Balance
for the Projected Year Ending December 31, 2019
(in millions)

Case No.: U-20134
Exhibit No.: A-14 (AJD-2)
Schedule: D-1a
Page: 3 of 4
Witness: AJDenato
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	**Common Equity**	**Actual Jan-17**	**Actual Feb-17**	**Actual Mar-17**	**Actual Apr-17**	**Actual May-17**	**Actual Jun-17**	**Actual Jul-17**	**Actual Aug-17**	**Actual Sep-17**	**Actual Oct-17**	**Actual Nov-17**	**Actual Dec-17**
1													
2	Beginning Balance	$ 5,906	$ 6,092	$ 6,135	$ 6,218	$ 6,155	$ 6,192	$ 6,434	$ 6,383	$ 6,438	$ 6,504	$ 6,372	$ 6,442
3	Ret. Earnings	(64)	44	83	(63)	37	41	(51)	55	65	(132)	70	22
4	Equity Infusion	250	-	-	-	-	200	-	-	-	-	-	-
5	Ending Balance	$ 6,092	$ 6,135	$ 6,218	$ 6,155	$ 6,192	$ 6,434	$ 6,383	$ 6,438	$ 6,504	$ 6,372	$ 6,442	$ 6,464
6													
7													
8													
9	Common Equity	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
10													
11	Beginning Balance	$ 6,464	$ 6,575	$ 6,585	$ 6,596	$ 6,606	$ 6,617	$ 6,827	$ 6,838	$ 6,848	$ 6,859	$ 6,869	$ 6,880
12	Ret. Earnings	11	11	11	11	11	11	11	11	11	11	11	11
13	Equity Infusion	100	-	-	-	-	200	-	-	-	-	-	-
14	Ending Balance	$ 6,575	$ 6,585	$ 6,596	$ 6,606	$ 6,617	$ 6,827	$ 6,838	$ 6,848	$ 6,859	$ 6,869	$ 6,880	$ 6,890
15													
16													
17													
18	Common Equity	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
19	Beginning Balance	$ 6,890	$ 7,251	$ 7,261	$ 7,272	$ 7,282	$ 7,293	$ 7,603	$ 7,614	$ 7,624	$ 7,635	$ 7,645	$ 7,656
20	Ret. Earnings	11	11	11	11	11	11	11	11	11	11	11	11
21	Equity Infusion	350	-	-	-	-	300	-	-	-	-	-	-
22	Ending Balance	$ 7,251	$ 7,261	$ 7,272	$ 7,282	$ 7,293	$ 7,603	$ 7,614	$ 7,624	$ 7,635	$ 7,645	$ 7,656	$ 7,666
23													
24													
25												**13-Month Average**	$ 7,438
26													
27													
28													
29													
30													
31													
32													

(n)	(o)	(p)	(q)	(r)
	Test Year Impact of Retained Earnings		Test Year Impact of Equity Infusions	
	2018	**2019**	**2018**	**2019**
Jan	$ 11	$ 137	$ 100	$ 650
Feb	$ 21	$ 147	$ 100	$ 650
Mar	$ 32	$ 158	$ 100	$ 650
Apr	$ 42	$ 168	$ 100	$ 650
May	$ 53	$ 179	$ 100	$ 650
Jun	$ 63	$ 189	$ 300	$ 950
Jul	$ 74	$ 200	$ 300	$ 950
Aug	$ 84	$ 210	$ 300	$ 950
Sep	$ 95	$ 221	$ 300	$ 950
Oct	$ 105	$ 231	$ 300	$ 950
Nov	$ 116	$ 242	$ 300	$ 950
Dec	$ 126	$ 252	$ 300	$ 950
13-Month Avg.		$ 189		$ 785

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION	Case No.: U-20134
Consumers Energy Company	Exhibit No.: A-14 (AJD-2)
Capital Structure Development - Projected Deferred Income Tax Balance	Schedule: D-1a
for the Projected Year Ending December 31, 2019	Page: 4 of 4
(in millions)	Witness: AJDenato
	Date: May 2018

Deferred Income Tax Ending Balance

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Actual Jan-17	**Actual Feb-17**	**Actual Mar-17**	**Actual Apr-17**	**Actual May-17**	**Actual Jun-17**	**Actual Jul-17**	**Actual Aug-17**	**Actual Sep-17**	**Actual Oct-17**	**Actual Nov-17**	**Actual Dec-17**
1	$ 3,180	$ 3,186	$ 3,192	$ 3,198	$ 3,203	$ 3,311	$ 3,309	$ 3,307	$ 3,351	$ 3,243	$ 3,236	$ 3,142
2												
3												
4	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
5	$ 3,150	$ 3,158	$ 3,166	$ 3,175	$ 3,183	$ 3,191	$ 3,199	$ 3,207	$ 3,215	$ 3,223	$ 3,232	$ 3,240
6												
7												
8												
9	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
10	$ 3,253	$ 3,267	$ 3,281	$ 3,294	$ 3,308	$ 3,322	$ 3,335	$ 3,349	$ 3,363	$ 3,376	$ 3,390	$ 3,404
11												
12												
13											**13-Month Average**	$ 3,322

Schedule D-1b

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Development of Capital Structure
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (AJD-3)
Schedule: D-1b
Page: 1 of 1
Witness: AJDenato
Date: May 2018

Line No.	(a) Description	(b) Financial Basis	(c) MPSC Ratemaking Basis
I.	LONG-TERM DEBT:		
a.	First Mortgage Bonds	Include	Include
b.	Trust Preferred Securities	Include	Include
c.	Other Subordinated LTD	Include	Include
d.	Unamortized Debt Premium	Include	Include
e.	Unamortized Debt Discount	Include	Include
f.	Unamortized Debt Expense	Include	Include
g.	Current Maturities	**Exclude**	**Include**
h.	Capitalized Leases	**Include**	**Exclude**
II.	SHORT-TERM DEBT	Include	Include
III.	PREFERRED STOCK EXPENSE		
a.	Preferred Stock	Include	Include
b.	Trust Preferred Securities	Exclude	Exclude
c.	Preferred Stock Expense	Include	Include
IV.	COMMON EQUITY		
a.	Common Stock Issued	Include	Include
b.	Premium on Common Stock	Include	Include
c.	Donations Received From Stockholders	Include	Include
d.	Common Stock Expense	Include	Include
e.	Gain on Reacquired Stock	Include	Include
f.	Miscellaneous Paid In Capital	Include	Include
g.	Mark-to-Market Accounting	**Include**	**Exclude**
h.	Appropriated Retained Earnings	Include	Include
I.	Unappropriated Retained Earnings	Include	Include
j.	FAS 90 (Abandoned Plant)	Include	Include
V.	DEFERRED ITC	**Exclude**	**Include**
VI.	DEFERRED TAXES	**Exclude**	**Include**
VII.	DEFERRED JDITC	**Exclude**	**Include**

Schedule D-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Long-Term Debt
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (AJD-4)
Schedule: D-2
Page: 1 of 1
Witness: AJDenato
Date: May 2018

Line No.	(a) Description	(b) Original Issue Date	(c) Stated Maturity Date	(d) Interest Rate (%)	(d1) Interest Payments Per Year	(e) Amount of Offering ($000)	(f) Price to Public (%)	(g) Underwriting Expenses (%)	(g1) Underwriting Expenses ($000)	(g2) Financing Expenses (%)	(g3) Financing Expenses ($000)	(g4) (Premium) Discount ($000)	(h) Net Proceeds to the Company (%)	(i) Cost Based on Net Proceeds (%)	(j) Amount Outstanding ($000)	(k) Annual Cost ($000)
1																
2	**Mortgage Bonds**															
3	5.650%	24-Mar-05	15-Apr-20	5.650%	2	300,000	99.60%	0.750%	2,250.00	0.16%	482.50	1,188.00	98.693%	5.7807%	$ 300,000	$ 17,342
4	5.800%	11-Aug-05	15-Sep-35	5.800%	2	175,000	99.81%	0.875%	1,531.25	0.17%	299.97	337.75	98.761%	5.8879%	175,000	10,304
5	6.125%	15-Sep-08	15-Mar-19	6.125%	2	350,000	99.93%	0.650%	2,275.00	0.08%	290.40	245.00	99.197%	6.2303%	80,769	5,032
6	6.700%	06-Mar-09	15-Sep-19	6.700%	2	500,000	99.95%	0.650%	3,250.00	0.06%	296.40	240.00	99.243%	6.8016%	346,154	23,544
7	5.300%	01-Sep-10	01-Sep-22	5.300%	2	250,000	100.00%	0.362%	906.09	0.03%	72.90	0.00	99.608%	5.3446%	250,000	13,362
8	6.170%	01-Sep-10	01-Sep-40	6.170%	2	50,000	100.00%	0.906%	453.04	0.08%	38.99	0.00	99.016%	6.2430%	50,000	3,121
9	3.770%	15-Oct-10	15-Oct-20	3.770%	2	100,000	100.00%	0.500%	500.00	0.03%	34.02	0.00	99.466%	3.8348%	100,000	3,835
10	4.970%	15-Oct-10	15-Oct-40	4.970%	2	50,000	100.00%	0.500%	250.00	0.04%	19.58	0.00	99.461%	5.0049%	50,000	2,502
11	2.850%	08-May-12	15-May-22	2.850%	2	375,000	99.99%	0.650%	2,437.50	0.14%	543.30	33.75	99.196%	2.9432%	375,000	11,037
12	3.190%	17-Dec-12	16-Dec-24	3.190%	2	51,500	100.00%	0.501%	258.27	0.03%	17.63	0.00	99.464%	3.2443%	51,500	1,671
13	3.390%	17-Dec-12	15-Dec-27	3.390%	2	35,500	100.00%	0.501%	178.03	0.04%	13.76	0.00	99.460%	3.4364%	35,500	1,220
14	4.310%	17-Dec-12	15-Dec-42	4.310%	2	263,000	100.00%	0.501%	1,318.92	0.03%	68.78	0.00	99.472%	4.3416%	263,000	11,418
15	3.950%	17-May-13	15-May-43	3.950%	2	425,000	99.84%	0.875%	3,718.75	0.16%	675.43	667.25	98.809%	4.0187%	425,000	17,079
16	3.375%	09-Aug-13	15-Aug-23	3.375%	2	325,000	99.95%	0.650%	2,112.50	0.11%	373.54	165.75	99.184%	3.4721%	325,000	11,284
17	3.125%	18-Aug-14	31-Aug-24	3.125%	2	250,000	99.90%	0.650%	1,625.00	0.14%	349.86	255.00	99.108%	3.2297%	250,000	8,074
18	4.350%	18-Aug-14	31-Aug-64	4.350%	2	250,000	99.14%	0.875%	2,187.50	0.12%	309.64	2,157.50	98.138%	4.4430%	250,000	11,107
19	4.100%	06-Nov-15	15-Nov-45	4.100%	2	250,000	99.91%	0.875%	2,187.50	0.18%	447.46	217.50	98.859%	4.1669%	250,000	10,417
20	3.250%	10-Aug-16	15-Aug-46	3.250%	2	450,000	99.22%	0.875%	3,937.50	0.18%	821.46	3,501.00	98.164%	3.3474%	450,000	15,063
21	3.950%	22-Feb-17	15-Jul-47	3.950%	2	350,000	99.58%	0.875%	3,062.50	0.19%	669.34	1,463.00	98.516%	4.0350%	350,000	14,122
22	3.18% (Private Placement)	28-Sep-17	28-Sep-32	3.180%	2	40,000	100.00%	0.301%	120.48	0.02%	6.38	0.00	99.683%	3.2068%	40,000	1,283
23	3.52% (Private Placement)	28-Sep-17	28-Sep-37	3.520%	2	125,000	100.00%	0.402%	501.98	0.02%	26.57	0.00	99.577%	3.5497%	125,000	4,437
24	3.86% (Private Placement)	28-Sep-17	28-Sep-52	3.860%	2	20,000	100.00%	0.703%	140.56	0.04%	7.44	0.00	99.260%	3.8989%	20,000	780
25	3.18% (Private Placement)	15-Nov-17	15-Nov-32	3.180%	2	60,000	100.00%	0.301%	180.71	0.02%	9.37	0.00	99.683%	3.2068%	60,000	1,924
26	3.52% (Private Placement)	15-Nov-17	15-Nov-37	3.520%	2	210,000	100.00%	0.402%	843.33	0.02%	43.70	0.00	99.578%	3.5497%	210,000	7,454
27	3.86% (Private Placement)	15-Nov-17	15-Nov-52	3.860%	2	30,000	100.00%	0.703%	210.83	0.04%	10.93	0.00	99.261%	3.8989%	30,000	1,170
28	New Debt Issue #1	01-May-18	01-May-48	4.900%	2	400,000	100.00%	0.875%	3,500.00	0.15%	600.00	0.00	98.975%	4.9661%	400,000	19,864
29	New Debt Issue #2	01-Aug-18	01-Aug-48	4.900%	2	700,000	100.00%	0.875%	6,125.00	0.15%	1,050.00	0.00	98.975%	4.9661%	700,000	34,762
30	New Debt Issue #3	01-Feb-19	01-Feb-49	5.400%	2	300,000	100.00%	0.875%	2,625.00	0.15%	450.00	0.00	98.975%	5.4699%	253,846	13,885
31	New Debt Issue #4	01-Aug-19	01-Aug-49	5.400%	2	1,275,000	100.00%	0.875%	11,156.25	0.15%	1,912.50	0.00	98.975%	5.4699%	490,385	26,824
32	Total Mortgage Bonds														$ 6,706,154	$ 303,920
33																
34	**Other Long-Term Debt**															
35	PCRB - MSF LORB - 05	26-Apr-05	01-Apr-35	2.002%	12	35,000	100.00%	0.000%	0.00	0.13%	45.75	0.00	99.869%	2.0078%	$ 35,000	$ 703
36																
37	Total Long-Term Debt														$ 6,741,154	$ 304,623
38																
39	Amortization of Losses on Reacquired Debt with Refunding (including Call Premiums)															5,609
40																
41	PCRB Fees															46
42																
43	Total Long-Term Debt Before Unamortized Expense and Premium													4.60%	$ 6,741,154	$ 310,278
44																
45	Unamortized Debt Discount, Expense and Premium														(48,538)	
46																
47	Total Long-Term Debt Balance														$ 6,692,615	
48																
49	Annual Cost													4.60%		
50																

Ties to 13-Month Average in Exhibit A-14 (AJD-2), Schedule D-1a, page 2

51 **Calculations:**
52 Column (i) = Yield formula based on inputs from column (b),column (c), column (d), column (d1), and column (h) calculated on an annualized basis.
53 Column (j) = represents the average amount of debt outstanding for the test year.
54 Column (k) = column (i)*column (j).
55 Lines 5, 6, 30, and 31 - As this is a partial year debt outstanding, pro-rata balance and pro-rata interest expense are used which would result in the same cost rate as an annual analysis,
56 but provides a more accurate average debt balance for the Test Year. This would make the Total Debt balance line 47 tie to the debt balance shown on Exhibit A-14 (AJD-2), Schedule D-1a, page 3.
57 Line 35 PCRB Coupon Rate = 70% of Projected LIBOR Rate of 2.86% (Average of Projected Global Insight and Blue Chip LIBOR Rates).
58 Line 39 - Amortization of losses on reacquired debt with refundings projected for the test year ending December 31, 2019.

Line	Projected LIBOR Rate	2019	Projected New Debt Issue Interest Rates	2018 New Debt Issue #1 / #2	2019 New Debt Issue #3 / #4
59					
60					
61			Projected 30-Year Treasury Rate		
62	Global Insight (February 2018)	2.92%	Value Line (March 2, 2018)	3.7%	4.1%
63	Blue Chip (December 2017)	2.80%	Blue Chip (Mar. 2018 for 2018 / Dec. 2017 for 2019)	3.3%	3.8%
64	Average of Global Insight & Blue Chip	2.86%	Average of Value Line & Blue Chip	3.5%	4.0%
65					
66			Add: Historical 30-Year Bond Spread	1.4%	1.4%
67				**4.9%**	**5.4%**

Schedule D-3

MICHIGAN PUBLIC SERVICE COMMISSION	Case No.: U-20134
Consumers Energy Company	Exhibit No.: A-14 (AJD-5)
Cost of Short-Term Debt - Revolver / Commercial Paper	Schedule: D-3
for the Projected Year Ending December 31, 2019	Page: 1 of 2
(in millions)	Witness: AJDenato
	Date: May 2018

Line No.	Description	(a) **Average Borrowings**	(b) **Cost of Borrowings**	(c) **Cost Rate**
1	Short-Term Debt - Revolver / Commercial Paper	$ 113.1	$ 5.2	
2				
3	Short-Term Debt - Renewable Liability	40.7	1.2	
4				
5	Total Short-Term Debt	$ 153.8	$ 6.4	4.16%

Sources:

Column (a): Average borrowings per Exhibit A-14 (AJD-7), Schedule D-6.
Column (b): Short-Term Debt - Revolver cost per Exhibit A-14 (AJD-5), Schedule D-3, page 2.
Short-Term Debt - Renewable Liability cost equal to the average borrowings (column (a)) times the projected interest on borrowings rate of 3.01%, per Exhibit A-14 (AJD-5), Schedule D-3, page 2.
Column (c) = column (b)/column (a).

Schedule D-3

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Cost of Short-Term Debt - Revolver / Commercial Paper
for the Projected Year Ending December 31, 2019
(in millions)

Case No.: U-20134
Exhibit No.: A-14 (AJD-5)
Schedule: D-3

Witness: AJDenato
Date: May 2018

Summary

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				Test Year Assumption			
Facility	**Agreement Date**	**Expiration**	**Facility Amount**	**Less: Avg. Borrowings**	**Less: Letters of Credit**	**Amount Unused** [a]	**Upfront Fee Amort**
				(A)	(B)	(C)	(D)
1. JPMorgan Revolver	May 2015	May 2022	$ 850.0	$ -	$ 6.8	$ 843.2	$ 0.3
2. Commercial Paper Facility	Sep. 2014	N/A	$ 500.0	$ 113.1	$ -	$ -	$ -
3. Scotiabank Revolver	Nov. 2015	Nov. 2019	$ 250.0	$ -	$ -	$ 250.0	$ -
4. JPMorgan Letter of Credit Facility 1	Sep. 2011	Sep. 2019	$ 30.0	$ -	$ 30.0	$ -	$ -
5. JPMorgan Letter of Credit Facility 2	Aug. 2012	Aug. 2019	$ 35.5	$ -	$ 35.5	$ -	$ -

Cost of Short-Term Debt - Revolver / Commercial Paper

(A) **Interest on Borrowings** - Calculated on the projected drawn balance at LIBOR plus the spread on borrowings.

Facility	LIBOR [a]	Plus: Spread	Projected Rate	Avg. Borrowings	Cost
1. JPMorgan Revolver	2.86%	0.875%	3.74%	$ -	$ -
2. Commercial Paper Facility	2.86%	0.150%	3.01%	113.1	3.4
3. Scotiabank Revolver	2.86%	0.750%	3.61%	-	-
4. JPMorgan Letter of Credit Facility 1	N/A - Letter of Credit Facility			-	-
5. JPMorgan Letter of Credit Facility 2	N/A - Letter of Credit Facility			-	-
					$ 3.4

(B) **Letter of Credit Fees** - Calculated on the projected letters of credit outstanding at a rate equal to the spread.

Facility	Letter of Credit Type	Projected Rate	Letters of Credit	Cost
1. JPMorgan Revolver	Regular Operating	0.875%	$ 6.8	$ 0.1
2. Commercial Paper Facility	N/A	N/A	-	-
3. Scotiabank Revolver	N/A	N/A	-	-
4. JPMorgan Letter of Credit Facility 1	Palisades PPA	0.55%	30.0	0.2
5. JPMorgan Letter of Credit Facility 2	Tax Exempt Bonds	1.025%	35.5	0.4
				$ 0.7

(C) **Unused (Commitment) Fees** - Calculated on the unused portion of the revolver at a rate stated in the facility agreement.

Facility	Projected Rate	Amount Unused [b]	Cost
1. JPMorgan Revolver	0.075%	$ 843.2	$ 0.6
2. Commercial Paper Facility	N/A	-	-
3. Scotiabank Revolver	0.075%	$ 250.0	$ 0.2
4. JPMorgan Letter of Credit Facility 1	N/A	-	-
5. JPMorgan Letter of Credit Facility 2	N/A	-	-
			$ 0.8

(D) **Amortization / Expense of Facility Fees** - Fees paid upfront at the inception or amendment to the facility, amortized over the life of the facility.

Facility	Annual Cost
1. JPMorgan Revolver	$ 0.3
2. Commercial Paper Facility	-
3. Scotiabank Revolver	-
4. JPMorgan Letter of Credit Facility 1	-
5. JPMorgan Letter of Credit Facility 2	-
	$ 0.3

Total Cost of Short-Term Debt - Revolver / Commercial Paper	**$ 5.2**

[a] Projected LIBOR rate per Exhibit A-14 (AJD-4), Schedule D-2. Forecasted LIBOR assumed to closely approximate commercial paper rate.

[b] Commercial Paper drawn balances go against, or are "backstopped," by the Company's JPMorgan Revolver.
To the extent amounts are borrowed under the Commercial Paper Facility, the availability of the JPMorgan Revolver are reduced.
These borrowings do not, however, reduce the "unused" portion of the revolver in calculating the unused (commitment) fees.

Schedule D-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Preferred Stock
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (AJD-6)
Schedule: D-4
Page: 1 of 1
Witness: AJDenato
Date: May 2018

Line No.	(a) Description		(b) Annual Dividend	(c) Par Value	(d) Finance Expense	(e) (Premium) Discount	(f) Net Proceeds Received By Company	(g) Number Of Shares Outstanding	(h) Total Value Of Net Proceeds (000)	(i) Cost Rates	(j) Annual Cost (000)
	PREFERRED STOCK:										
1	$4.500	Series	$4.500	$100.00	$0.00	$0.00	$100.00	373,148	$37,315	4.50%	$1,679

Calculations:
Column (i) = (column (h)*column (b)/column (f))/column (h).
Column (j) = column (h)*column (i).

Schedule D-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Short-Term Debt Utilization
for the Projected Year Ending December 31, 2019
(in millions)

Case No.: U-20134
Exhibit No.: A-14 (AJD-7)
Schedule: D-6
Page: 1 of 1
Witness: AJDenato
Date: May 2018

Ending Short-Term Debt - Revolver / Commercial Paper Balance

Line No.	(a) Actual Jan-17	(b) Actual Feb-17	(c) Actual Mar-17	(d) Actual Apr-17	(e) Actual May-17	(f) Actual Jun-17	(g) Actual Jul-17	(h) Actual Aug-17	(i) Actual Sep-17	(j) Actual Oct-17	(k) Actual Nov-17	(l) Actual Dec-17
1												
2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 230	$ 389	$ 256	$ 170
3												
4												
5	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
6												
7	$ 79	$ 59	$ -	$ -	$ -	$ -	$ -	$ -	$ 200	$ 300	$ 275	$ 235
8												
9												
10	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
11												
12	$ 100	$ 80	$ -	$ -	$ -	$ -	$ -	$ -	$ 225	$ 325	$ 250	$ 255
13												
14											**13-Month Average**	$ 113

Ending Short-Term Debt - Renewable Liability Balance [a]

Line No.												
15	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**
16	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
17												
18	$ 81	$ 79	$ 76	$ 76	$ 75	$ 69	$ 70	$ 71	$ 64	$ 61	$ 60	$ 56
19												
20												
21	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
22												
23	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55
24												
25												
26	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
27												
28	$ 52	$ 50	$ 48	$ 45	$ 43	$ 41	$ 38	$ 36	$ 34	$ 31	$ 29	$ 27
29												
30											**13-Month Average**	$ 41
31												
32												

33 [a] 2018 and 2019 projected year-end Renewable Liability balances are consistent with the Company's Renewable Energy Plan reflected in Case No. U-18231.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Current and Historical Credit Ratings
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-80 (AJD-8)
Page: 1 of 1
Witness: AJDenato
Date: May 2018

Line No.		(a)	(b)	(c)	(d)	(e)	(f)
			Credit Ratings				
1			**Standard & Poors Ratings at Year End**				
2		**Current**	**2017**	**2016**	**2015**	**2014**	**2013**
3	**Consumers Energy Company**						
4	Senior Secured Debt	A	A	A	A	A	A-
5	Commercial Paper	A-2	A-2	A-2	A-2	A-2	N/A
6	Senior Unsecured Debt	N/A	N/A	N/A	N/A	N/A	N/A
7	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
8	Preferred Stock	N/A	N/A	N/A	BB+	BB+	BB+
9	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
10							
11	**CMS Energy Corporation**						
12	Senior Secured Debt	N/A	N/A	N/A	N/A	N/A	N/A
13	Senior Unsecured Debt	BBB	BBB	BBB	BBB	BBB	BBB-
14	Junior Subordinated Debt	BBB-	N/A	N/A	N/A	N/A	N/A
15	Hybrid Preferred Securities	N/A	N/A	N/A	BB+	BB+	BB+
16	Preferred Stock	N/A	N/A	N/A	N/A	N/A	N/A
17	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
18							
19							
20			**Moody's Ratings at Year End**				
21		**Current**	**2017**	**2016**	**2015**	**2014**	**2013**
22	**Consumers Energy Company**						
23	Senior Secured Debt	Aa3	Aa3	A1	A1	A1	A2
24	Commercial Paper	P-1	P-1	P-2	P-2	P-2	N/A
25	Senior Unsecured Debt	N/A	N/A	N/A	A3	A3	Baa1
26	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
27	Preferred Stock	A3	A3	Baa1	Baa1	Baa1	Baa2
28	Outlook	Stable	Stable	Positive	Stable	Stable	Stable
29							
30	**CMS Energy Corporation**						
31	Senior Secured Debt	A3	A3	Baa1	Baa1	Baa1	Baa2
32	Senior Unsecured Debt	Baa1	Baa1	Baa2	Baa2	Baa2	Baa3
33	Junior Subordinated Debt	Baa2	N/A	N/A	N/A	N/A	N/A
34	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
35	Preferred Stock	N/A	N/A	N/A	N/A	N/A	N/A
36	Outlook	Stable	Stable	Positive	Stable	Stable	Stable
37							
38							
39			**Fitch Ratings at Year End**				
40		**Current**	**2017**	**2016**	**2015**	**2014**	**2013**
41	**Consumers Energy Company**						
42	Senior Secured Debt	A+	A+	A+	A-	A-	A-
43	Commercial Paper	F-2	F-2	F-2	F-3	N/A	N/A
44	Senior Unsecured Debt	A	A	A	BBB+	BBB+	BBB+
45	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
46	Preferred Stock	BBB+	BBB+	BBB+	BBB-	BBB-	BBB-
47	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
48							
49	**CMS Energy Corporation**						
50	Senior Secured Debt	BBB+	BBB+	BBB+	BBB-	BBB-	BBB-
51	Senior Unsecured Debt	BBB	BBB	BBB	BBB-	BBB-	BB+
52	Junior Subordinated Debt	BB+	N/A	N/A	N/A	N/A	N/A
53	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
54	Preferred Stock	N/A	N/A	N/A	N/A	N/A	N/A
55	Outlook	Stable	Stable	Stable	Stable	Stable	Positive

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recent Utility Corporate Bond Issuances
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-81 (AJD-9)
Page: 1 of 3
Witness: AJDenato
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line	Issue				Amt		Ratings			Issue	
No.	Date	Ticker	Issuer	Type	($mm)	Coupon	Moody's	S&P	Maturity	Spread (bp)	Category
1	01/05/16	ETR	Entergy Arkansas	Secured	325	3.500%	A3	A-	04/01/26	+130	
2	01/08/16	BKH	Black Hills	Unsecured	250	2.500%	Baa1	BBB	01/13/19	+135	
3	01/08/16	BKH	Black Hills	Unsecured	300	3.950%	Baa1	BBB	01/15/26	+185	
4	01/08/16	SO	Alabama Power	Unsecured	400	4.300%	A1	A-	01/02/46	+140	**2**
5	01/12/16	D	Virginia Electric & Power	Unsecured	750	3.150%	A2	A-	01/15/26	+105	
6	02/23/16	PCG	Pacific Gas & Electric	Unsecured	600	2.950%	A3	BBB	03/01/26	+125	
7	02/29/16	AEP	Indiana Michigan Power	Unsecured	400	4.550%	Baa1	BBB	03/15/46	+195	**4**
8	02/29/16	PEG	Public Service Electric & Gas	Secured	300	1.900%	Aa3	A	03/15/21	+70	
9	02/29/16	PEG	Public Service Electric & Gas	Secured	550	3.800%	Aa3	A	03/01/46	+120	**1**
10	03/02/16	EIX	Edison International	Unsecured	400	2.950%	A3	BBB	03/15/23	+130	
11	03/02/16	SO	Georgia Power	Unsecured	325	2.400%	A3	A-	04/01/21	+110	
12	03/02/16	SO	Georgia Power	Unsecured	325	3.250%	A3	A-	04/01/26	+145	
13	03/03/16	XEL	Xcel Energy	Unsecured	400	2.400%	A3	BBB+	03/15/21	+107	
14	03/03/16	XEL	Xcel Energy (re-opening)	Unsecured	350	3.300%	A3	BBB+	06/01/25	+137	
15	03/07/16	NGGLN	Brooklyn Union Gas	Unsecured	500	3.407%	A2	A-	03/10/26	+150	
16	03/07/16	NGGLN	Brooklyn Union Gas	Unsecured	500	4.504%	A2	A-	03/10/46	+180	**2**
17	03/07/16	ETR	Entergy Louisiana (re-opening)	Secured	200	4.950%	A2	A-	01/15/45	+244	**2**
18	03/07/16	IDA	Idaho Power	Secured	120	4.050%	A1	A-	03/01/46	+135	**2**
19	03/07/16	ES	Eversource Energy	Unsecured	250	2.500%	Baa1	A-	03/15/21	+112	
20	03/07/16	ES	Eversource Energy	Unsecured	250	3.350%	Baa1	A-	03/15/26	+147	
21	03/08/16	DUK	Duke Energy Carolinas	Secured	500	2.500%	Aa2	A	03/15/23	+87	
22	03/08/16	DUK	Duke Energy Carolinas	Secured	500	3.875%	Aa2	A	03/15/46	+127	**1**
23	03/08/16	ETR	Entergy Texas	Secured	125	2.550%	Baa1	A-	06/01/21	+125	
24	03/17/16	ETR	Entergy Louisiana	Secured	425	3.250%	A2	A-	04/01/28	+135	
25	03/21/16	EE	El Paso Electric Company (re-opening)	Unsecured	150	5.000%	Baa1	BBB	12/01/44	+200	**4**
26	03/28/16	NEE	NextEra Energy Capital Holdings	Unsecured	500	2.300%	Baa1	BBB+	04/01/19	+130	
27	04/04/16	EXC	Exelon Corporation	Unsecured	300	2.450%	Baa2	BBB-	04/15/21	+125	
28	04/04/16	EXC	Exelon Corporation	Unsecured	750	3.400%	Baa2	BBB-	04/15/26	+165	
29	04/04/16	EXC	Exelon Corporation	Unsecured	750	4.450%	Baa2	BBB-	04/15/46	+190	
30	04/11/16	BRKHEC	Sierra Pacific Power Company	Secured	400	2.600%	A2	A+	05/01/26	+90	
31	04/15/16	OGLETH	Oglethorpe Power	Secured	250	4.250%	Baa1	A	04/01/46	+180	**1**
32	05/02/16	CMS	CMS Energy	Unsecured	300	3.000%	Baa2	BBB	05/15/26	+120	
33	05/03/16	PNW	Arizona Public Service	Unsecured	350	3.750%	A2	A-	05/15/46	+112	**2**
34	05/09/16	DUK	Duke Energy Indiana	Secured	500	3.750%	Aa3	A	05/15/46	+115	**1**
35	05/10/16	ETR	Entergy Mississippi	Secured	375	2.850%	A3	A-	06/01/28	+110	
36	05/10/16	DTE	DTE Electric	Secured	300	3.700%	Aa3	A	06/01/46	+110	**1**
37	05/11/16	ED	Consolidated Edison	Unsecured	500	2.000%	A3	BBB+	05/15/21	+83	
38	05/12/16	PPL	PPL Capital Funding	Unsecured	650	3.100%	Baa2	BBB+	05/15/26	+135	
39	05/12/16	CNL	Cleco Corporate Holdings	Secured	535	3.743%	Baa3	BBB-	05/01/26	+198	
40	05/12/16	CNL	Cleco Corporate Holdings	Secured	350	4.973%	Baa3	BBB-	05/01/46	+238	
41	05/13/16	CNP	CenterPoint Energy Houston Electric	Secured	300	1.850%	A1	A	06/01/21	+67	
42	05/13/16	GAS	AGL Capital	Unsecured	350	3.250%	Baa1	BBB	06/15/26	+158	
43	05/16/16	ETR	Entergy Louisiana	Secured	325	3.050%	A2	A-	06/01/31	+135	
44	05/16/16	SRE	San Diego Gas & Electric	Secured	500	2.500%	Aa2	A+	05/15/26	+78	
45	05/17/16	AES	Indianapolis Power & Light	Secured	350	4.050%	A2	BBB+	05/01/46	+150	**3**
46	05/18/16	ETR	Entergy New Orleans	Unsecured	85	4.000%	Baa2	A-	06/01/26	+213	
47	05/19/16	SO	Southern Company	Unsecured	500	1.550%	Baa2	BBB+	07/01/18	+70	
48	05/19/16	SO	Southern Company	Unsecured	1,000	1.850%	Baa2	BBB+	07/01/19	+80	
49	05/19/16	SO	Southern Company	Unsecured	1,500	2.350%	Baa2	BBB+	07/01/21	+100	
50	05/19/16	SO	Southern Company	Unsecured	1,250	2.950%	Baa2	BBB+	07/01/23	+130	
51	05/19/16	SO	Southern Company	Unsecured	1,750	3.250%	Baa2	BBB+	07/01/26	+145	
52	05/19/16	SO	Southern Company	Unsecured	500	4.250%	Baa2	BBB+	07/01/36	+165	
53	05/19/16	SO	Southern Company	Unsecured	2,000	4.400%	Baa2	BBB+	07/01/46	+180	**3**
54	05/23/16	XEL	Northern States Power - MN	Secured	350	3.600%	Aa3	A	05/15/46	+100	**1**
55	05/23/16	ES	NSTAR Electric	Unsecured	250	2.700%	A2	A	06/01/26	+90	
56	05/31/16	SRE	Southern California Gas Co	Secured	500	2.600%	Aa2	A+	06/15/26	+78	
57	06/06/16	PEG	PSEG Power LLC	Unsecured	700	3.000%	Baa1	BBB+	06/15/21	+180	
58	06/06/16	XEL	Public Service Colorado	Secured	250	3.550%	A1	A	06/15/46	+105	**1**
59	06/08/16	SCG	South Carolina Electric & Gas Company	Secured	425	4.100%	A3	A	06/15/46	+160	**1**
60	06/08/16	SCG	South Carolina Electric & Gas Company (re-opening)	Secured	75	4.500%	A3	A	06/01/64	+210	
61	06/09/16	EMAC	Emera US Finance	Unsecured	500	2.150%	Baa3	BBB	06/15/19	+125	
62	06/09/16	EMAC	Emera US Finance	Unsecured	750	2.700%	Baa3	BBB	06/15/21	+150	
63	06/09/16	EMAC	Emera US Finance	Unsecured	750	3.550%	Baa3	BBB	06/15/26	+190	
64	06/09/16	EMAC	Emera US Finance	Unsecured	1,250	4.750%	Baa3	BBB	06/15/46	+230	**4**
65	06/13/16	WR	Westar Energy	Secured	350	2.550%	A2	A	07/01/26	+95	
66	06/13/16	ETR	Entergy Arkansas (re-opening)	Secured	55	3.500%	A2	A-	04/01/26	+90	
67	06/14/16	ED	Consolidated Edison Co of NY	Unsecured	550	3.850%	A2	A-	06/15/46	+142	**2**
68	06/20/16	EXC	Commonwealth Edison Co	Secured	500	2.550%	A2	A-	06/15/26	+88	
69	06/20/16	AEE	Ameren Missouri (re-opening)	Secured	150	3.650%	A2	A	04/15/45	+120	**1**
70	06/20/16	EXC	Commonwealth Edison Co	Secured	700	3.650%	A2	A-	06/15/46	+120	**2**
71	06/20/16	DUK	Duke Energy Ohio Inc	Secured	250	3.700%	A2	A	06/15/46	+120	**1**
72	06/29/16	ITC	ITC Holdings Co	Unsecured	400	3.250%	Baa2	BBB+	06/30/26	+180	
73	07/11/16	KORGAS	Korea Gas Corp	Unsecured	400	2.250%	Aa2	A+	07/18/26	+90	
74	07/11/16	KORGAS	Korea Gas Corp	Unsecured	500	1.875%	Aa2	A+	07/18/21	+90	
75	07/25/16	DUK	Piedmont Natural Gas	Unsecured	300	3.640%	A2	A	11/01/46	+135	**1**
76	**08/01/16**	**CMS**	**Consumers Energy Co**	**Secured**	**450**	**3.250%**	**A1**	**A**	**08/15/46**	**+105**	**1**
77	08/02/16	NGGLN	KeySpan Gas East Corp	Unsecured	700	2.742%	A2	A-	08/15/26	+120	
78	08/02/16	NGGLN	Massachusetts Electric Co	Unsecured	500	4.004%	A3	A-	08/15/46	+170	**2**
79	08/02/16	D	Dominion Resources	Unsecured	500	1.600%	Baa2	BBB	08/15/19	+85	
80	08/02/16	D	Dominion Resources	Unsecured	400	2.000%	Baa2	BBB	08/15/21	+100	
81	08/02/16	D	Dominion Resources	Unsecured	400	2.850%	Baa2	BBB	08/15/26	+135	
82	08/02/16	XEL	Southwestern Public Service Co	Secured	300	3.400%	A2	A	08/15/46	+110	**1**
83	08/08/16	CNP	CenterPoint Energy Houston Electric	Secured	300	2.400%	A1	A	09/01/26	+83	
84	08/09/16	DUK	Duke Energy	Unsecured	750	1.800%	Baa1	BBB+	09/01/21	+70	
85	08/09/16	DUK	Duke Energy	Unsecured	1,500	2.650%	Baa1	BBB+	09/01/26	+115	
86	08/09/16	DUK	Duke Energy	Unsecured	1,500	3.750%	Baa1	BBB+	09/01/46	+150	**3**
87	08/10/16	BKH	Black Hills	Unsecured	400	3.150%	Baa1	BBB	01/15/27	+165	
88	08/10/16	BKH	Black Hills	Unsecured	300	4.200%	Baa1	BBB	09/15/46	+200	**4**
89	08/15/16	EXC	Baltimore Gas & Electric	Unsecured	500	3.500%	A3	A-	08/15/46	+123	**2**
90	08/15/16	EXC	Baltimore Gas & Electric	Unsecured	350	2.400%	A3	A-	08/15/26	+88	
91	08/15/16	ONCRTX	Oncor Electric Delivery (re-opening)	Secured	175	3.750%	A3	A	04/01/45	+110	**1**
92	08/16/16	ETR	Entergy Corp	Unsecured	750	2.950%	Baa3	BBB	09/01/26	+140	
93	08/25/16	NEE	NextEra Energy Capital Holdings Inc	Unsecured	500	1.649%	Baa1	BBB+	09/01/18	+75	
94	09/06/16	DUK	Duke Energy Florida	Secured	600	3.400%	A1	A	10/01/46	+120	**1**
95	09/07/16	PEG	Public Service Electric & Gas Co	Secured	425	2.250%	Aa3	A	09/15/26	+75	
96	09/08/16	SO	Southern Co Gas Capital Corp	Unsecured	350	2.450%	Baa1	A	10/01/23	+100	
97	09/08/16	SO	Southern Co Gas Capital Corp	Unsecured	550	3.950%	Baa1	A	10/01/46	+165	**1**
98	09/12/16	LNT	Interstate Power and Light Company	Unsecured	300	3.700%	Baa1	A-	09/15/46	+135	**2**
99	09/13/16	WGL	Washington Gas Light Co.	Unsecured	250	3.796%	A1	A+	09/15/46	+133	
100	09/13/16	DUK	Duke Energy Progress	Secured	450	3.700%	Aa3	A	10/15/46	+123	**1**
101	09/14/16	EXC	PECO Energy	Secured	300	1.700%	Aa3	A-	09/15/21	+50	
102	09/15/16	PNW	Arizona Public Service	Unsecured	250	2.550%	A2	A-	09/15/26	+90	
103	09/26/16	AEP	Southwestern Electric Power Co	Unsecured	400	2.750%	Baa2	BBB+	10/01/26	+118	
104											

105 FRN: Floating Rate Note
106 3mL: Three-Month London Interbank Offered Rate (LIBOR)
107 Source: Barclays Bank

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recent Utility Corporate Bond Issuances
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-81 (AJD-9)

Witness: AJDenato
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line	Issue				Amt		Ratings			Issue	
No.	Date	Ticker	Issuer	Type	($mm)	Coupon	Moody's	S&P	Maturity	Spread (bp)	Category
1	09/28/16	ETR	Entergy Louisiana	Secured	400	2.400%	A2	A	10/01/26	+90	
2	09/29/16	DTE	DTE Energy	Unsecured	400	1.500%	A3	BBB	10/01/19	+70	
3	09/29/16	DTE	DTE Energy	Unsecured	600	2.850%	A3	BBB	10/01/26	+130	
4	09/29/16	FTSCN	Fortis Inc	Unsecured	500	2.100%	Baa3	BBB+	10/04/21	+105	
5	09/29/16	FTSCN	Fortis Inc	Unsecured	1,500	3.055%	Baa3	BBB+	10/04/26	+150	
6	10/04/16	SRE	Sempra Energy	Unsecured	500	1.625%	Baa1	BBB+	10/07/19	+72	
7	10/11/16	CFELEC	Comision Federal de Electricidad	Unsecured	1,000	4.750%	Baa1	BBB+	02/23/27	+300	
8	10/31/16	CMS	CMS Energy	Unsecured	275	2.950%	Baa2	BBB	02/15/27	+115	
9	11/03/16	PEG	Public Service Enterprise Group	Unsecured	400	1.600%	Baa2	BBB	11/15/19	+68	
10	11/03/16	PEG	Public Service Enterprise Group	Unsecured	300	2.000%	Baa2	BBB	11/15/21	+78	
11	11/10/16	SO	Southern Power	Unsecured	600	1.950%	Baa1	BBB+	12/15/19	+80	
12	11/10/16	SO	Southern Power	Unsecured	300	2.500%	Baa1	BBB+	12/15/21	+100	
13	11/10/16	SO	Southern Power	Unsecured	400	4.950%	Baa1	BBB+	12/15/46	+210	**3**
14	11/10/16	ED	Consolidated Edison Co of NY	Unsecured	250	2.900%	A2	A-	12/01/26	+80	
15	11/10/16	ED	Consolidated Edison Co of NY	Unsecured	500	4.300%	A2	A-	12/01/56	+140	
16	11/10/16	D	Virginia Electric & Power	Unsecured	400	2.950%	A2	BBB+	11/15/26	+85	
17	11/10/16	D	Virginia Electric & Power	Unsecured	500	4.000%	A2	BBB+	11/15/46	+110	**3**
18	11/14/16	DUK	Duke Energy Carolinas	Secured	600	2.950%	Aa2	A	12/01/26	+75	
19	11/14/16	AWK	American Water Capital	Unsecured	250	3.000%	A3	A	12/01/26	+80	
20	11/14/16	AWK	American Water Capital	Unsecured	300	4.000%	A3	A	12/01/46	+105	**1**
21	11/16/16	AEP	AEP Transmission Company	Unsecured	300	3.100%	A2	BBB+	12/01/26	+90	
22	11/16/16	AEP	AEP Transmission Company	Unsecured	400	4.000%	A2	BBB+	12/01/46	+115	**3**
23	11/21/16	AGR	New York State Electric & Gas	Unsecured	500	3.250%	A3	A-	11/15/26	+100	
24	11/28/16	XEL	Xcel Energy	Unsecured	300	2.600%	A3	BBB+	03/15/22	+80	
25	11/28/16	XEL	Xcel Energy	Unsecured	500	3.350%	A3	BBB+	12/01/26	+105	
26	11/28/16	PCG	Pacific Gas & Electric	Unsecured	250	FRN	A3	BBB+	11/30/17	3mL+20	
27	11/28/16	PCG	Pacific Gas & Electric	Unsecured	400	4.000%	A3	BBB+	12/01/46	+110	**3**
28	11/29/16	AEE	Ameren Illinois (re-opening)	Secured	240	4.150%	A1	A	03/15/46	+100	**1**
29	12/05/16	EXC	Delmarva Power & Light (re-opening)	Secured	175	4.150%	A2	A	05/15/45	+105	
30	12/12/16	D	Dominion Resources Inc	Unsecured	250	1.875%	Baa2	BBB	12/15/18	+76	
31	01/03/17	DUK	Duke Energy Florida	Secured	250	1.850%	A1	A	01/15/20	+40	
32	01/03/17	DUK	Duke Energy Florida	Secured	650	3.200%	A1	A	01/15/27	+75	
33	01/09/17	CNP	CenterPoint Energy Houston Electric	Secured	300	3.000%	A1	A	02/01/27	+70	
34	01/09/17	D	Dominion Resources	Unsecured	400	1.875%	Baa2	BBB	01/15/19	+72	
35	01/09/17	D	Dominion Resources	Unsecured	400	2.750%	Baa2	BBB	01/15/22	+90	
36	01/23/17	BRKHEC	MidAmerican Energy Co	Secured	375	3.100%	Aa2	A+	05/01/27	+70	
37	01/23/17	BRKHEC	MidAmerican Energy Co	Secured	475	3.950%	Aa2	A+	08/01/47	+95	
38	02/08/17	CMS	CMS Energy	Unsecured	350	3.450%	Baa2	BBB	08/15/27	+110	
39	**02/15/17**	**CMS**	**Consumers Energy Co**	**Secured**	**350**	**3.950%**	**A1**	**A**	**07/15/47**	**+88**	**1**
40	02/27/17	WR	Westar Energy	Secured	300	3.100%	A2	A	04/01/27	+78	
41	02/27/17	SO	Alabama Power	Unsecured	550	2.450%	A1	A-	03/30/22	+60	
42	02/27/17	ED	Consolidated Edison	Unsecured	400	2.000%	A3	BBB+	03/15/20	+55	
43	02/28/17	SO	Georgia Power	Unsecured	450	2.000%	A3	A-	03/30/20	+53	
44	02/28/17	SO	Georgia Power	Unsecured	400	3.250%	A3	A-	03/30/27	+90	
45	03/02/17	ES	Connecticut Light & Power	Secured	300	3.200%	A2	A+	03/15/27	+75	
46	03/02/17	ES	Eversource Energy	Unsecured	300	2.750%	Baa1	A-	03/15/22	+75	
47	03/06/17	GXP	Great Plains Energy	Unsecured	750	2.500%	Baa3	BBB	03/09/20	+95	
48	03/06/17	GXP	Great Plains Energy	Unsecured	1,150	3.150%	Baa3	BBB	04/01/22	+115	
49	03/06/17	GXP	Great Plains Energy	Unsecured	1,400	3.900%	Baa3	BBB	04/01/27	+145	
50	03/06/17	GXP	Great Plains Energy	Unsecured	1,000	4.850%	Baa3	BBB	04/01/47	+175	**4**
51	03/07/17	PCG	Pacific Gas & Electric	Unsecured	400	3.300%	A3	BBB+	03/15/27	+83	
52	03/07/17	PCG	Pacific Gas & Electric (re-opening)	Unsecured	200	4.000%	A3	BBB+	12/01/46	+100	**3**
53	03/07/17	EXC	Exelon Generation (re-opening)	Unsecured	250	2.950%	Baa2	BBB	01/15/20	+100	
54	03/07/17	EXC	Exelon Generation	Unsecured	500	3.400%	Baa2	BBB	02/28/22	+140	
55	03/08/17	DTE	DTE Energy	Unsecured	500	3.800%	Baa1	BBB	03/15/27	+128	
56	03/13/17	D	Virginia Electric & Power	Unsecured	750	3.500%	A2	BBB+	03/13/27	+90	
57	03/16/17	PNW	Arizona Public Service (re-opening)	Unsecured	250	4.350%	A2	A-	11/15/45	+110	**2**
58	03/21/17	EIX	Southern California Edison	Secured	700	4.000%	Aa3	A	04/01/47	+95	**1**
59	03/22/17	EIX	Edison International	Unsecured	400	2.125%	A3	BBB	04/15/20	+63	
60	03/22/17	DUK	Duke Energy Ohio (reopening)	Secured	100	3.700%	A2	A	06/15/46	+107	**1**
61	03/28/17	OGE	Oklahoma Gas & Electric	Unsecured	300	4.150%	A1	A-	04/01/47	+115	**2**
62	03/29/17	EXC	Exelon Corporation (re-marketing)	Unsecured	1,150	3.497%	Baa3	BBB-	06/01/22	+150	
63	04/18/17	NRUC	National Rural Utilities Coop Finance	Secured	450	2.400%	A2	A	04/25/22	+70	
64	04/18/17	NRUC	National Rural Utilities Coop Finance	Secured	350	3.050%	A2	A	04/25/27	+90	
65	04/25/17	NEE	NextEra Energy Capital Holdings	Unsecured	1,250	3.550%	Baa1	BBB+	05/01/27	+125	
66	04/26/17	CHGRID	State Grid Overseas Investment	Unsecured	900	2.250%	Aa3	AA-	05/04/20	+85	
67	04/26/17	CHGRID	State Grid Overseas Investment	Unsecured	1,250	2.750%	Aa3	AA-	05/04/22	+95	
68	04/26/17	CHGRID	State Grid Overseas Investment	Unsecured	2,350	3.500%	Aa3	AA-	05/04/27	+120	
69	04/26/17	CHGRID	State Grid Overseas Investment	Unsecured	500	4.000%	Aa3	AA-	05/04/47	+103	
70	04/27/17	SOPOWZ	China Southern Power Grid	Unsecured	600	2.750%	Aa3	AA-	05/08/22	+100	
71	04/27/17	SOPOWZ	China Southern Power Grid	Unsecured	900	3.500%	Aa3	AA-	05/08/27	+130	
72	05/02/17	PEG	Public Service Electric & Gas	Secured	425	3.000%	Aa3	A	05/15/27	+73	
73	05/04/17	SO	Southern Co Gas Capital Corp	Unsecured	450	4.400%	Baa1	A-	05/30/47	+140	**2**
74	05/08/17	AEP	Appalachian Power	Unsecured	325	3.380%	Baa1	A-	05/15/27	+98	**1**
75	05/08/17	PPL	PPL Electric Utilities	Secured	475	2.950%	A1	A	06/01/47	+98	
76	05/09/17	ETR	Entergy Arkansas (reopening)	Secured	220	3.500%	A2	A	04/01/26	+80	
77	05/09/17	FE	Monongahela Power	Secured	250	3.550%	A3	BBB+	05/15/27	+115	
78	05/10/17	ES	NSTAR Electric	Unsecured	350	3.200%	A2	A	05/15/27	+80	
79	05/11/17	NI	NiSource Finance Corp	Unsecured	1,000	3.490%	Baa2	BBB+	05/15/27	+110	
80	05/11/17	NI	NiSource Finance Corp	Unsecured	1,000	4.375%	Baa2	BBB+	05/15/47	+135	**3**
81	05/15/17	D	Dominion Energy (re-marketing)	Unsecured	1,000	1.500%	Baa3	BBB	07/01/20	+105	
82	05/15/17	SO	Gulf Power	Unsecured	300	3.300%	A2	A-	05/30/27	+98	
83	05/15/17	EXC	Potomac Electric Power (re-opening)	Secured	200	4.150%	A2	A	03/15/43	+100	
84	05/17/17	AGR	Rochester Gas & Electric	Secured	300	3.100%	A1	A-	06/01/27	+90	
85	05/17/17	ETR	Entergy Louisiana	Secured	450	3.120%	A2	A	09/01/27	+90	
86	05/22/17	ENELIM	Enel Finance International	Unsecured	2,000	2.875%	Baa2	BBB	05/25/22	+115	
87	05/22/17	ENELIM	Enel Finance International	Unsecured	2,000	3.625%	Baa2	BBB	05/25/27	+150	
88	05/22/17	ENELIM	Enel Finance International	Unsecured	1,000	4.750%	Baa2	BBB	05/25/47	+185	**4**
89	06/05/17	SRE	San Diego Gas & Electric	Secured	400	3.750%	Aa2	A+	06/01/47	+93	
90	06/05/17	ATO	Atmos Energy Corp	Unsecured	500	3.000%	A2	A-	06/15/27	+85	
91	06/05/17	ATO	Atmos Energy Corp (re-opening)	Unsecured	250	4.125%	A2	A-	10/15/44	+105	
92	06/05/17	ED	Consolidated Edison Co of NY	Unsecured	500	3.875%	A2	A-	06/15/47	+105	**2**
93	06/06/17	AEE	Ameren Missouri	Secured	400	2.950%	A2	A	06/15/27	+85	
94	06/06/17	SRE	Sempra Energy	Unsecured	750	3.250%	Baa1	BBB+	06/15/27	+115	
95	06/12/17	XEL	Public Service Co. of Colorado	Secured	400	3.800%	A1	A	06/15/47	+95	**1**
96	06/13/17	GXP	Kansas City Power & Light	Unsecured	300	4.200%	Baa1	BBB+	06/15/47	+135	**3**
97	06/19/17	FE	FirstEnergy Corp	Unsecured	500	2.850%	Baa3	BB+	07/15/22	+110	
98	06/19/17	FE	FirstEnergy Corp	Unsecured	1,500	3.900%	Baa3	BB+	07/15/27	+175	
99	06/19/17	FE	FirstEnergy Corp	Unsecured	1,000	4.850%	Baa3	BB+	07/15/47	+210	
100	06/21/17	EDPPL	EDP Finance BV	Unsecured	1,000	3.625%	Baa3	BB+	07/15/24	+170	
101	06/26/17	AEP	Indiana Michigan Power Co	Unsecured	300	3.750%	Baa1	A-	07/01/47	+110	**2**
102	07/19/17	DQE	Duquesne Light Holdings	Unsecured	325	3.616%	Baa3	BBB-	08/01/27	+135	
103	07/31/17	NGGLN	Boston Gas Company	Unsecured	500	3.150%	A3	A-	08/01/27	+87	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recent Utility Corporate Bond Issuances
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-81 (AJD-9)
Page: 3 of 3
Witness: AJDenato
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line	Issue				Amt		Ratings			Issue	
No.	Date	Ticker	Issuer	Type	($mm)	Coupon	Moody's	S&P	Maturity	Spread (bp)	Category
1	07/31/17	DTE	DTE Electric	Secured	440	3.750%	Aa3	A	08/15/47	+85	1
2	08/02/17	XEL	Southwestern Public Service Co	Secured	450	3.700%	A2	A	08/15/47	+88	1
3	08/03/17	SO	Georgia Power	Unsecured	500	2.000%	A3	A-	09/08/20	+53	
4	08/07/17	AWK	American Water	Unsecured	600	2.950%	A3	A	09/01/27	+73	
5	08/07/17	AWK	American Water	Unsecured	750	3.750%	A3	A	09/01/47	+93	1
6	08/07/17	CNP	Centerpoint Energy	Unsecured	500	2.500%	Baa1	BBB+	09/01/22	+70	
7	08/07/17	DUK	Duke Energy	Unsecured	500	2.400%	Baa1	BBB+	08/15/22	+63	
8	08/07/17	DUK	Duke Energy	Unsecured	750	3.150%	Baa1	BBB+	08/15/27	+93	
9	08/07/17	DUK	Duke Energy	Unsecured	500	3.950%	Baa1	BBB+	08/15/47	+113	3
10	08/08/17	OGE	Oklahoma Gas & Electric	Unsecured	300	3.850%	A1	A-	08/15/47	+100	2
11	08/08/17	ES	Connecticut Light & Power (re-opening)	Secured	225	4.300%	A2	A+	04/15/44	+85	
12	08/16/17	EXC	Commonwealth Edison Co	Secured	350	2.950%	A1	A-	08/15/27	+75	
13	08/16/17	EXC	Commonwealth Edison Co	Secured	650	3.750%	A1	A-	08/15/47	+95	2
14	08/17/17	EIX	Edison International	Unsecured	400	2.400%	A3	BBB	09/15/22	+70	
15	08/21/17	CNP	CenterPoint Energy Resources	Unsecured	300	4.100%	Baa2	A-	09/01/47	+138	2
16	08/21/17	EXC	Baltimore Gas & Electric	Unsecured	300	3.750%	A3	A-	08/15/47	+103	2
17	08/23/17	NRUC	National Rural Utilities Cooperative Finance	Unsecured	350	2.300%	A2	A	09/15/22	+55	
18	09/05/17	DUK	Duke Energy Progress	Secured	300	FRN	Aa3	A	09/08/20	3mL+18	
19	09/05/17	DUK	Duke Energy Progress	Secured	500	3.600%	Aa3	A	09/15/47	+92	1
20	09/05/17	EIX	Southern California Edison (re-opening)	Secured	300	4.000%	Aa3	A	04/01/47	+90	1
21	09/05/17	NI	NiSource Finance Corp	Unsecured	750	3.950%	Baa2	BBB+	03/30/48	+128	3
22	09/05/17	FE	Pennsylvania Electric Company	Unsecured	300	3.250%	Baa1	BBB-	03/15/28	+118	
23	09/06/17	XEL	Northern States Power - MN	Secured	600	3.600%	Aa3	A	09/15/47	+93	1
24	09/06/17	PPL	PPL Capital Funding	Unsecured	500	4.000%	Baa2	BBB+	09/15/47	+135	3
25	09/06/17	PNW	Arizona Public Service	Unsecured	300	2.950%	A2	A-	09/15/27	+85	
26	09/06/17	NWN	Northwest Natural Gas	Secured	25	2.822%	A1	AA-	09/13/27	+75	
27	09/06/17	NWN	Northwest Natural Gas	Secured	75	3.685%	A1	AA-	09/13/47	+100	
28	09/11/17	D	Virginia Electric & Power (reopening)	Unsecured	200	2.750%	A2	BBB+	03/15/23	+70	
29	09/11/17	D	Virginia Electric & Power	Unsecured	550	3.800%	A2	BBB+	09/15/47	+110	3
30	09/11/17	EXC	PECO Energy	Secured	325	3.700%	Aa3	A-	09/15/47	+98	2
31	09/13/17	WGL	Washington Gas & Light (reopening)	Unsecured	200	3.796%	A1	A	09/15/46	+110	1
32	09/13/17	FENIPE	Fenix Power Peru	Unsecured	340	4.317%	Baa3	BBB-	09/20/27	+213	
33	09/18/17	ONCRTX	Oncor Electric Delivery	Secured	325	3.800%	A3	A	09/30/47	+100	1
34	09/18/17	AEP	AEP Texas	Unsecured	400	2.400%	Baa1	A-	10/02/22	+60	
35	09/18/17	AEP	AEP Texas	Unsecured	300	3.800%	Baa1	A-	10/01/47	+105	2
36	09/25/17	AEP	AEP Transmission Company (reopening)	Unsecured	125	3.100%	A2	A-	12/01/26	+77	
37	09/25/17	AEP	AEP Transmission Company	Unsecured	500	3.750%	A2	A-	12/01/47	+100	2
38	10/02/17	ES	NSTAR Electric (reopening)	Unsecured	350	3.200%	A2	A	05/15/27	+72	
39	10/02/17	ES	Eversource Energy (reopening)	Unsecured	450	2.750%	Baa1	A-	03/15/22	+57	
40	10/02/17	ES	Eversource Energy	Unsecured	450	2.900%	Baa1	A-	10/01/24	+77	
41	10/02/17	LNT	Wisconsin Power & Light	Unsecured	300	3.050%	A2	A	10/15/27	+75	
42	10/02/17	FE	Cleveland Electric Illuminating	Unsecured	350	3.500%	Baa3	BBB-	04/01/28	+120	
43	10/03/17	ENELIM	Enel Finance International	Unsecured	1,250	2.750%	Baa2	BBB	04/06/23	+90	
44	10/03/17	ENELIM	Enel Finance International	Unsecured	1,250	3.500%	Baa2	BBB	04/06/28	+132	
45	10/03/17	ENELIM	Enel Finance International (reopening)	Unsecured	500	4.750%	Baa2	BBB	05/25/47	+147	4
46	10/10/17	SRE	Sempra Energy	Unsecured	850	FRN	Baa1	BBB+	03/15/21	3mL+45	
47	11/01/17	NEE	Florida Power & LIght	Secured	750	FRN	A1	A-	11/06/20	3mL+28	
48	11/02/17	SO	Alabama Power	Unsecured	550	3.700%	A1	A-	12/01/47	+88	2
49	11/02/17	PEG	Public Service Enterprise Group	Unsecured	700	2.650%	Baa2	BBB	11/15/22	+68	
50	11/08/17	AEP	American Electric Power	Unsecured	500	2.150%	Baa1	BBB+	11/13/20	+45	
51	11/08/17	AEP	American Electric Power	Unsecured	500	3.200%	Baa1	BBB+	11/13/27	+90	
52	11/08/17	NI	NiSource Finance Corp	Unsecured	500	2.650%	Baa2	BBB+	11/17/22	+68	
53	11/09/17	ITC	ITC Holdings Co	Unsecured	500	2.700%	Baa2	A-	11/15/22	+72	
54	11/09/17	ITC	ITC Holdings Co	Unsecured	500	3.350%	Baa2	A-	11/15/27	+102	
55	11/09/17	DUK	Duke Energy Carolinas	Secured	550	3.700%	Aa2	A	12/01/47	+90	1
56	11/09/17	LNT	Interstate Power and Light Company (reopening)	Unsecured	250	3.250%	Baa1	A-	12/01/24	+75	
57	11/09/17	ETR	Entergy Mississippi	Secured	150	3.250%	A2	A	12/01/27	+95	
58	11/09/17	SO	Southern Power	Unsecured	525	FRN	Baa2	BBB+	12/20/20	3mL+55	
59	11/13/17	NEE	Florida Power & Light	Secured	700	3.700%	Aa2	A	12/01/47	+88	1
60	11/13/17	ED	Consolidated Edison Co of NY	Unsecured	350	3.125%	A2	A-	11/15/27	+73	
61	11/13/17	ED	Consolidated Edison Co of NY	Unsecured	350	4.000%	A2	A-	11/15/57	+115	
62	11/14/17	ETR	Entergy Texas	Secured	150	3.450%	Baa1	A	12/01/27	+110	
63	11/27/17	WGL	WGL Holdings	Unsecured	300	FRN	A3	A	11/29/19	3mL+40	
64	11/27/17	PCG	Pacific Gas & Electric	Unsecured	500	FRN	P-1	A-2	11/28/18	3mL+23	
65	11/27/17	PCG	Pacific Gas & Electric	Unsecured	1,150	3.300%	A2	A-	12/01/27	+100	
66	11/27/17	PCG	Pacific Gas & Electric	Unsecured	850	3.950%	A2	A-	12/01/47	+120	2
67	11/27/17	XEL	Northern States Power - WI	Secured	100	3.750%	Aa3	A	12/01/47	+100	1
68	11/28/17	PNW	Pinnacle West Capital	Unsecured	300	2.250%	A3	BBB+	11/30/20	+43	
69	11/30/17	NGGLN	New England Power Co.	Unsecured	400	3.800%	A3	A-	12/30/47	+97	2
70	12/04/17	PEG	Public Service Electric & Gas	Secured	350	3.600%	Aa3	A	12/01/47	+82	1
71	01/02/18	BRKHEC	Berkshire Hathaway Energy Company	Unsecured	450	2.375%	A3	A-	01/15/21	+38	
72	01/02/18	BRKHEC	Berkshire Hathaway Energy Company	Unsecured	400	2.800%	A3	A-	01/15/23	+55	
73	01/02/18	BRKHEC	Berkshire Hathaway Energy Company	Unsecured	600	3.250%	A3	A-	04/15/28	+83	
74	01/02/18	BRKHEC	Berkshire Hathaway Energy Company	Unsecured	750	3.800%	A3	A-	07/15/48	+103	2
75	01/03/18	ES	Eversource Energy (reopening)	Unsecured	200	2.500%	Baa1	A	03/15/21	+42	
76	01/03/18	ES	Eversource Energy	Unsecured	450	3.300%	Baa1	A	01/15/28	+85	
77	01/09/18	SRE	Sempra Energy	Unsecured	500	FRN	Baa1	BBB+	07/15/19	3mL+25	
78	01/09/18	SRE	Sempra Energy	Unsecured	500	2.400%	Baa1	BBB+	02/01/20	+50	
79	01/09/18	SRE	Sempra Energy	Unsecured	700	FRN	Baa1	BBB+	01/15/21	3mL+50	
80	01/09/18	SRE	Sempra Energy	Unsecured	500	2.900%	Baa1	BBB+	02/01/23	+65	
81	01/09/18	SRE	Sempra Energy	Unsecured	1,000	3.400%	Baa1	BBB+	02/01/28	+93	
82	01/09/18	SRE	Sempra Energy	Unsecured	1,000	3.800%	Baa1	BBB+	02/01/38	+98	
83	01/09/18	SRE	Sempra Energy	Unsecured	800	4.000%	Baa1	BBB+	02/01/48	+118	3
84	01/18/18	AEP	Southwestern Electric Power Co	Unsecured	450	3.850%	Baa2	A-	02/01/48	+97	2
85	01/29/18	BRKHEC	MidAmerican Energy Co	Secured	700	3.650%	Aa2	A+	08/01/48	+75	
86	02/12/18	EXC	Commonwealth Edison Co	Secured	800	4.000%	A1	A-	03/01/48	+85	2
87	02/15/18	EXC	PECO Energy	Secured	325	3.900%	Aa3	A-	03/01/48	+77	2
88	02/26/18	NEE	Florida Power & Light	Secured	1,000	3.950%	Aa2	A-	03/01/48	+82	2
89	02/26/18	CNP	CenterPoint Energy Houston Electric	Secured	400	3.950%	A1	A	03/01/48	+82	1
90	02/26/18	DUK	Duke Energy Carolinas	Secured	500	3.050%	Aa2	A	03/15/23	+47	
91	02/26/18	DUK	Duke Energy Carolinas	Secured	500	3.950%	Aa2	A	03/15/48	+82	1
92	02/26/18	GXP	Kansas City Power & Light	Unsecured	300	4.200%	Baa1	BBB+	03/15/48	+105	3
93	02/28/18	EIX	Southern California Edison	Secured	450	2.900%	Aa3	A	03/01/21	+50	
94	02/28/18	EIX	Southern California Edison	Secured	400	3.650%	Aa3	A	03/01/28	+80	
95	02/28/18	EIX	Southern California Edison	Secured	400	4.125%	Aa3	A	03/01/48	+100	1

	Average Spread 2016-2018
(1) 30-year Debt Issuance A Rated Securities	**+107**
(2) 30-year Debt Issuance A- Rated Securities	**+119**
(3) 30-year Debt Issuance BBB+ Rated Securities	**+132**
(4) 30-year Debt Issuance BBB Rated Securities	**+190**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer Company Equity Ratios
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-82 (AJD-10)

Witness: AJDenato
Date: May 2018

Source: S&P Global Market Intelligence (SNL Energy)
Debt Unadjusted

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Dec 31, 2016 (amounts in $000s)				**% of Total**		
Line No.	**Company Name**	**Long-Term Debt**	**Preferred Stock**	**Common Stock**	**Total**	**Long-Term Debt**	**Preferred Stock**	**Common Stock**
1	Alliant Energy Corporation	3,894,067	200,000	3,998,292	8,092,359	48.1%	2.5%	49.4%
2								
3	Ameren Corporation	6,670,338	142,392	7,458,688	14,271,418	46.7%	1.0%	52.3%
4								
5	American Electric Power Company	17,425,210	0	16,458,465	33,883,675	51.4%	0.0%	48.6%
6								
7	Dominion Resources, Inc.	14,766,323	0	21,141,217	35,907,540	41.1%	0.0%	58.9%
8								
9	DTE Energy Company	7,126,852	0	7,440,630	14,567,482	48.9%	0.0%	51.1%
10								
11	NiSource Inc.	4,013,616	0	4,971,899	8,985,515	44.7%	0.0%	55.3%
12								
13	OGE Energy Corp.	2,545,952	0	3,252,113	5,798,065	43.9%	0.0%	56.1%
14								
15	Pinnacle West Capital Corp.	4,080,501	0	4,905,680	8,986,181	45.4%	0.0%	54.6%
16								
17	Portland General Electric Company	2,360,879	0	2,343,881	4,704,760	50.2%	0.0%	49.8%
18								
19	WEC Energy Group, Inc.	5,555,350	30,450	7,206,417	12,792,217	43.4%	0.2%	56.3%
20								
21	Xcel Energy Inc.	11,286,703	0	13,369,966	24,656,669	45.8%	0.0%	54.2%
22								
23								
24	Average Proxy Group					46.3%	0.3%	53.3%

Column (b) = Company ROE witness Srikanth Maddipati's proxy group from Exhibit A-14 (SM-1), Schedule D-5, page 1.
Columns (c), (d) & (e): Balances at December 31, 2016 per S&P Global Market Intelligence (formerly SNL Energy).
Data for each company is equal to the sum of the regulated subsidiaries of each proxy group company (where applicable).
Column (f) = sum (c), (d), (e).
Column (g) = (c)/(f).
Column (h) = (d)/(f).
Column (i) = (e)/(f).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer Company Equity Ratios
for the Projected Year Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-82 (AJD-10)
Page: 2 of 2
Witness: AJDenato
Date: May 2018

Source: S&P Global
Debt Adjusted

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Dec 31, 2016 (amounts in $millions)				**% of Total**		
Line No.	**Company Name**	**Long-Term Debt**	**Preferred Stock**	**Common Stock**	**Total**	**Long-Term Debt**	**Preferred Stock**	**Common Stock**
1	Alliant Energy Corporation	4,745	100	3,980	8,825	53.8%	1.1%	45.1%
2								
3	Ameren Corporation	6,826	142	6,982	13,950	48.9%	1.0%	50.0%
4								
5	American Electric Power Company	4,623	0	3,366	7,989	57.9%	0.0%	42.1%
6								
7	Dominion Resources, Inc.	12,771	0	11,299	24,070	53.1%	0.0%	46.9%
8								
9	DTE Energy Company	8,914	0	7,515	16,429	54.3%	0.0%	45.7%
10								
11	NiSource Inc.	2,329	0	2,156	4,485	51.9%	0.0%	48.1%
12								
13	OGE Energy Corp.	2,840	0	3,252	6,092	46.6%	0.0%	53.4%
14								
15	Pinnacle West Capital Corp.	4,594	0	4,906	9,500	48.4%	0.0%	51.6%
16								
17	Portland General Electric Company	3,059	0	2,344	5,403	56.6%	0.0%	43.4%
18								
19	WEC Energy Group, Inc.	14,466	15	10,019	24,501	59.0%	0.1%	40.9%
20								
21	Xcel Energy Inc.	13,210	0	12,557	25,767	51.3%	0.0%	48.7%
22								
23								
24	Average Proxy Group					52.9%	0.2%	46.9%
25								
26								
27	Consumers Energy	7,232	37	5,902	13,171	54.9%	0.3%	44.8%

Column (b) = Company ROE witness Srikanth Maddipati's proxy group from Exhibit A-14 (SM-1), Schedule D-5, page 1.
Columns (c), (d) & (e): S&P Global.
Column (f) = sum (c), (d), (e).
Column (g) = (c)/(f).
Column (h) = (d)/(f).
Column (i) = (e)/(f).
*S&P does not make adjustments to debt for these companies and they were excluded from this analysis.

Regulatory Saving Initiatives Summary

Description	Amount ($M)	Rate Case	Filing Date
OPEB Medicare Exchanges	$46	GRC U-18424 ERC U-20134	August 2017 May 2018
Classic 7 Plant Closing	$30	ERC U-17990	March 2016
Uncollectible Expense	$30	GRC U-18424 ERC U-18322	August 2017 March 2017
Pole Top Capitalization	$30	ERC U-17990	March 2016
Pension Split	$24	GRC U-18424 ERC U-20134	August 2017 May 2018
Vehicle Depreciation	$21	GRC U-18424 ERC U-20134	August 2017 May 2018
Zeeland & Campbell Property Tax Savings	$11	ERC U-18322	March 2017
New Benefits Accounting Standard	$8	GRC U-18424 ERC U-20134	August 2017 May 2018
MISO Tax Savings	$4	GRC U-18424 ERC U-20134	August 2017 May 2018
Workers' Compensation Expense	$3	GRC U-18424 ERC U-18322	August 2017 March 2017
Accounting Cost Reductions	$1.5	GRC U-18424 ERC U-18322	August 2017 March 2017

Consumers Energy
Count on Us

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

EXHIBITS

OF

JOSH R. HALL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Information Technology O&M Expenses
For the Years 2017, 2018, and Test Year 12 Months Ending December 31, 2019
($000)

Case No.: U-20134
Exhibit No.: A-83 (JRH-1)
Page: 1 of 1
Witness: JRHall
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Months Ending 12/31/2019**	**Source**
1	**Operations**	**$ 37,021**	**$ 41,472**	**$ 40,108**	
2	Labor	8,392	7,516	7,269	
3	Contracts	27,026	31,908	30,859	
4	Business Expense	1,418	1,845	1,784	
5	Material	186	203	196	
6	**Origination**	**$ 499**	**$ 596**	**$ 577**	
7	Labor	373	596	577	
8	Contracts	125	0	0	
9	**O&M Investments**	**$ 14,890**	**$ 13,352**	**$ 13,190**	
10	Labor	3,067	5,163	5,202	
11	Contracts	11,385	8,189	7,988	
12	Business Expense	162	0	0	
13	Material	275	0	0	
14	**Total Expense**	**$ 52,410**	**$ 55,420**	**$ 53,875**	

Schedule B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Information Technology
Summary of Actual and Projected Electric Capital Expenditures
($000)

Case No.: U-20134
Exhibit No.: A-12 (JRH-2)
Schedule: B-5.6
Page: 1 of 1
Witness: JRHall
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Year			Projected Test Year
Line No.	Description	12 Mos Ended 12/31/2017	12 Mos Ending 12/31/2018	12 Mos Ending 12/31/2019	24 Mos Ending 12/31/2019	12 Mos Ending 12/31/2019
1	**Upgrades & Replacements (Enterprise)**	**29,530**	**41,515**	**45,953**	**87,467**	**45,953**
	Software	307	776	1,555	2,331	1,555
	Materials	9,518	20,456	25,045	45,501	25,045
	Labor	3,137	4,384	6,862	11,246	6,862
	Contractor Costs	14,460	10,148	7,043	17,191	7,043
	Engineering	-	-	-	-	-
	Overhead & Others	2,108	5,736	4,828	10,564	4,828
	Contingency	-	15	619	634	619
2	**Upgrades & Replacements (Business Partner)**	**3,097**	**5,760**	**791**	**6,552**	**791**
	Software	1,233	82	283	365	283
	Materials	234	152	203	355	203
	Labor	483	1,164	130	1,294	130
	Contractor Costs	864	2,770	-	2,770	-
	Engineering	-	-	-	-	-
	Overhead & Others	283	1,593	109	1,702	109
	Contingency	-	-	66	66	66
3	**Security**	**4,806**	**9,386**	**9,212**	**18,598**	**9,212**
	Software	369	331	762	1,093	762
	Materials	1,312	308	2,771	3,079	2,771
	Labor	631	2,638	1,292	3,930	1,292
	Contractor Costs	2,013	1,524	1,968	3,492	1,968
	Engineering	-	-	-	-	-
	Overhead & Others	481	4,586	2,314	6,900	2,314
	Contingency	-	-	105	105	105
4	**IT Service Delivery**	**2,375**	**4,481**	**3,676**	**8,157**	**3,676**
	Software	399	-	31	31	31
	Materials	(379)	470	82	552	82
	Labor	293	637	1,288	1,925	1,288
	Contractor Costs	1,844	1,427	1,119	2,546	1,119
	Engineering	-	-	-	-	-
	Overhead & Others	217	1,928	1,065	2,994	1,065
	Contingency	-	19	90	109	90
5	**Enhancements**	**2,225**	**2,614**	**4,261**	**6,875**	**4,261**
	Software	97	-	70	70	70
	Materials	-	-	17	17	17
	Labor	670	159	946	1,105	946
	Contractor Costs	1,109	721	97	818	97
	Engineering	-	-	-	-	-
	Overhead & Others	349	1,734	3,131	4,866	3,131
	Contingency	-	-	-	-	-
6	**BP Functionality**	**21,820**	**21,181**	**14,735**	**35,916**	**14,735**
	Software	1,054	587	585	1,172	585
	Materials	4,090	1,496	625	2,121	625
	Labor	3,923	5,442	5,230	10,672	5,230
	Contractor Costs	9,673	4,048	4,537	8,585	4,537
	Engineering	-	-	-	-	-
	Overhead & Others	3,080	9,120	3,758	12,878	3,758
	Contingency	-	488	-	488	-
7	**Architecture**	**774**	**-**	**-**	**-**	**-**
	Software	25	-	-	-	-
	Materials	58	-	-	-	-
	Labor	390	-	-	-	-
	Contractor Costs	163	-	-	-	-
	Engineering	-	-	-	-	-
	Overhead & Others	139	-	-	-	-
	Contingency	-	-	-	-	-
	Total Capital	**64,627**	**84,937**	**78,628**	**163,565**	**78,628**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures
For the years 2017 through 2019

Information Technology Department

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
1	2017	Application Performance Monitoring	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Implement an end to end systems performance monitoring solution that provides the following capabilities: --Application Performance Monitoring --Infrastructure and Network Performance Monitoring --Customer Experience and End User Monitoring	• Real-time contact center response time reporting vs. hourly reporting • Improved user interface - dashboard view vs. emailed report • Visibility into the smart energy application network • Targeted troubleshooting and faster root cause analysis • Deep-dive analytics and drill-down capability • Exception alerting capability • Auto-discovery, low configuration solutions (i.e., less administrative work) • Reduce Waste	18-Mar	(1.00)	118,710	0	0	5,519	111,628	0	1,563	0
2	2017	ARP - Collaboration Asset Refresh	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is for the refresh of the Company's Collaborative tools such as Telephony Systems, Video Conference Systems and Digital Whiteboard systems.	This project provides value by insuring the tools used by employees to communicate and conduct business activities are modern and reliable. Customers benefit as the business is more effective when communication systems are reliable and available.	17-Dec	(0.95)	835,667	30,826	563,202	104,075	76,168	0	61,395	0
3	2017	ARP - Critical Infrastructure Support	Upgrades & Replacements (Enterprise)	Network	Electric T&D, Gas T&D, Generation	Asset refresh project for infrastructure supported by CIS. Replace assorted critical infrastructure due to obsolescence hardware as identified per 5 year budget planning/forecast. IT provides both hardware and labor funding.	The requirement is to replace and upgrade the in scope items with current technologies. The project will replace functionality without necessarily doing a like-for-like replacement of the asset. For example, instead of replacing 20 servers with 20 servers, converged infrastructure will be implemented.	20-Dec	(1.04)	380,879	0	344,938	24,846	833	0	10,261	0
4	2017	ARP - Field Device Asset Management (FDAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy field devices on a four-year refresh cycle. Field Devices typically last 4 years before we start having technical issues with the units. Completing the refresh will mitigate potential costs for hardware repairs, and allow Field Workers to complete their job tasks.	Field Workers require these rugged devices to complete their daily job tasks in support of our customers. Benefits of the ARP Field Device Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Reduced potential impact to our customers - Increased system performance such as speed, battery life, etc... - Increased CE employee opportunity to exceed expectations of our customers. - Less impact on future years for capital refresh requests, just pushing the issue if we delay	17-Dec	(1.09)	1,208,273	0	1,191,008	9,398	4,052	0	3,815	0
5	2017	ARP - IT Facilities	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project addresses the physical facilities (space, equipment racks, communications cabling, etc.) and environmental needs in the Company's two Data Centers and IT Rooms.	The project will insure that the Company's IT Systems that provide Customer services can be reliably hosted from the internal Data Centers.	17-Nov	(1.08)	-986	0	-433	-481	0	0	-73	0
6	2017	ARP - Multimedia	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	UCC will achieve the integration of multiple real-time communication services (e.g. chat, telephony, video) along with non-real-time communication services (e.g. voicemail, email, SMS) . This entails products and configuration necessary to connect two Microsoft solutions, Enterprise Voice and Unified Messaging with our telecommunication systems.	• Employees will be able to receive all calls to their corporate number on their Lync client. Their Lync client can exist on a laptop/desktop, tablet, or smart phone. • Employees will be able to call any company or external phone from their Lync 2013 clients. • Audio bridge numbers will be automatically added to meetings. Employees will be able to join these meetings via Lync client or phone. • Meetings will be able to call participates when the meeting starts. • Employees will receive voice mails in their Outlook mailboxes in the form of voice to text translation and a audio file. • Employees will be able to send and receive faxes from within Outlook. • Employees will be able join video meetings in video conference rooms from their Lync clients.	16-Dec	(1.10)	830	0	0	0	830	0	0	0

Information Technology Department

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
7	2017	ARP - Printer Asset Management (PAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy printers, plotters, and multi-function printing devices on a five-year refresh cycle for every department in the company. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older printers to complete their job tasks.	Employees require these printers/plotter to support their business efforts in support of our customers. Refreshing the equipment provides these benefits: - Reduces equipment failures reducing downtime for CE employee and meeting our customer expectation - Ensures printers can provide expected functionality with our print application meeting our customer expectations - Refreshed hardware allows Workstation software to function as designed reducing employee downtime and meeting customer expectation Customers are assured that our Call Centers and Dispatch centers have the required printing capabilities to meet our customer expectations	17-Dec	(1.05)	358,746	0	322,733	22,809	1,575	0	11,630	0
8	2017	ARP - Server	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	IT server infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT Infrastructure. This Server Asset Refresh Project (ARP) project will evaluate Computer Hardware with more than 5 years of continuous use and replace where appropriate.	The project will intelligently and systematically replace critical infrastructure before a system failure that would disrupt business operations. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers	17-Dec	(1.04)	1,090,964	160,720	548,866	81,253	258,550	0	41,576	0
9	2017	ARP - Storage	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	IT storage infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT infrastructure. This storage Asset Refresh Project (ARP) project will evaluate storage hardware with more than 5 years of continuous use and replace where appropriate.	This project is intended to address the ongoing refresh and storage growth needs within Information Technology regarding the data storage hardware. The project replaces hardware aged more than 5 years and provides incremental storage capacity where needed. The useful life of IT storage resources in a data center is 5 years. The project proactively replaces equipment after the useful life has expired to prevent unplanned outages and technology debt as well as ensuring capacity for growth. All Company business is performed based off IT systems. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers.	17-Dec	(1.04)	2,211,837	649,545	1,405,516	15,563	75,835	0	65,378	0
10	2017	ARP - Wireless Network	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is to refresh targeted portions of the Company's various wireless networks including the 800 MHz Radio System Infrastructure. Cellular telephones can be used to fill small voids but are a great hindrance to productivity as they are a 1 to 1 conversation as opposed to a one to many conversation as supported by the 800Mhz Radio System. Call setup time is greatly increased with the use of cell phones. Most radio conversations to an entire group of employees is in the 5 second range, which is often faster than the time it takes just to place a telephone call to a single employee. A prolonged outage to this system, whether caused by force majeure or human error, would impact our ability to restore services, direct crews efficiently, and has a high probability of becoming a safety issue.	The scope of this project is extending the useful life of the Company owned radio systems. It's primary focus is on the 800 MHz radio system proper but also includes other systems, sub systems and components used within the Company such as transmitters, mobiles, control equipment and to a smaller part supporting physical plant equipment - tower lighting systems, HVAC units, emergency power systems. The 800 MHz radio network that has been built and maintained by Consumers Energy is the main means of communication to our field crews.. The project provides value by insuring reliable and real time communication between company crews and dispatch locations. This benefits the customer by enhancing life safety and reducing the amount of time it takes to restore service.	17-Dec	(0.97)	1,305,702	0	1,172,360	3,244	120,011	0	10,087	0
11	2017	ARP - Workstation Asset Management (WAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy desktops and laptop computers on a four-year refresh cycle for every department in the company. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older desktops or laptops to complete their job tasks.	Benefits of the APR Workstation Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Increased system performance such as speed, battery life, etc... - Less impact on future years for capital refresh requests, just pushing the issue if we delay - Improves opportunity for CE employees to exceed expectations of our customers.	17-Dec	(1.06)	2,574,080	-412	2,437,849	99,380	-88	0	37,352	0
12	2017	ARP-Data Network	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	Network Services - Asset Refresh Data Network. In conjunction with Voice Network Team, refresh legacy Avaya data switches at the following Sites: Macomb, CCC, Trail Street, Jackson Garage, Bridge St., Kalamazoo, Flint, Ray, Zeeland Gen, Cadillac, Owosso	To replace the Avaya Nortel Switches throughout the State of Michigan	17-Dec	(1.11)	107,513	0	111,215	-2,514	0	0	-1,188	0

Information Technology Department

Line No.	(a) SPEND YEAR	(b) PROJECT NAME	(c) IT PROGRAM	(d) FERC CATEGORY	(e) UNITE CATEGORY	(f) PROJECT DESCRIPTION	(g) PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	(h) IMPLEMENT-ATION DATE	(i) COST/BENEFIT RATIO	(j) ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	(k) SOFTWARE COSTS-ELECTRIC	(l) MATERIAL COSTS-ELECTRIC	(m) LABOR COSTS-ELECTRIC	(n) CONTRACTOR COSTS-ELECTRIC	(o) ENGINEERING COSTS-ELECTRIC	(p) OVERHEAD & OTHER COSTS-ELECTRIC	(q) CONTINGENCY COSTS-ELECTRIC
13	2017	BI 4.1 Dataservices Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Deploy enterprise wide solution for sweeping and collecting forensic artifacts across the enterprise environment for all workstations, laptops and servers.	System must be capable of the following: 1) Support Windows & Linux; 2) Sweeping the environment for indicators of compromise; 3)Support STIX/TAXII; 4) Integrate alerting to IBM QRADAR SIEM	18-Dec	(0.95)	142,091	0	0	57,060	57,465	0	27,567	0
14	2017	Data Center 2.0 - Disaster Recovery	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	This is a Program to - * Mitigate the current significant risks (location risks, capacity risks, technology risks) with the Consumers Energy IT Disaster Recovery capabilities, by Collocating to a Backup Recovery Center (BRC) at a vendor facility and by enabling Disaster Recovery (DR) capabilities at full Production capacity, for all systems per when business requirements dictate full capacity * Mitigate the risk to Project/ Development activities when a DR event is in progress (as the project/ development environments are currently needed to be commandeered in case of a disaster) * Provide an environment suitable to perform expanded DR testing * Build a 100% Production capacity for DR purposes at Switch. At the end of the migration to Switch, the compute capacity at Switch will be >= the compute capacity at Parnall. Some of the capacity will be on newly purchased hardware and some will be on hardware shifted from the Battle Creek Data Center. Currently, there are no plans to put compute for Production DR in the Cloud.	Mitigate risks to the Corporation in the event of a Disaster, by significantly enhancing the Disaster recovery capabilities, DR testing capabilities, and scalability constraints at the current data center locations. Scope includes - 1) Both IT & OT Data Centers 2) Migrate BRC to a vendor Colocation data center 3) Expand DR systems capacity to support 100% Production load requirements 4) Expand DR capabilities to all applications that are determined by the business partners as needing DR Scope excludes: 1) Relocating Parnall Data Center to a Colocation facility	20-Dec	(0.82)	75,212	0	0	6,309	63,722	0	5,181	0
15	2017	ESB Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	The Enterprise Service Bus (ESB) is an Enterprise Integration Platform initially implemented to support the Advanced Metering Infrastructure (AMI) Smart Energy Applications. It enables secure flow of data from Smart Meter head ends to SAP and other systems that process and store the data.	Project scope is the upgrade all components of the enterprise service bus, and refresh underlying infrastructure as needed. This project will provide the users with more current versions of software to better meet business requirements. Additionally the project will resolve all current issues with application versions and infrastructure thereby saving expenditure on maintenance extensions and remediating risk due to unsupported technologies running in production.	20-Dec	(0.91)	2,912,476	0	2,438	880,519	1,492,700	0	536,819	0
16	2017	Lotus Notes Application Migration & Retirement Wave 3	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Lotus Notes is an unsupported technology now at CE. Most of the 600+ LN applications can be moved to SharePoint, either from a direct move or customization. The applications are categorized into simple, medium, and complex. The migration is happening in 5 Phases or Waves and this is Wave 3.	This next phase will further enable capabilities on our current collaboration platform standard (SharePoint), while reducing the risk footprint of using an unsupported standard (Lotus Notes). SharePoint gives many new enhancements to these applications including collaboration, versioning of documents, security, and automated auditing. With the use of the K2 the users can also modify their own sites once migrated to better tailor them to their business needs.	18-Apr	(1.00)	2,376,776	30,311	0	257,698	1,827,771	0	260,995	0
17	2017	Lotus Notes Application Migration Retirement	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Lotus Notes is an unsupported technology now at CE. Most of the 600+ LN applications can be moved to SharePoint, either from a direct move or customization. The applications are categorized into simple, medium, and complex. The migration is happening in 5 Phases or Waves.	This next phase will further enable capabilities on our current collaboration platform standard (SharePoint), while reducing the risk footprint of using an unsupported standard (Lotus Notes). SharePoint gives many new enhancements to these applications including collaboration, versioning of documents, security, and automated auditing. With the use of the K2 the users can also modify their own sites once migrated to better tailor them to their business needs.	17-Dec	(0.93)	-76,119	0	0	0	-76,119	0	0	0
18	2017	OWCE Nitrogen Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Compliance & Risk Management	This project will Upgrade the OpenWay Collection Engine (OWCE) to the latest version. This upgrade will be done in parallel with the hardware asset refresh to reduce overall risk and cost.	OWCE is the head end software that communicates to smart meters. The upgrade to the Nitrogen version ensures that the Company sustains this critical business function on a current and supported version.	18-Oct	(0.98)	353,958	0	256,288	23,279	59,267	0	15,124	0
19	2017	SAP Platform Modernization	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The SAP Platform Modernization Program includes the re-architecture and replacement of the 2007-2008 SAP infrastructure, which is well beyond its recommended useful life. The program also includes an upgrade of SAP applications to Enhancement Pack 8.	This program is essential for the company to maintain support and stability of its core set of business applications, while also improving system availability, performance and resiliency.	17-Sep	(1.00)	13,027,107	-564,340	919,965	1,459,326	10,235,212	0	976,944	0

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20	2017	Testing Center of Excellence (TCOE) HP Application Lifecycle Mgmt (ALM) Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	HP ALM (formerly HPQC) is our primary testing tool. It holds our test case repository enabling reuse of test cases across various initiatives. It contains test evidence, storing test execution results. It is used for test status reporting. This project upgrades HP ALM to the current version to ensure we stay on a supported version.	The intent of this project is to mitigate the risk of technology obsolescence; not being at a level of software supported by the vendor.	16-Dec	(1.01)	255	0	0	184	0	0	71	0
21	2017	Treasury Work Management	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	This project is to determine and implement a Treasury solution for cash forecasting, bank account fee analysis, and treasury work management. The remaining phases of this project will be to 1) Develop cash forecasting process; 2) Automate bank fee reconciliation process; 3) Identify bank account management tool (i.e. bank account management including signatories, etc.); and 4) Other enhancement to the solution as needed. The overall goal of the project is to significant improve Treasury work management: - Automate the cash forecasting reporting process, which is used to manage the companies daily cash position into an automated and longer forecast; - Automate the bank fee reconciliation process, which is the current highest cost in Treasury behind salaries, which may result in identification of fee reduction; and - Identify a work management tool to keep track of all of the bank accounts, their signatories, and other tasks.	The scope includes: - Replace and automate Cash Forecasting process that is currently supported by an Access database that is unsupported and subject to maintenance risks. - Replace and automate the current manual process over bank account fees. The current process is a manual process to compare bank statements to confirm that the bank service fees are correct. There are hundreds of bank service fees daily. The project impacts address: Obsolete Technology - Current technology is obsolete and breaks every time there is an upgrade or service pack to SAP and the business support personnel is no longer available to maintain the Access database. T Financial Impact: Swings in Consumers Energy's daily liquidity/Cash Position can move as much as $200 million per day (dependent on large transactions such as dividend payments, debt retirements, debt issuances, etc.). Daily changes in Liquidity/Cash Position can typically be as much as $50 million.	17-Oct	(0.92)	172,430	0	0	54,837	89,314	0	28,279	0
22	2017	Tumbleweed Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Upgraded system with support, redundancy, disaster recovery, a new test environment and additional capacity to comply with corporate operational standards to support critical business functions.	1. Upgrade Application from 5.1 to version 5.3.6 2. Create redundancy in Prod and Non Prod environments 3. Disaster Recovery 4. Increased Capacity 5. Training 6. Support Plan 7. Interfaces to other internal systems	18-Sep	(1.06)	344,581	0	232,885	34,859	61,651	0	15,186	0
23	2017	Windows 10 Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Upgrade corporate workstations from Windows 7 to the latest operating system.	The scope of the project to update the corporate workstations to the latest operating system. These upgrades are required to keep the workstation maintained, operating properly, and supported by Microsoft.	20-Dec	(0.95)	8,896	0	8,896	0	0	0	0	0
24	**SUBTOTAL**	**2017 Upgrades & Replacements (Enterprise)**								**29,529,878**	**306,650**	**9,517,728**	**3,137,162**	**14,460,377**	**0**	**2,107,961**	**0**
25	2017	DCO Portfolio Application Currency	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	DCO Current Application supports application upgrades for the following applications: Cascade, TrackStar, CYME (Electric load distribution analysis), Synergi, Uptime, FlowCal, Mains Replacement Prioritization (MRP), Maxload, ArcGIS, and others.	Upgrades for DCO applications: Cascade, Trackstar, CYME, SynerGEE, Uptime, FlowCal, MRP, Maxload, SIMS, ArcGIS & FME	22-Dec	(0.84)	761	0	5,014	13,235	1,152	0	-18,641	0
26	2017	ED - Cyme Upgrade	Upgrades & Replacements (Business Partner)	Software (Intangible)	Electric T&D, Gas T&D, Generation	The CYME Distribution Analysis software is designed for planning studies and simulating the behavior of electrical distribution networks under different operating conditions and scenarios. It includes several built-in functions that are required for distribution network planning, operation and analysis. The Cyme solution currently runs on an unsupported version of software. The vendor has encouraged Consumers to upgrade, stating that they will not be able to support future problem resolution efforts. The software is currently loaded on individual workstations. Gateway will continue to reside on server. However, a network based solution to replace the PC based solution is not a feasible solution from Cyme. The scope of this project is to "replace in kind." Once upgraded, there will be the ability to evaluate other Cyme modules for their potential value for other departments.	The CYMDIST Distribution Analysis software is a suite of applications composed of a network editor, analysis modules and user-customizable model libraries. The program is designed for planning studies and simulating the behavior of electrical distribution networks under different operating conditions and scenarios. It includes several built-in functions that are required for distribution network planning, operation and analysis. This will also require an upgrade to Cyme Gateway (this will not require hardware /infrastructure changes. Consumers must utilize Cyme, or some other solution, in order to effectively perform load flow analysis that is critical to distribution planning, outage resolution. It's used on a daily basis for switching analysis. If the software and platform are not upgraded, the vendor will not support future problem resolution, putting the ability to perform required analysis at risk.	18-Jun	(0.95)	346,546	133,669	0	138,561	36,220	0	38,097	0

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27	2017	GIS-Integrated Design	Upgrades & Replacements (Business Partner)	Software (Intangible)	Work Management	This project is to replace the current CAD/Work Requirements and Design software with a GIS based design tool for improved capabilities in the preparation of graphical designs for the order fulfillment processes for gas and electric work orders.	New functionality in scope: Ability to directly integrate with multiple ESRI databases, read data and attribution form dataset to begin design, Send data to proper data set (ESRI), electric and gas design simplification tools (streamline the actual placement of materials and attribution into a design), consumer GIS data as a service in addition to directly connect data (Replace WRaD Robosync), creating synergy for new construction of being able to send an updated design file with the corresponding updates and attribution to the GIS improving the as-built (redlining) posting process.	18-May	(0.95)	2,292,707	1,099,247	0	259,441	701,075	0	232,944	0
28	2017	ITCP – Cold Water Service Center	Upgrades & Replacements (Business Partner)	Network	Administrative & General (A&G) Support	IT will be supporting the Facilities project to build a new service center in Coldwater. This work will require new connectivity to the site, security, data, video, voice as well as SAP changes.	Included in the build of Coldwater is closing Bronson Service Center and consolidating employees in Coldwater.	18-Jul	(1.00)	63,344	0	0	14,293	42,760	0	6,292	0
29	2017	ITCP - JGR Leadership Center	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	This will be a new facility in the Grand Rapids Area.	Provide technology needed for new facilities	17-Mar	(1.05)	300,722	0	228,778	15,873	47,670	0	8,402	0
30	2017	ITCP - Parnall East Renovation	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	The high level scope for this project includes updating the major building systems of the Parnall East "C " section area and optimizing the existing space, while maintaining the company required standards and the NERC/CIP requirements of the area/building. This project is broken down into 3 phases: Phase 1 - Complete 2016 Phase 2 - Complete 2017-2018 Phase 3 - Complete 2017-2018	1. Provide all network connectivity needed at the newly renovated location to enable employees to connect with the company and SCADA networks and communicate as necessary (i.e., so employees can use the building). 2. Provide all network connectivity needed in different areas throughout Parnall for those employees who will be in temporary areas during the renovation phase of the building. 3. Support removal of network equipment at end of renovation 4. Re-cable and redirect cabling in Section "C" at Parnall East to go to the Basement MDF 5. Install new and existing AV equipment	18-Oct	(1.01)	9,363	0	0	1,120	7,521	0	722	0
31	2017	LandWorks Property Management System Upgrade V5.5	Upgrades & Replacements (Business Partner)	Software (Intangible)	Asset Management	This project is to upgrade the Land Property Management System (LMP by LandWorks) to the next version, as well upgrade to ArcGIS in order to support the version upgrade.	Application is currently on an older version and at risk of no longer being supported by vendor.	18-Oct	(0.90)	29,589	0	0	16,910	7,746	0	4,933	0
32	2017	Operations (Energy Resource) Portfolio Application Currency	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	This effort is needed to ensure application currency for the Operations (Gas, Electric & Generation) Application Portfolio. The application upgrades have been prioritized based on business criticality and value, and this project will perform the routine upgrades/maintenance to ensure IT solutions supporting Operations business processes to deliver energy to our customers are stable and current.	The Operations Application Portfolio went through an assessment to evaluate application currency and technology obsolescence for this portfolio, prioritized needed upgrades based on business criticality and value, and this project was initiated to address priorities to ensure appropriate support and performance.	19-Dec	(0.94)	53,920	0	0	23,504	19,925	0	10,490	0
33	**SUBTOTAL**	**2017 Upgrades & Replacements (Business Partner)**								**3,096,952**	**1,232,916**	**233,792**	**482,936**	**864,068**	**0**	**283,239**	**0**
34	2017	AccessNOW	Security	Software (Intangible)	Administrative & General (A&G) Support	Implementation of configurable Identity and Access Management for systems and best practices with enforced compliance. (Formerly Dell 1 Identity Manager)	This includes enterprise level foundation architecture, technology and end-2-end processes and controls. Processes will be fully automated user self-service and access lifecycle management. The project will deliver integrated and synced enterprise authoritative data.	20-Sep	(0.92)	427,185	0	4,665	149,942	198,453	0	74,125	0
35	2017	ARP - Cyber Security	Security	Network	Compliance & Risk Management	The objective for Cyber Security Asset Refresh project is to ensure continued vendor support of security technology deployed at the Company as well as reduce the risk of unplanned outages due to outdated hardware/software and appliances.	Replace end of life and obsolete systems; leading to less probability of equipment failures, software compatibility issues and business partner downtime.	17-Dec	(1.09)	887,446	24,905	647,709	27,800	176,201	0	10,831	0
36	2017	Corporate Security	Security	Network	Compliance & Risk Management	This project is actually a set of Corporate Security initiatives, which aim to implement security assets at company sites for a variety of reasons; One leading factor is the company's responsibility to stay in compliance with Federal Energy Regulatory Commission requirements.	Scope includes enhancement and/or replacement of physical security assets, as part of the lifecycle replacement program. This includes security cameras, motion detectors, intrusion detection systems and card access systems. The Company had several thousand cameras and card readers in use.	18-Dec	(1.07)	821,047	0	99,854	9,681	708,730	0	2,781	0

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37	2017	Firewall Management Platform	Security	Software (Intangible)	Compliance & Risk Management	The project will implement a firewall management platform.	Cyber security now manages nearly 100 firewalls and keeping configurations up to date, changes processed correctly and mistakes to a minimum is challenging. A firewall management platform will enable automation and workflow to provide greater security and efficiency for our team. Firewall security mistakes and failures are leading causes of data breaches.	17-Jun	(0.98)	444,921	256,796	84,463	44,745	17,423	0	41,493	0
38	2017	Mass Notification	Security	Software (Intangible)	Compliance & Risk Management	Provides the capability to communicate with desktop servers (send an alert out to desktops); and to activate a "Blue Light" at the service centers during an event (active shooter/lockdown, etc....) via the MNS system;	Implement/upgrade Siemens Fire-Panels at company locations. Similar to current capabilities used to announce "fire" events, the mass notification tool will allow notifications for other events requiring notification to building participants. This is directly tied to employee safety. Safety is increased by allowing better communications to employees during emergency situations.	18-Dec	(1.06)	9,231	0	0	23	8,500	0	708	0
39	2017	NERC/CIP Version 5	Security	New Computers / Hardware	Compliance & Risk Management	Regulations required Consumers Energy to be compliant with NERC Critical Infrastructure Protection (CIP) standards. This project is chartered to bring critical infrastructure into compliance with NERC/CIP standards.	Key project scope includes completing requirements to meet NERC CIP requirements (Version 5), which include: Identify and classify BES Cyber Assets and develop preventive, detective, and corrective controls as they apply to the NERC CIP Version 5 Standards.	18-Sep	(0.96)	928,675	42,098	362,683	96,819	279,404	0	147,672	0
40	2017	OT Security Architecture	Security	Network	Compliance & Risk Management	IT Information Security is taking responsibility for Cyber Security within various areas of the businesses' Operations Technology. The project will be used to implement a consistent security architecture across the Operational Technology landscape.	Key scope includes the continuation of implementing the Consumers Energy OT security standard across the Generation fleet.	19-Nov	(0.97)	346,113	45,438	112,711	137,044	884	0	50,037	0
41	2017	SAP IDM Integration	Security	Software (Intangible)	Compliance & Risk Management	The project will configure the Human Capital Management (HCM) component of SAP's Identity Manager (IDM) User Access Provisioning tool to connect to the HCM modules of our applicable SAP environments, for more automated system access provisioning.	The project will automate access provisioning and de-provisioning to users in SAP via HR processes including onboarding, transfers, and termination. The workflows would be configured to execute based on HR actions. The configurations enable a business role model. A business role model is access based on job functions. When business roles are developed for applicable business units, the workflows and HR configurations will allow access to be automatically assigned to users when on boarded or transferred. This will eliminate manual intervention by security personnel as well as reduce the number of access requests from end users.	17-Aug	(0.71)	319,287	0	0	27,665	281,375	0	10,247	0
42	2017	SAP Security	Security	Software (Intangible)	Compliance & Risk Management	The purpose of this project is to provide vulnerability scanning of SAP specific platforms. The project will include requirements gathering, vendor selection, product selection, tool design, configuration, and implementation. The benefit of this Project closes a gap as current information security vulnerability scanning tools do not provide the capabilities needed for new systems and solutions in our environment.	The benefit of this Project closes a gap as current information security vulnerability scanning tools do not provide the capabilities needed for new systems and solutions in our environment.	17-Aug	(0.96)	622,215	0	0	136,933	342,027	0	143,256	0
43	**SUBTOTAL**	**2017 Security**								**4,806,120**	**369,237**	**1,312,085**	**630,652**	**2,012,996**	**0**	**481,150**	**0**
44	2017	800MHz Tower Connectivity Optimization	IT Service Delivery	Network	Administrative & General (A&G) Support	Telecommunication providers have announced the discontinuation of leased TDM (Time Division Multiplexing) services (i.e. T1's) by 2020. All radio tower sites will need to migrate to alternate technologies before this date.	Maximize radio system availability to improve reliability, employee/customer safety, gas leak response, and response time to customer outages. Migrate to a newer network technology before existing T1's are no longer supported.	19-Nov	(0.94)	867,602	0	412	26,613	831,736	0	8,842	0
45	2017	Internet Connectivity Redesign	IT Service Delivery	Network	Administrative & General (A&G) Support	This project is to plan and implement an updated Internet Connectivity Architecture for the Company. The current Internet Connectivity Architecture is over 10 years old and has some deficiencies that puts the Company at risk for an interruption in Internet Connectivity that would disrupt both internal Internet Connectivity and the Company's external Internet presence (i.e. consumersenergy.com, e-mail, etc.).	This project will end the current "carrier lock" situation and make use of company owned IP address space as opposed to carrier owned address space. This project will also provide what is known as "Carrier Diversity", which will protect the company from losing Internet presence in the event of an upstream failure.	17-Jul	(1.10)	81,097	0	80	56,918	0	0	24,099	0

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46	2017	ISIS Upgrade	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	The project will upgrade the ISIS (vendor) Software used by the Company to format and print customer bills.	The ISIS Software upgrade will allow the Company to remain on a current and supported version of critical software, and sustain customer bill format and print operations.	17-Nov	(0.92)	3,246	0	1,022	1,575	0	0	649	0
47	2017	Nimbus Phase 2	IT Service Delivery	New Computers / Hardware	Administrative & General (A&G) Support	In 2015, Consumers Energy implemented its private cloud. 2015's effort was focused around creating self-service and automated deployment for basic datacenter requests. In 2016 continued expanding the features of Consumers Energy's private cloud in phase 2 project. These additional features would include: • Self-Healing: Automated repairs to server and application errors. Instead of requiring manual intervention from an operation team when a problem ticket is created, the Private cloud with automatically resolve the issues and inform CE teams that the issue was resolved. • Server Application Packaging and Self Service Deployment allowing application teams to deploy and redeploy entire environments in a matter of minutes instead of weeks. • Storage/Network virtualization allowing the private cloud to provision storage/networks when needed without requiring manual intervention and labor.	*Continue to reduce CE Build labor (Benchmarks), speed to market for IT Infrastructure services. *Develop reactive healing countermeasures to reduce infrastructure/application unplanned outages. * Develop automatic benchmarking interfaces and reports. With successful implementation of this phase of the project effort, simple errors which cause critical systems outages will be resolved before outages occur. Critical business applications will increase in size before our customers and our business feels performance issues.	17-Dec	(1.03)	-1,699	0	0	-1,104	0	0	-595	0
48	2017	Printer Document Management Platform	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	This Project will implement control over our costs in CE's print environment. By moving to a document platform, CE will be able to save time and money by streamlining internal processes, reducing our risk, increase our productivity and efficiencies as well as creating value within the ITAM department	Today, since scanning and faxing are available without authenticating to everyone, it is not possible to audit these activities and determine exactly who might be scanning or faxing and what they might be sending. This is a significant risk to CE as information can be sent out of the organization today , without specifically being able to track who is sending it. The authentication function in the Managed Document Platform will eliminate this risk and increase CE's security. Sarbanes - Oxley Act and HIPPA Compliant (HR Department)	17-Jul	(1.01)	779,127	399,337	-382,945	127,630	535,329	0	99,776	0
49	2017	SAP Archiving	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	With SAP being the company's primary Enterprise Resource Planning (ERP) platform for the integration of business processes, the daily system usage has resulted in massive amounts of data to be stored in SAP. Currently the size of the SAP ECC database alone is 23TB and is growing.	(1) Meet compliance requirements by purging any data that can become a liability as identified by CE legal team (2) Build an Archiving solution that allows the business to retrieve archived data with ease and in the form that is needed	17-Dec	(0.93)	346,674	0	0	34,678	266,037	0	45,959	0
50	2017	SAP Performance Tuning	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	The project aims to target two major work streams to help improve SAP Performance (1) Use Oracle compression on large tables to decelerate the data growth in ECC and improve performance (2) Analyze Custom Code that can be retired or remediated to improve performance	(1) Perform Custom Code Analysis to identify code to retire and remediate (2) Identify the top 30 tables in ECC for compression. (3) Identify SAP data purge targets and purge data to improve performance	16-Dec	(0.97)	550	0	0	0	0	0	550	0
51	2017	Service Now Phase III	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	ServiceNow Phase 3 will implement four applications, Asset Discovery, Service mapping, Purchasing Automation, Knowledge Base and Event Manager. ServiceNow Phase III will introduce functionality not currently available to CE. Asset Discovery, Service Mapping, and Event Manager will provide the capability to track, classify, and manage technical relationships of install software and hardware configurations in an automated method. Purchase Automation will allow the creation and management of purchase orders related to service catalog requests. Knowledge Base will new functionality to manage information.	Asset Discovery and Service Mapping: ServiceNow Asset Discovery & Service Mapping provide new and enhanced functionality to better manage our hardware and software assets • Software discovery will be used to help normalize the hardware owned, thereby reducing costs • Ability to discover all hardware on the Consumers Energy's network • Manages the relationships between services by mapping a service to the configuration item. A business services management map displays the CIs that support a business service and the relationships that between the CIs involved in that service • Service Mapping scans the network for changes that have been completed without the proper change management processes conducted. Will reduce the amount of undocumented changes that put our network at risk.	17-Mar	(1.00)	-7,060	-11,622	0	311	4,132	0	119	0

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Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
52	2017	SNOW License Manager (LM)	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	This project will support asset management and asset integrity to drive down licensing costs. This project will implement the SNOW (product name) Licensing Manager Software and associated SNOW tools and the required servers as well as perform the initial compilation and reconciliation of licensing data for SuSE, Adobe, HP, MS, and VMware and the reconciliation and Optimization for SAP and Oracle. This project will give CE the ability to monitor and manage software asset usage, license distribution, and assess optimization possibilities so that CE can lower risk/cost of non-compliance, lower support costs and support IT efforts to identify licenses available for harvest, redistribution and release.	Uncover savings related SW (software) Licensing through process improvement and support for strategic decision making • Implement SNOW SW technology to ensure identification and accurate monitoring of all IT SW assets • Reduce non-compliance findings and associated costs • Enforce compliance of all software assets including: licenses and entitlements The SNOW licensing manager will give CE the ability to monitor, manage, assess and identify all software applications. This will decrease the time required to support a vendor's compliance audit, identify non-compliances so that they can be resolved and identify opportunities to harvest and redistribute SW as well as identify opportunities to release licenses. It will also allow us the ability to support enforce corporate compliance requirements for all software assets including licenses and entitlements.	17-Mar	5.00	158,712	11,557	0	1,335	134,609	0	11,211	0
53	2017	TCoE Automated Testing 2017 - SAP Regression	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	This project will automate test scenarios that are frequently used in SAP regression tests to ensure that changes being introduced, such as SAP support packs or SAP enhancements, do not adversely impact functionality.	The value of automated testing is reduced regression testing time and effort, which leads to better quality service to our customers and employees.	17-Dec	1.11	147,100	0	2,867	45,103	72,382	0	26,748	0
54	**SUBTOTAL**	**2017 IT Service Delivery**								**2,375,348**	**399,272**	**-378,565**	**293,058**	**1,844,224**	**0**	**217,358**	**0**
55	2017	Enhancements - Corp-Shared Svcs	Enhancements	Software (Intangible)	Administrative & General (A&G) Support	Small software enhancement work efforts performed for Corporate and Shared Services business areas.	Each enhancement request has defined business value.	17-Dec	(0.96)	506,381	0	0	208,622	205,985	0	91,773	0
56	2017	Enhancements - CX-DCO	Enhancements	Software (Intangible)	Customer Management	Small software enhancement work efforts performed for Customer Experience business areas.	Each enhancement request has defined business value.	17-Dec	(0.98)	1,121,006	97,662	0	299,390	568,773	0	155,180	0
57	2017	Enhancements - DCO	Enhancements	Software (Intangible)	Customer Management	Small software enhancement work efforts performed for the Distribution Operations business area.	Each enhancement request has defined business value.	17-Dec	(0.96)	523,267	0	-898	155,968	270,414	0	97,782	0
58	2017	Enhancements - Energy Resources	Enhancements	Software (Intangible)	Electric T&D, Gas T&D, Generation	Small software enhancement work efforts performed for the Energy Resources business area.	Each enhancement request has defined business value. 2017 & 2018 Requests Include: FERC Market Based Rate Filings GCC – Mass move for Suppliers SAP Catalog 'B' Addition Request SAP Functional Data Fields - System Owner Met/Team customer portal external facing GIS Web Portal Layer DLA – Solution to SAP Alerts (DLA) GCC - Customers able to Block GCC enrollments Re-provisioning of non-communicating switches in batch/bulk in DRMS for DLA Gas C&S work management	22-Dec	(0.94)	74,546	0	0	6,321	64,094	0	4,132	0
59	**SUBTOTAL**	**2017 Enhancements**								**2,225,199**	**97,662**	**-898**	**670,302**	**1,109,266**	**0**	**348,867**	**0**
60	2017	5 Minute Settlements	BP Functionality	Software (Intangible)	Energy Portfolio Planning	PCI Back Office Suite, PCI Profit and Loss Analyzer, PCI Settlement Analyzer, PCI Energy Accounting, EA Data Mart, and GenTrader require a major redesign and upgrade to support the new MISO 5-Minute Settlements solution (Requirement of FERC Order 825). Moving to 5 minute intervals for data will result in a significant increase in database size, requiring new hardware/OS for database servers.	In order to continue settlements with MISO, and to meet requirements of FERC Order 825, this upgrade is required by April 1, 2018. Not completing this work would have negative financial and compliance implications.	18-Oct	(0.95)	54,955	12,981	41,974	0	0	0	0	0
61	2017	Account Reconciliation	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	This project is to replace the existing Lotus Notes application used to perform account reconciliation of General Ledger accounts on a monthly basis. This application will include ability to attach supporting documentation, electronic routing and approval	Account Reconciliation Process is a Lotus Notes application that is no longer supported. This project is move this application to another solution providing similar functionality and workflow functionality which will improve work processes.	17-May	(0.94)	52,309	0	0	28,941	10,563	0	12,806	0
62	2017	API Management	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	API (Application Programming Interface) management refers to the ability to design, publish and deploy APIs. Advanced capabilities include API virtualization. This set of capabilities are implemented using an API catalog where APIs are designed and published during build, and API gateways w	Goals: 1) Reduce project schedule and costs by providing business analysts, developers and testers tools and processes to quickly understand data and functional integration between IT systems and gain a common understanding 2) Implement security and operational reliability of APIs and the back end systems	18-Feb	(0.95)	70,211	0	0	44,754	10,157	0	15,301	0

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63	2017	BPC Automation and Reporting	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	BusinessObjects Planning Consolidation project provides version upgrade that allows for functionality for automation of data loading and reporting. New functionality for data ad hoc analysis for gas/electric price volume and general ledger validations.	Provide version upgrade that allows for functionality for automation of data loading and reporting.	18-Apr	(1.02)	73,781	0	0	10,023	57,819	0	5,939	0
64	2017	Business Continuity Disaster Recovery Integration	BP Functionality	Software (Intangible)	Compliance & Risk Management	Implement technology solution and supporting processes to integrate the Company's business continuity and disaster recovery programs to enhance program efficiency and effectiveness.	Solution will improve program management and drive efficiency with the following: o Plan management repository with workflow capabilities (in support of plan development/review, training and testing requirements o Maintain program schedules, monitor status and reporting capabilities o Risk analysis and interdependency mapping of critical business processes and IT applications o Flagging mechanism to ensure identification of restoration capability gaps to critical business processes and/or IT recovery capabilities o Business Impact Analysis (BIA) capabilities to quantify financial risks to critical process disruptions	18-May	(0.74)	135,710	0	108,601	20,998	0	0	6,111	0
65	2017	CE Website Replacement	BP Functionality	Software (Intangible)	Customer Management	Redesign the CE Energy website to make the navigation, style, appearance and features current. The site will be more user friendly to visitors. By enabling customer mobility, Consumers Energy's customers can access functionality on our website in a view optimized for their mobile device. Features can include: - Increased Customer focus through content modification, which will increase web usage and longevity, and decrease call center contacts by making the website a user-friendly, value-add interface - Improved appearance, navigation and features.	Increase our customer's overall satisfaction and interaction with the Company. Increased customer focus through content modification and tagging to increase web usage and decrease call center contacts by making the website a user-friendly, value-add interface - Improved appearance, navigation, search and features - More customer-focused presentation of safety, regulatory and other required information in order to increase adherence - Content migration (some content will be migrated, rewritten, enhanced, or deleted)	15-Sep	(0.63)	-17,833	0	0	-11,592	0	0	-6,242	0
66	2017	Contact Center Customer Experience Refresh	BP Functionality	Network	Customer Management	Comprehensive refresh of the Customer Call Center's IT infrastructure, including the three Automatic Call Distributor (ACD) systems, networking equipment , IVRs, Work Force Management, servers, and applications. The ACD Systems are 10 years old in 2015 and cannot readily adapt to best practice. Additionally, they are no longer vendor supported and hardware replacement parts are not available.	Speech enabled interactive voice response (IVR) Customer Service Representative Knowledge Management email Management Call Center Quality Monitoring Optimize Skills Based routing Customer Analytics Enhancements Multi-Channel Inbound & Outbound Communications Virtual Hold Click to Call	18-Apr	(0.55)	4,054,554	425,702	23,929	624,300	1,946,358	0	1,034,265	0
67	2017	Corporate Capital	BP Functionality	New Computers / Hardware	Administrative & General (A&G) Support	The capital is used to fund expenditures for senior officers, corporate officers, and corporate departments. In the past capital has been focused in the areas of IT equipment and related peripherals, video equipment for the Communications team, and facilities (furniture and officer/director moves). Small corporate expenditures that meet the spending threshold for capital, but not projects - No business case document	To meet the emergent, IT, and facility needs of the corporate area, and support the overall utility. Hardware nearing the end of lifecycle. Officers and new employees will be using new equipment to access their work to maximize productivity. Meeting the emergent IT needs of the corporate area ensures continuity of business processes. The facility office moves will increase the productivity of teams by grouping them together following a re-organization.	17-Dec	-	947,054	0	947,054	0	0	0	0	0
68	2017	Credit and Collections	BP Functionality	Software (Intangible)	Customer Management	Investigate ways to leverage IT applications to support the lowering of uncollectible expense goals. Payments are uploaded and credit to a customers account automatically and efficiently. Examples are : SaaS (DebtNext) This would be to manage campaigns/channels etc. across the entire portfolio of Active, Final and Written-off. Technology Benefits: DebtNext - Cloud computing vs IT resources, customize system to meet business needs People Benefits - DebtNext - Real time decision support with reporting options provided Enhanced Communications - Easily understand, new communication channels (i.e. postcards) Process Benefits - DebtNext - would manage third party collections vendors and accounts placed with them. What we "need to do" not "what we have done" Financial Benefits - DebtNext - Reduce Cost and improve operations.	Technology Benefits: DebtNext - Cloud computing vs IT resources, customize system to meet business needs People Benefits - DebtNext - Real time decision support with reporting options provided Enhanced Communications - Easily understand, new communication channels (i.e. postcards) Process Benefits - DebtNext - would manage third party collections vendors and accounts placed with them. What we "need to do" not "what we have done" Financial Benefits - DebtNext - Reduce Cost and improve operations. Audit trail. / Reduce collectibles; Better visibly on age of inventory; Ability to move accounts	19-Nov	5.00	1,387	0	0	87	1,204	0	96	0

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69	2017	Customer Care Excellence (Interactions -SIP Based Implementation) (IVR Solutions)	BP Functionality	Software (Intangible)	Customer Management	Interactions Virtual Assistant solutions turn frustrating experiences into productive conversations. The application will that deliver unprecedented comprehension, so customers can speak in their own words.	Create a path for exceptional customer service through a natural language system. Achieve operational efficiency by reducing agent call time. Provide automated solution to solve the start, stop and transfer service. Improved reporting capabilities to enable management of the self service channel. Increase customer satisfaction and contact center efficiency.	17-May	0.77	410,952	0	-1,361	91,676	261,913	0	58,724	0
70	2017	DCE Website Replacement R2	BP Functionality	Software (Intangible)	Customer Management	The DCE (Digital Customer Experience) Website Replacement R2 project is expected to provide significant new capabilities for payment transactions that our customers expect to see from all of their service providers.	The new payment interface will introduce more payment options, provide consistency of those options across all payment channels, and allow all but the Company's largest industrial customers to pay by any method. Features include allowing customers to see their balance change immediately upon making a payment, make one-time credit card payments online, pay a higher amount than is due, change their payment date to the day the bill is due (for customers on Auto-Pay), process a credit card payment by simply replying "YES" when they receive a text that their bill is ready to be viewed, make a payment on another customer's account, make a payment without logging into the Company's website, and allow phone agents to take payments	18-Jun	(1.01)	-231,355	-21,642	9,202	62,859	-346,357	0	64,582	0
71	2017	DCE Website Replacement_R3A 2017	BP Functionality	Software (Intangible)	Customer Management	This project release will implement Website search functionality	• Integrated search provides users the option of using search as a primary navigation source or for assistance in locating content of interest. Statistics vary on the percentage of customers who prefer search over traditional navigation. • Inability to find desired content is the top reason customers report having to call after first attempting to self-serve on the website • Search provides valuable diagnostics/analytics on what customers are looking for, which helps prioritize initiatives and optimize site content	17-Jul	(0.97)	1,256,793	181,214	0	180,628	769,844	0	125,106	0
72	2017	DCE Website Replacement_R3B 2017	BP Functionality	Software (Intangible)	Customer Management	This project release will implement Sitecore Version 8.2	• Version 8.2 is a significant upgrades to the current 7.5 version. It provides: o Website analytics to help identify opportunities to improve site traffic and performance. This includes "value" assignment for advanced target marketing capabilities o Includes launch of a "forms" module that will help accelerate development of online forms that allow customers to complete transactions on the new website o Will improve website performance	18-Oct	(0.97)	942,351	0	0	89,937	732,378	0	120,036	0
73	2017	DCE Website Replacement_R3C 2017	BP Functionality	Software (Intangible)	Customer Management	This project release will implement Profile Update/Profile Wizard	• Will create a new "create profile" and "profile update" user flow that introduces customers to Consumers Energy service options and will remind customers when their profiles are incomplete. o This first version will include alerts, ebill and choose due date. o Subsequent versions will include EE/RE options and rates. Additional options are expected to be added.	18-Nov	(0.84)	1,640,608	921	0	164,781	1,273,929	0	200,978	0
74	2017	DCO Advanced Planning and Reporting	BP Functionality	Software (Intangible)	Work Management	The purpose of this project is to re-evaluate the current Project Systems WBS Hierarchy structure (primarily Blanket Orders and shadow projects) into a more efficient and effective way to report and analyze Capital and O&M work programs. The current structure, based on the original approach defined in 2006 has created a large and unyielding amount of data that prevents the ability to generate cost reports, and furthermore the current structure does not provide the ability to take full advantage of IM (Investment Management module in SAP) functionality to associate actuals, overheads and other cost allocations.	The Project will address the current structure of the SAP PR Program Hierarchy and WBS elements. By modifying them, the IT Organization will be in a position to prevent or mitigate the following situations: "the amount of data will continue to grow, reporting will be unable to handle the volume of data and "time-out"; data volume prevents the ability to access the structures for updating and modification; year-end budget assignment from SAP IM is hampered."	17-Sep	(0.10)	413,724	0	0	107,946	233,405	0	72,373	0
75	2017	EA - OMS SG User Interface	BP Functionality	Software (Intangible)	Asset Management	Retire ARIS application.	No longer pay support for ARIS>	19-Dec	(0.87)	273,678	0	0	36,339	180,448	0	56,891	0

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76	2017	ECM-ProjectWise	BP Functionality	Software (Intangible)	Asset Management	This ECM (Engineering Content Management) project is to investigate and install drawing management software capable of bundling, managing and handling the versions of Gas records/documents related to design, proposals, contract resources and record-keeping.	The solution will be capable of bundling, managing and handling the versions of documents related to design, proposals, contract resources and record-keeping. 1. It must be able to render, as one document, drawings that are composed of several files, as is the case with many CAD drawings such as those produced in Microstation and AutoCAD software. 2. It must be able to maintain spatial relationships within drawings and documents such that all documents pertinent to a geographical location can be quickly located and maintained. 3. It must be able to integrate with Microstation, Microsoft Office, AutoCAD, SharePoint, SAP and potentially other systems.	18-Mar	(0.95)	594,779	325,154	0	63,464	159,121	0	47,041	0
77	2017	ED - ARP OSI HVD and LVD SCADA Upgrades	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	The Electric Distribution (ED) Asset Refresh Project (ARP) upgrades OSII Supervisory Control and Data Acquisition (SCADA) application for High Voltage Distribution (HVD) and Low Voltage Distribution (LVD) systems. Biennial hardware refresh included.	Required to maintain the HVD and LVD electric SCADA grid.	18-Jun	(0.98)	815,273	4,329	467,931	37,644	287,986	0	17,382	0
78	2017	Field Service Solution	BP Functionality	Software (Intangible)	Work Management	The project will replace the current field work management applications, which will become unsupported and resides on obsolete infrastructure. The project will also replace field devices, and address needed improvements for field workers, schedulers, dispatchers, and field leaders to be safe, efficient, and deliver customer value.	Improvements on current applications and devices are necessary to: - Enable Field Workers with tools and processes that provide a simplified and streamlined way to view and complete work with relevant, real-time information that enhances CMS Energy's customer experience and increases safety and productivity in the field - Enable Field Leaders with the tools and processes to spend more time in the field coaching and supervising their crews - Enable Schedulers and Dispatchers with the tools and processes to efficiently distribute and route work to meet customer commitments by providing an integrated real-time view of all resources and work status - Mitigate technology obsolescence with current OMAR (Order Mgmt and Routing) architecture and solution.	16-Jul	(0.26)	-117,700	-117,754	0	0	-26	0	80	0
79	2017	Field Service Solution Release 2	BP Functionality	Software (Intangible)	Work Management	Field Service Solution (FSS) Release 2 will provide continued enhancement to address improvements for field workers, schedulers, dispatchers, and field leaders to be safe, efficient, and deliver customer value	FSS Release 2 enhancements include the following - 1. Est. Time of Restoration (ETR) -Improve the timeliness and accuracy of incident / work order level ETRs while reducing the frequency of changes to the ETR field. Improvement in the transparency of process changes made in dispatch and the field who are ultimately responsible for the ETR data point. 2. Fleet Summary - Need ability to update the fleet summary screen data dynamically when a mobile field worker goes on-route or on-site. Fleet Summary will provide Sub and circuit visibility on Dispatch Application screen as it was in OMAR	17-Jan	(0.82)	-10,365	0	0	26	-9,500	0	-891	0
80	2017	Field Service Solution Release 3	BP Functionality	Software (Intangible)	Work Management	FSS Release 3 provides continued enhancement needed for field workers and field leaders to be safe, efficient, and deliver customer value. Release 3 is targeting three implementation dates.	Release 3.1 will include improvements in the areas of: the overall order creation process, Gas Distribution and Construction work order completion, MISS DIG Service Suite work order, enhanced ties to SAP timesheet including SAP Manager Self Service, Support of data input from bar code reader technology; including changes to SAP parsing logic for the input fields, Addition of required codes to work orders, Improvements in Dispatch Application and Dispatch Schedule screens to enhance dispatcher experience, Gas Leak orders, use by the Catastrophic Crew System, Creation of new reports from automated scheduling engine Release 3.2 will include system functionality in the areas of: OMS Cancelled orders, Disconnect/ Reconnects, capturing of Lat/Long information in Service Suite and post to GIS, Appliance Service Plan (ASP) improvements, Automate sub/ckt information in emergent orders that bypass OMS, improvements for Gas Comm Module (GCM) work orders, Gas Leak work orders, and form improvements.	17-Dec	(0.67)	2,466,476	0	8,756	1,174,333	869,881	0	413,505	0

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81	2017	Financial Planning Transformation - R1 Basic Support	BP Functionality	Software (Intangible)	Investment Planning & Project Mgmt	The objective of the project is to implement a corporate wide solution for selecting all Company Projects, ensuring selection of the right projects and optimizing use of company resources in delivering the projects.	This solution will be phased and will provide the foundation for strategic portfolio management across the entire utility portfolio: 1. Long-term resource and financial planning 2. Consistent and aligned project scoring, characterization, and prioritization 3. Visibility into portfolios, programs, and individual projects from multiple vantage points 4. Standard estimation tool that feed SAP Financials 5. Interface with existing PM tools (Oracle Primavera P6, Clarity, etc.) 6. Risk estimating tool that interfaces with budget/SAP financials process	17-Aug	0.61	989,727	0	0	230,263	613,820	0	145,644	0
82	2017	GM - Distribution Management System - Release 1	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	The scope of this portion of the DMS is implementation of OSI's eMap solution. It includes integration with GIS and is a foundational component for the broader implementation of a comprehensive DMS/ADMS. The purpose of this project is to implement the first release of a Distribution Management System (DMS). OSI Modules to be implemented include: - Distribution Network Operating Model (eMap) - GIS Interface	This module will provide the foundation necessary for the broader implementation of a comprehensive DMS. A DMS system is an electric network management sol. that provides advanced functionality in distribution grid analysis, oper. and restoration	18-Nov	(0.99)	807,094	0	598,423	5,160	193,399	0	10,112	0
83	2017	GM - Electric System Model Enhancement	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	Implement an Electric Grid System Model that will support the current and future needs of GIS, OMS, DPS (CYME), DMS and GIS Integrated Design Tool. The Electric Grid System Model will be designed and implemented to serve as an extensible platform to efficiently and effectively manage and share the Electric GIS network model information with the rest of grid operational and planning systems. Establish a methodology for integration that will connect Electric GIS, SAP, Cascade and other Asset Management Systems in a common way to provide an integrated view of assets across asset management areas.	The Project will achieve the following high level objectives in support of the Grid Modernization Program: (no specific order) 1. Capture all primary and secondary pole locations within one (1) meter accuracy and reconcile the existing EGIS connectivity model to these locations to support DMS and other advanced applications. 2. Evaluate and enhance EGIS integrations with SAP and OMS to provide a more flexible support model and data accuracy in preparation for DMS by following Consumers Energy's integration standards and where applicable leverage the IEC 61968 CIM standards for integration and common networked model exchanges. 3. Consolidate disparate electric distribution GIS databases into a common shared electric GIS platform. 4. Implement change management associated with business processes for managing all electric distribution map records. 5. During execution of the project, all EGIS integrated processes will continue to operate without unplanned disruption.	18-Jul	(0.97)	673,419	18,663	0	185,575	279,994	0	189,187	0
84	2017	GM - GIS Connectivity Model Integration	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	An end to end integration to publish the GIS connectivity model from GIS to the Tibco ESB, leveraging the CIM standard. Create a service delivery point based asset framework in the MODM historian.	Interface Reference Model (IRM) for Grid Modernization Program. Touchpoints and logical interfaces have already been developed to support a DMS. Integration to TIBCO and supporting adaptors. MODM will subscribe to the ESB	19-Jan	(1.02)	428,322	29,680	0	53,410	308,837	0	36,395	0
85	2017	GM - Grid Communication Modernization	BP Functionality	Network	Electric T&D, Gas T&D, Generation	Verizon has announced that they will no longer offer their analog, multi-drop phone service as of February 28, 2015 and their Frame Relay service after December 31, 2015. These services are an integral component of the SCADA communication infrastructure.	A wired and wireless solution to replace Verizon's sunsetted services (analog multidrop circuits and frame relay circuits). Defined minimum and uptime requirements. Sufficient site coverage.	18-Dec	(0.98)	474,603	33,233	191,872	5,784	213,653	0	30,060	0
86	2017	GM - Line Sensor Initial Rollout	BP Functionality	Network	Electric T&D, Gas T&D, Generation	This IT project is to support the initial Energy Delivery line sensor roll-out as part of the Grid Modernization program. This IT portion of the broader scope includes communications design, modem configuration and purchase and installation of a head end/device management server and integration with SCADA systems (HVD and LVD) associated with the initial group (~300) of line sensing devices throughout Consumers Energy distribution system.	Installation of up to 300 line sensors(with pre-installed modems) with larger roll-out funded separately. The implementation will be prioritized based upon most unreliable feeders. IT requirements include communications design, modem configuration and purchase and installation of a head end/device management server and integration with SCADA systems (HVD and LVD). To accurately and quickly pinpoint trouble location on feeders so immediate step restoration can proceed. To leverage the 10 year DSCADA project so station information that is required can be obtained almost immediately. Communications costs will be dependent upon data volume, frequency and unsolicited/solicited capabilities of the devices.	18-Feb	(1.07)	168,525	1,641	83,556	53,937	2,569	0	26,822	0

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Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
87	2017	GM - Utility Analytics	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	This project will provide the infrastructure and framework for data analytics across Consumers Energy. This integrated platform will be leveraged to support analysis of cross functional data that will result in actionable information.	The implementation of intelligent field devices provides Consumers with an enormous amount of data. Turning that data into actionable information requires implementation of an enterprise wide framework.	18-May	(0.52)	2,052,129	71,987	1,016,460	303,936	447,432	0	212,313	0
88	2017	Hydro Network Improvement/Connectivity Upgrade	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	Provide reliable corporate network connectivity to three non-headquarter, Hydro-Electric Generation sites. Along with appropriate bandwidth necessary to deliver acceptable network performance for the Hydro Control and Monitoring System (operational technology), SAP, eSOMS, SharePoint, and other critical applications. Three Hydro/Dam Sites: Rogers Cooke Foote	The benefits of this project include: 1. Provide reliable business and operational network connectivity to the ten non-headquarter, hydro-electric generating sites. Along with the bandwidth necessary to deliver commonly acceptable network performance for the Hydro Control and Monitoring System (operational technology), SAP, eSOMs, SharePoint, and other critical applications. 2. The networks must be available and reliable as they are an integral part of the Hydro Monitoring and Control System. For example, the Rogers, Hardy, and Croton sites (along the Muskegon river) plant control systems are each interdependent on inputs from the others to control within regulatory requirements. 3. To achieve expected productivity, hydro operators must be able to use their critical applications like eSOMS, SharePoint, and SAP while physically at any of the hydro generation sites.	18-Nov	(1.06)	349,318	0	348,884	0	0	0	434	0
89	2017	Integrated Training (Dispatch Simulator)	BP Functionality	Software (Intangible)	Work Management	Business requires a dedicated training environment that integrates SAP, OMS, and Service Suite (FSS) that will be utilized by employees in DOET. The current QA Environment consists of SAP, OMS, and OMAR systems linked together which allows the user to be training on the entire process from start to finish in a more realistic setup. Duplication of the environment is a key factor on the delivery of our commitment to increase the number of trained and proficient employees working storm restoration efforts.	Business requires a dedicated training environment for each of the systems, OMS, SAP, and Service Suite (FSS) that will be integrated/communicate as setup in production. This will allow users (Dispatch employees and other employees supporting storm operation) to train on the entire process from start to finish. OMS upgrade included a dedicated training environment, SAP has an existing training environment and Service Suite (FSS) produced a dedicated Service Suite training environment as part of Release 1. This project will complete the integration between all the environments. The lack of a dedicated training environment for employees has hindered our ability to effectively run restoration efforts that provide the most effective results for our customers - i.e. CAIDI, 8-hour normal by, etc. Currently employees develop their skills through on-the-job training with no availability to have year-round training access, or to be able to practice in a simulated storm sessions.	18-Mar	3.31	128,568	0	0	22,877	89,243	0	16,448	0
90	2017	ITCP - 12th Flr Conf Rm Renovation	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	The 12th floor situation and board room are to be renovated. There will be new furniture and AV/IT requirements for the are that will bring the rooms up to newer technology and collaboration work areas.	The scope of the project is to renovate the current situation and boardroom to make it more collaborative for the executives in the company. New furniture, layout and AV will be required for the area. Most of the work will be done with outside vendors. This will assist the executives in better functionality and collaboration.	17-Dec	(1.04)	335,011	0	30,477	19,162	277,116	0	8,256	0
91	2017	ITCP - 12th Flr Conf Rm Renovation	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	The 12th floor situation and board room are to be renovated. There will be new furniture and AV/IT requirements for the are that will bring the rooms up to newer technology and collaboration work areas.	The scope of the project is to renovate the current situation and boardroom to make it more collaborative for the executives in the company. New furniture, layout and AV will be required for the area. Most of the work will be done with outside vendors. This will assist the executives in better functionality and collaboration.	17-Dec	(1.04)	-154	0	-154	0	0	0	0	0
92	2017	Service Bench for VAPS	BP Functionality	Software (Intangible)	Customer Management	Enable better operational management, customer satisfaction and set the BU up for future expansion. Improve margin for the entire program which can be utilized at the corporate level to either offset utility customers rate increases or shareholder return	ServiceBench is a third party software platform specifically designed for service companies to utilize its modular software platform for effortless scheduling and dispatch, field work management, automated claims processing and real-time updates partnered with powerful analytics. This will be the replacement of SuperCOW as a new Service Mgmt System. This software performs scheduling, dispatching, field work management, automated claims processing, and data analytics. *manage resource availability *accept, dispatch, and monitor jobs *verify warranty authorizations *connect field reps with mobile app *verification of background screening *validation of trade licenses and certification *view parts availability, expedite ordering, track shipments *claims management *capture job site phots and customer signatures *provide field techs with directions, parts availability, job details, etc. *schedule repairs based on availability, location, products serviced *ability to send text, email, phone alerts to customer	18-Nov	2.93	322,060	0	0	53,836	241,070	0	27,153	0

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93	2017	Strategic Sourcing Assessment	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	No Business Case	No Business Case		-	-25,738	0	-6,209	0	-19,528	0	0	0
94	2017	Supply Chain - Inventory Optimization	BP Functionality	Software (Intangible)	Supply Chain	Supply Chain Inventory Optimization: Improve service levels; Tool assumes a 99.7% service level for critical materials; Ability to segment inventory by criticality; Current process is manual; Improve, automate management by category segmentation; Proactive Risk Identification; Notifications when service levels will be impacted; Inactive inventory management; Proper categorization of non-moving inventory for potential write-off; Automated, standard and sustainable process; Tool calculates actual lead times and updates system; Tool updates SAP automatically once analyst reviews	This will allow for accuracy and management of inventory (especially generation materials/parts) and how much inventory is on hand.	18-Feb	(0.18)	420,979	0	264,797	9,027	142,549	0	4,606	0
95	2017	Tax Work Management Tool	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	This project is to identify and implement a tool to replace the current Tax Lotus Notes databases. There is tax work outside of tax returns, for example, investigating specific tax law application or company tax strategy. This work is an iterative process that requires an assignment tool, workflows, approvals, dashboards with status for multiple work streams. The overall goal is to provide a tool that helps the Tax Department with their work management.	The overall goal of the project is to significantly improve Tax work management: - Automate tax processes and sign off workflows; - Digitize document management and archiving of tax records; - Automate tax forecasting reporting; and - Retention of institutional knowledge - automated calculations and documented processes.	17-Oct	(0.98)	203,712	0	0	39,573	132,258	0	31,881	0
96	2017	Wholesale Contractual Settlements	BP Functionality	Software (Intangible)	Energy Portfolio Planning	Wholesale Contractual Settlements currently uses a combination of Excel and Fortran programs to produce Remittance Statements to suppliers and NUGs (Non-Utility Generators). 70 contracts in total; 8 are Fortran which are 20+ years old and are for more complex contracts (more details, variables, scenarios and to the minute reads for the bill month). These contracts manage $960M annually. Consumers Energy has more PPAs than most utilities and each of these has varying parameters. Likely a phased solution first concentrating on replacing the Fortran programs and a second phase to replace and retire the Excel contract settlements. Replace Fortran and Excel programs and process; robust analytic capability and reporting; improve remittance process; integration with Managed Meter Solution (PCI EA and DW).	Create and implement a contractual settlements solution that will leverage the PCI EA and data warehouse for MISO settlements. Evaluate best platform for contracts which are currently in Excel and Fortran. Replace Fortran and Excel programs and process; robust analytic capability and reporting; improve remittance process; integration with Managed Meter Solution (PCI EA and DW). Functionality must accommodate many parameters specific to each contract; some very complex with a large number of parameters. Initial design includes implementing the Settlements Analyzer module from PCI and working with PCI to set up infrastructure that enables in-house development of invoices. If current solution fails, inability to accurately and timely settle supplier contracts which would result in legal issues and large interest payments (prime rate plus 1% of $75M/monthly contracts) and penalties for contract default if we do not settle by contract due dates.	18-Sep	(0.70)	664,669	87,413	-44,520	213,800	311,570	0	96,405	0
97	**SUBTOTAL**	**2017 BP Functionality**								**21,819,587**	**1,053,523**	**4,089,673**	**3,923,485**	**9,673,104**	**0**	**3,079,801**	**0**
98	2017	Nimbus Phase 3	Architecture	Software (Intangible)	Administrative & General (A&G) Support	Nimbus Phase 3 will be adding additional features to Nimbus as well as integrating Nimbus with a Public cloud provider of our choice. o The ability to build servers to All CE clusters. Currently 6% (55 servers) of the servers we build require a special cluster not supported by Nimbus. Savings: 440 hours o Integration with our backup solution. This work was not done in 2015 due to lack of development environments as well as a lack of knowledge of integration from the teams that owned those systems. We will close these gaps and resolve issues we have from servers not being backed up and monitored. 271 hours. o Innovation Space: A feature will be developed to provide a set amount of resources for a period of time to any business partner to allow them to try software, without going through a long process. (Goal to improve business partner satisfaction goals.) o Initiate Public Cloud Provisioning foundation development to support the Datacenter Strategy	Due to the increasing demand from the business, IT focus on time to delivery, the Unite benchmarking, and the maturity of cloud technology, this is a continuation of the development of the infrastructure automation processes to reduce provisioning labor and decrease the time to delivery. The project scope includes analyzing infrastructure build and maintenance processes, modifying the processes as needed, developing the workflows for these build processes, and writing the scripts to automate these processes with the goal of accelerating platform provisioning and maintenance.	17-Dec	(0.34)	774,111	24,669	57,636	390,229	162,507	0	139,070	0
99	**SUBTOTAL**	**2017 Architecture**								**774,111**	**24,669**	**57,636**	**390,229**	**162,507**	**0**	**139,070**	**0**
100	**TOTAL**	**2017**								**64,627,195**	**3,483,930**	**14,831,451**	**9,527,824**	**30,126,543**	**0**	**6,657,447**	**0**

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101	2018	Application Performance Monitoring	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Implement an end to end systems performance monitoring solution that provides the following capabilities: --Application Performance Monitoring --Infrastructure and Network Performance Monitoring --Customer Experience and End User Monitoring	• Real-time contact center response time reporting vs. hourly reporting • Improved user interface - dashboard view vs. emailed report • Visibility into the smart energy application network • Targeted troubleshooting and faster root cause analysis • Deep-dive analytics and drill-down capability • Exception alerting capability • Auto-discovery, low configuration solutions (i.e., less administrative work) • Reduce Waste	18-Mar	(1.00)	44,600	0	0	18,887	15,179	0	10,534	0
102	2018	ARP - Collaboration Asset Refresh	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is for the refresh of the Company's Collaborative tools such as Telephony Systems, Video Conference Systems and Digital Whiteboard systems.	This project provides value by insuring the tools used by employees to communicate and conduct business activities are modern and reliable. Customers benefit as the business is more effective when communication systems are reliable and available.	18-Dec	(0.95)	1,105,109	299,100	323,015	173,550	226,980	0	82,464	0
103	2018	ARP - Operational Technology Support	Upgrades & Replacements (Enterprise)	Network	Electric T&D, Gas T&D, Generation	Asset refresh project for infrastructure supported by CIS. Replace assorted critical infrastructure due to obsolescence hardware as identified per 5 year budget planning/forecast. IT provides both hardware and labor funding.	The requirement is to replace and upgrade the in scope items with current technologies. The project will replace functionality without necessarily doing a like-for-like replacement of the asset. For example, instead of replacing 20 servers with 20 servers, converged infrastructure will be implemented.	20-Dec	(1.04)	1,826,678	58,200	1,461,106	21,687	0	0	285,685	0
104	2018	ARP - Elimination of Carrier Based Analog Access Lines	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is to replace the approximately 1,600 analog telephone lines with AT&T, Frontier and TDS Metrocom with cellular voice service. These lines are used to for meter reading, telemetry, elevators, building systems fire/alarm panels and monitoring, and site emergency back up. AT&T has announced that they will be dropping this service in 2020.	Replace legacy analog telephone service with cellular technology to mitigate the impact of increased costs due to reliance on old obsolete technology.	18-Nov	(0.98)	260,142	0	0	10,000	0	0	250,142	0
105	2018	ARP - F5 Refresh	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project will refresh the company's F5 Load Balancing equipment. The F5 hardware was purchased in 2011 and the industry average refresh cycle is 5 years.	1) Refresh obsolete F5 equipment. 2) Determine required feature sets for new Load Balancer. 3) Implement new F5 according to industry best practices.	18-Jun	(0.96)	93,713	0	0	9,312	0	0	84,401	0
106	2018	ARP - Field Device Asset Management (FDAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy field devices on a four-year refresh cycle. Field Devices typically last 4 years before we start having technical issues with the units. Completing the refresh will mitigate potential costs for hardware repairs, and allow Field Workers to complete their job tasks.	Field Workers require these rugged devices to complete their daily job tasks in support of our customers. Benefits of the ARP Field Device Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Reduced potential impact to our customers - Increased system performance such as speed, battery life, etc... - Increased CE employee opportunity to exceed expectations of our customers. - Less impact on future years for capital refresh requests, just pushing the issue if we delay	18-Dec	(1.09)	1,531,428	0	1,215,726	41,147	0	0	274,556	0
107	2018	ARP – Network Monitoring	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project will refresh and add additional Network Monitoring capabilities. The equipment that is refreshed in this project is used for the monitoring and troubleshooting of our applications and services at Network level.	The scope of this project is monitoring of the Company's internal Networks to insure the optimal performance of systems that are used to provide services to our Customers.	18-Dec	(1.12)	498,284	0	349,200	93,120	0	0	55,964	0
108	2018	ARP - Printer Asset Management (PAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy printers, plotters, and multi-function printing devices on a five-year refresh cycle for every department in the company. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older printers to complete their job tasks.	Employees require these printers/plotter to support their business efforts in support of our customers. Refreshing the equipment provides these benefits: - Reduces equipment failures reducing downtime for CE employee and meeting our customer expectation - Ensures printers can provide expected functionality with our print application meeting our customer expectations - Refreshed hardware allows Workstation software to function as designed reducing employee downtime and meeting customer expectation Customers are assured that our Call Centers and Dispatch centers have the required printing capabilities to meet our customer expectations	18-Dec	(1.05)	737,129	0	575,898	42,681	0	0	110,644	7,905

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109	2018	ARP - Server	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	IT server infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT Infrastructure. This Server Asset Refresh Project (ARP) project will evaluate Computer Hardware with more than 5 years of continuous use and replace where appropriate.	The project will intelligently and systematically replace critical infrastructure before a system failure that would disrupt business operations. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers	18-Dec	(1.04)	1,020,974	0	0	62,905	928,603	0	29,465	0
110	2018	ARP - Storage	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	IT storage infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT infrastructure. This storage Asset Refresh Project (ARP) project will evaluate storage hardware with more than 5 years of continuous use and replace where appropriate.	This project is intended to address the ongoing refresh and storage growth needs within Information Technology regarding the data storage hardware. The project replaces hardware aged more than 5 years and provides incremental storage capacity where needed. The useful life of IT storage resources in a data center is 5 years. The project proactively replaces equipment after the useful life has expired to prevent unplanned outages and technology debt as well as ensuring capacity for growth. All Company business is performed based off IT systems. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers.	18-Dec	(1.06)	2,622,302	0	2,498,278	31,383	77,481	0	15,159	0
111	2018	ARP - Wireless Network	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is to refresh targeted portions of the Company's various wireless networks including the 800 MHz Radio System Infrastructure. Cellular telephones can be used to fill small voids but are a great hindrance to productivity as they are a 1 to 1 conversation as opposed to a one to many conversation as supported by the 800Mhz Radio System. Call setup time is greatly increased with the use of cell phones. Most radio conversations to an entire group of employees is in the 5 second range, which is often faster than the time it takes just to place a telephone call to a single employee. A prolonged outage to this system, whether caused by force majeure or human error, would impact our ability to restore services, direct crews efficiently, and has a high probability of becoming a safety issue.	The scope of this project is extending the useful life of the Company owned radio systems. It's primary focus is on the 800 MHz radio system proper but also includes other systems, sub systems and components used within the Company such as transmitters, mobiles, control equipment and to a smaller part supporting physical plant equipment - tower lighting systems, HVAC units, emergency power systems. The 800 MHz radio network that has been built and maintained by Consumers Energy is the main means of communication to our field crews.. The project provides value by insuring reliable and real time communication between company crews and dispatch locations. This benefits the customer by enhancing life safety and reducing the amount of time it takes to restore service.	18-Dec	(0.98)	953,985	0	602,709	13,774	70,616	0	266,886	0
112	2018	ARP - Workstation Asset Management (WAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy desktops and laptop computers on a four-year refresh cycle for every department in the company. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older desktops or laptops to complete their job tasks.	Benefits of the APR Workstation Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Increased system performance such as speed, battery life, etc... - Less impact on future years for capital refresh requests, just pushing the issue if we delay - Improves opportunity for CE employees to exceed expectations of our customers.	18-Dec	(1.06)	5,182,169	0	2,704,488	214,198	0	0	2,256,405	7,079
113	2018	Data Center 2.0 - Disaster Recovery	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	This is a Program to - * Mitigate the current significant risks (location risks, capacity risks, technology risks) with the Consumers Energy IT Disaster Recovery capabilities, by Collocating to a Backup Recovery Center (BRC) at a vendor facility and by enabling Disaster Recovery (DR) capabilities at full Production capacity, for all systems per when business requirements dictate full capacity * Mitigate the risk to Project/ Development activities when a DR event is in progress (as the project/ development environments are currently needed to be commandeered in case of a disaster) * Provide an environment suitable to perform expanded DR testing * Build a 100% Production capacity for DR purposes at Switch. At the end of the migration to Switch, the compute capacity at Switch will be >= the compute capacity at Parnall. Some of the capacity will be on newly purchased hardware and some will be on hardware shifted from the Battle Creek Data Center. Currently, there are no plans to put compute for Production DR in the Cloud.	Mitigate risks to the Corporation in the event of a Disaster, by significantly enhancing the Disaster recovery capabilities, DR testing capabilities, and scalability constraints at the current data center locations. Scope includes - 1) Both IT & OT Data Centers 2) Migrate BRC to a vendor Colocation data center 3) Expand DR systems capacity to support 100% Production load requirements 4) Expand DR capabilities to all applications that are determined by the business partners as needing DR Scope excludes: 1) Relocating Parnall Data Center to a Colocation facility	20-Dec	(0.82)	13,429,276	418,440	10,461,000	322,530	2,095,599	0	131,707	0

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114	2018	Dense Wave Division Multiplexing – Fiber Backbone Refresh	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	Refresh the company's Network hardware that is part of the Company's "Dark Fiber" network.	The scope of this project is to replace the existing Fiber Optic transport equipment at the ten Company locations that are part of the internal "Dark Fiber" network. This project provides value by insuring that the Company's internal Network connectivity for Call Centers, Computer Networks and the Radio Network is reliable and on modern, supportable hardware.	18-Sep	(0.99)	3,003,493	0	0	58,200	2,910,000	0	35,293	0
115	2018	ESB Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	The Enterprise Service Bus (ESB) is an Enterprise Integration Platform initially implemented to support the Advanced Metering Infrastructure (AMI) Smart Energy Applications. It enables secure flow of data from Smart Meter head ends to SAP and other systems that process and store the data.	Project scope is the upgrade all components of the enterprise service bus, and refresh underlying infrastructure as needed. This project will provide the users with more current versions of software to better meet business requirements. Additionally the project will resolve all current issues with application versions and infrastructure thereby saving expenditure on maintenance extensions and remediating risk due to unsupported technologies running in production.	20-Dec	(0.91)	1,975,068	0	265,000	433,000	966,000	0	311,068	0
116	2018	ITRON Enterprise Edition Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	The project will upgrade the Itron Enterprise Edition (IEE), which is the primary control software for bulk interrogations requests from AMI meters and bulk fulfillment of daily billing requests. It also performs validation, estimation and editing (VEE) functions for all data collected dial	Itron provides solutions that measure, manage and analyze energy utilization. The software upgrade will enable the Company to sustain these critical business operations on a current and supported version.	19-Feb	(0.93)	917,960	0	0	686,901	0	0	231,059	0
117	2018	Lotus Notes Application Migration & Retirement Wave 3	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Lotus Notes is an unsupported technology now at CE. Most of the 600+ LN applications can be moved to SharePoint, either from a direct move or customization. The applications are categorized into simple, medium, and complex. The migration is happening in 5 Phases or Waves and this is Wave 3.	This next phase will further enable capabilities on our current collaboration platform standard (SharePoint), while reducing the risk footprint of using an unsupported standard (Lotus Notes). SharePoint gives many new enhancements to these applications including collaboration, versioning of documents, security, and automated auditing. With the use of the K2 the users can also modify their own sites once migrated to better tailor them to their business needs.	18-Apr	(1.00)	40,444	0	0	0	37,549	0	2,895	0
118	2018	Lotus Notes Application Migration & Retirement Wave 4	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Lotus Notes is an unsupported technology now at CE. Most of the 600+ LN applications can be moved to SharePoint, either from a direct move or customization. The applications are categorized into simple, medium, and complex. The migration is happening in 5 Phases or Waves and this is Wave 4.	This next phase will further enable capabilities on our current collaboration platform standard (SharePoint), while reducing the risk footprint of using an unsupported standard (Lotus Notes). SharePoint gives many new enhancements to these applications including collaboration, versioning of documents, security, and automated auditing. With the use of the K2 the users can also modify their own sites once migrated to better tailor them to their business needs.	18-Dec	(0.97)	2,462,175	0	0	242,469	1,940,248	0	279,458	0
119	2018	OSIsoft Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	OSIsoft software is used to archive various data in a time series database for data analytics for various teams.	Provide data archiving for analytics purposes for the various groups that use the application. The following systems will be included in the scope of this upgrade: OSIsoft MODM implementation OSIsoft EDH implementation OSIsoft Generation Implementation – this includes the remote implementations to support the Solar Gardens SCADA data OSIsoft LVD\HVD implementation OSIsoft implementations at remote sites such as Lakewinds and Crosswinds OSIsoft Implementation for GAS AMR.	20-Oct	(0.94)	265,297	0	0	201,549	0	0	63,748	0
120	2018	OWCE Nitrogen Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Compliance & Risk Management	This project will Upgrade the OpenWay Collection Engine (OWCE) to the latest version. This upgrade will be done in parallel with the hardware asset refresh to reduce overall risk and cost.	OWCE is the head end software that communicates to smart meters. The upgrade to the Nitrogen version ensures that the Company sustains this critical business function on a current and supported version.	18-Oct	(0.98)	300,851	0	0	186,206	42,332	0	72,313	0
121	2018	Time of Use Billing	Upgrades & Replacements (Enterprise)	Software (Intangible)	Customer Management	Consumers Energy will be filing a rate order with the MPSC in May 2018 requesting that all residential customers who are currently being billed using register index reads be switched to a new Time-Of-Use (TOU) interval based billing rate.	Expand the current TOU billing rate available to all electric residential customers. Provides for all electric customers to be able to take advantage of the Time of Use (TOU) rate during peak period times without having to sign up for the program, thereby allowing them to save on their energy bill during this period.	19-May	(0.94)	3,128,171	0	0	1,476,939	780,000	0	871,232	0

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122	2018	Tumbleweed Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Upgraded system with support, redundancy, disaster recovery, a new test environment and additional capacity to comply with corporate operational standards to support critical business functions.	1. Upgrade Application from 5.1 to version 5.3.6 2. Create redundancy in Prod and Non Prod environments 3. Disaster Recovery 4. Increased Capacity 5. Training 6. Support Plan 7. Interfaces to other internal systems	18-Sep	(1.06)	115,478	0	0	43,458	57,124	0	14,897	0
123	**SUBTOTAL**	**2018 Upgrades & Replacements (Enterprise)**								**41,514,729**	**775,740**	**20,456,421**	**4,383,895**	**10,147,712**	**0**	**5,735,975**	**14,984**
124	2018	ED - ARP OSI HVD and LVD SCADA Upgrades	Upgrades & Replacements (Business Partner)	Software (Intangible)	Electric T&D, Gas T&D, Generation	The Electric Distribution (ED) Asset Refresh Project (ARP) upgrades OSII Supervisory Control and Data Acquisition (SCADA) application for High Voltage Distribution (HVD) and Low Voltage Distribution (LVD) systems. Biennial hardware refresh included.	Required to maintain the HVD and LVD electric SCADA grid.	18-Jun	(0.98)	127,997	0	0	26,065	81,880	0	20,052	0
125	2018	ED - Cyme Upgrade	Upgrades & Replacements (Business Partner)	Software (Intangible)	Electric T&D, Gas T&D, Generation	The CYME Distribution Analysis software is designed for planning studies and simulating the behavior of electrical distribution networks under different operating conditions and scenarios. It includes several built-in functions that are required for distribution network planning, operation and analysis. The Cyme solution currently runs on an unsupported version of software. The vendor has encouraged Consumers to upgrade, stating that they will not be able to support future problem resolution efforts. The software is currently loaded on individual workstations. Gateway will continue to reside on server. However, a network based solution to replace the PC based solution is not a feasible solution from Cyme. The scope of this project is to "replace in kind." Once upgraded, there will be the ability to evaluate other Cyme modules for their potential value for other departments.	The CYMDIST Distribution Analysis software is a suite of applications composed of a network editor, analysis modules and user-customizable model libraries. The program is designed for planning studies and simulating the behavior of electrical distribution networks under different operating conditions and scenarios. It includes several built-in functions that are required for distribution network planning, operation and analysis. This will also require an upgrade to Cyme Gateway (this will not require hardware/infrastructure changes. Consumers must utilize Cyme, or some other solution, in order to effectively perform load flow analysis that is critical to distribution planning, outage resolution. Cyme is a planning tool required in order to; effectively anticipate distribution load requirements, size protective devices, support grid modernization roll out. It is also used on a daily basis for switching analysis. If the software and platform are not upgraded, the vendor will not support future problem resolution, putting the ability to perform required analysis at risk.	18-Jun	(0.95)	205,368	0	0	117,034	46,208	0	42,126	0
126	2018	eSOMS - upgrade to Operations Management	Upgrades & Replacements (Business Partner)	Software (Intangible)	Work Management	Upgrade eSOMS solution to current version is on a new platform and older versions will no longer be supported. New functionality will be enabled, as well as new mobile capabilities will be implemented. eSOMS is critical to safety in Energy Resources as it facilitates and provides controls for the Working Clearance process which protects workers from energy sources while working on equipment per OSHA requirements. eSOMS is also used to facilitate the recording and utilization of plant operational logbooks, and to facilitate equipment rounds performed by plant operators.	Upgrade eSOMS to the version renamed Plant Operations 6.0. New version includes new functionality for Tracking and Control. Add mobility technologies and purchase mobile devices. Maintain vendor supported version. Enable mobile capabilities for key users (improved usability of solution with improved accuracy and timeliness of data)	18-Aug	(0.88)	288,979	13,600	67,242	100,918	40,633	0	66,587	0
127	2018	GIS-Integrated Design	Upgrades & Replacements (Business Partner)	Software (Intangible)	Work Management	This project is to replace the current CAD/Work Requirements and Design software with a GIS based design tool for improved capabilities in the preparation of graphical designs for the order fulfillment processes for gas and electric work orders.	New functionality in scope: Ability to directly integrate with multiple ESRI databases, read data and attribution form dataset to begin design, Send data to proper data set (ESRI), electric and gas design simplification tools (streamline the actual placement of materials and attribution into a design), consumer GIS data as a service in addition to directly connect data (Replace WRaD Robosync), creating synergy for new construction of being able to send an updated design file with the corresponding updates and attribution to the GIS improving the as-built (redlining) posting process.	18-May	(0.95)	2,913,108	0	0	372,785	1,407,368	0	1,132,955	0
128	2018	Integrated Resource Planning (IRP)	Upgrades & Replacements (Business Partner)	Software (Intangible)	Energy Portfolio Planning	Energy Policy requires Integrated Resource Plan be filed. Solution selected will enable scenario driven, long term, economic capacity planning, production cost modeling, evaluating future years for as is & potential changes in future energy landscape.	Advanced capacity/cost modeling to meet energy policy IRP requirements. Replace/upgrade obsolete tools being used to ensure latest simulation data, modeling capability with capacity expansion considerations for portfolio optimization.	19-Apr	(0.92)	129,539	0	0	98,627	0	0	30,912	0
129	2018	LandWorks Property Management System Upgrade V5.5	Upgrades & Replacements (Business Partner)	Software (Intangible)	Asset Management	This project is to upgrade the Land Property Management System (LMP by LandWorks) to the next version, as well upgrade to ArcGIS in order to support the version upgrade.	Application is currently on an older version and at risk of no longer being supported by vendor.	18-Oct	(0.90)	35,255	0	0	9,277	22,328	0	3,650	0

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130	2018	Operations Application Currency	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	This effort is needed to ensure application currency for the Operations (Gas, Electric & Generation) Application Portfolio. The application upgrades have been prioritized based on business criticality and value, and this project will perform the routine upgrades/maintenance to ensure IT solutions supporting Operations business processes to deliver energy to our customers are stable and current.	The Operations Application Portfolio went through an assessment to evaluate application currency and technology obsolescence for this portfolio, prioritized needed upgrades based on business criticality and value, and this project was initiated to address priorities to ensure appropriate support and performance.	19-Dec	(0.94)	84,386	0	84,386	0	0	0	0	0
131	2018	PowerPlan Upgrade	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	This project is to upgrade the functionality in PowerPlan to the latest version and properly address the new Leasing GAAP regulatory requirements for 2019	Upgrade the functionality in PowerPlan to handle the end of life, accommodate the new Leasing GAAP regulatory requirements effective 2019 and enable month-end close accuracy and automation through the financial close cockpit. Required to continue support and to comply with GAAP regulatory requirements.	19-Jan	(0.96)	1,975,654	68,345	0	439,009	1,171,981	0	296,319	0
132	**SUBTOTAL**	**2018 Upgrades & Replacements (Business Partner)**								**5,760,287**	**81,945**	**151,628**	**1,163,715**	**2,770,397**	**0**	**1,592,601**	**0**
133	2018	AccessNOW	Security	Software (Intangible)	Administrative & General (A&G) Support	Implementation of configurable Identity and Access Management for systems and best practices with enforced compliance. (Formerly Dell 1 Identity Manager)	This includes enterprise level foundation architecture, technology and end-2-end processes and controls. Processes will be fully automated user self-service and access lifecycle management. The project will deliver integrated and synced enterprise authoritative data.	20-Sep	(0.92)	1,130,181	0	0	368,897	245,276	0	516,008	0
134	2018	ARP - Cyber Security	Security	Network	Compliance & Risk Management	The objective for Cyber Security Asset Refresh project is to ensure continued vendor support of security technology deployed at the Company as well as reduce the risk of unplanned outages due to outdated hardware/software and appliances.	Replace end of life and obsolete systems; leading to less probability of equipment failures, software compatibility issues and business partner downtime.	18-Dec	(1.09)	622,110	0	56,406	0	0	0	565,704	0
135	2018	Firewall Management Platform	Security	Software (Intangible)	Compliance & Risk Management	The project will implement a firewall management platform.	Cyber security now manages nearly 100 firewalls and keeping configurations up to date, changes processed correctly and mistakes to a minimum is challenging. A firewall management platform will enable automation and workflow to provide greater security and efficiency for our team. Firewall security mistakes and failures are leading causes of data breaches.	17-Jun	(0.98)	44,190	0	0	12,902	27,478	0	3,810	0
136	2018	Mass Notification	Security	Software (Intangible)	Compliance & Risk Management	Provides the capability to communicate with desktop servers (send an alert out to desktops); and to activate a “Blue Light” at the service centers during an event (active shooter/lockdown, etc.…) via the MNS system;	Implement/upgrade Siemens Fire-Panels at company locations. Similar to current capabilities used to announce "fire" events, the mass notification tool will allow notifications for other events requiring notification to building participants. This is directly tied to employee safety. Safety is increased by allowing better communications to employees during emergency situations.	18-Dec	(1.06)	1,250,055	69,470	45,627	0	1,097,709	0	37,250	0
137	2018	NERC/CIP Version 5	Security	New Computers / Hardware	Compliance & Risk Management	Regulations required Consumers Energy to be compliant with NERC Critical Infrastructure Protection (CIP) standards. This project is chartered to bring critical infrastructure into compliance with NERC/CIP standards.	Key project scope includes completing requirements to meet NERC CIP requirements (Version 5), which include: Identify and classify BES Cyber Assets and develop preventive, detective, and corrective controls as they apply to the NERC CIP Version 5 Standards.	18-Sep	(0.96)	558,382	0	105,500	121,768	43,120	0	287,994	0
138	2018	OT Security Architecture	Security	Network	Compliance & Risk Management	IT Information Security is taking responsibility for Cyber Security within various areas of the businesses' Operations Technology. The project will be used to implement a consistent security architecture across the Operational Technology landscape. Key scope includes the continuation of implementing the Consumers Energy OT security standard across the Generation fleet.	The project will be used to build a standard to house security requirements for Operational Technology architectures, identify controls that will have a high impact on cyber security at the plants, and implement consistent security architecture across the generation fleet. The lack of visibility into our operational sites increases risk of compromise. This project will build a standard to house security requirements for Operational Technology architectures, meet compliance requirements, identify controls that will have a high impact on cyber security at the plants, and implement consistent security architecture across the generation fleet.	19-Nov	(0.99)	953,736	0	100,000	280,333	0	0	573,403	0

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139	2018	Physical Security Hardware Refresh	Security	Network	Compliance & Risk Management	This project will ensure continued compliance with Federal Energy Regulatory Commission requirements as it pertains to physical security assets. The scope includes enhancement and replacement of physical security assets, as part of the lifecycle replacement program. This includes security cameras, motion detectors, intrusion detection systems and card access systems. The Company has several thousand cameras and card readers in use.	Implement security assets at company sites for a variety of reasons; One leading factor is the company's responsibility to stay in compliance with Federal Energy Regulatory Commission (FERC) regulations. Projects can include, but are not limited to; implementing advance door systems at company buildings, implementing security cameras for monitoring capabilities, implementing gate and lock systems, etc. An integrated solution is efficient and allows for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster, more effective/consistent response to emergencies and non-emergencies thereby reducing the likelihood of impactful security events to our customers.	19-Dec	(1.07)	1,225,692	0	0	5,713	109,996	0	1,109,983	0
140	2018	SAP Data Encryption Business Case	Security	Software (Intangible)	Administrative & General (A&G) Support	The project will implement Cyber Security requirements for encryption of Personal Identifying Information (PII) data "at rest" and "data in transit" in Company SAP data bases.	If we do not do this project, there is an increased risk of exposure of personal customer data if there is a breach. Currently this is an internal cyber security requirement, but there is also legislation in the works that will possibly make this mandatory. Alternative: Move to another SAP database technology which provides data encryption capability. This technology is being evaluated as part of the Planning phase of the project.	19-Dec	(1.00)	2,462,625	0	0	1,848,110	0	0	614,515	0
141	2018	SAP IDM Integration	Security	Software (Intangible)	Compliance & Risk Management	The Human Management Capital (HCM) component of SAP IDM (User Access Provisioning tool) will be configured to connect to the HCM modules of our applicable SAP environments (ECP, C7P, and S1P). This change will allow the SAP IDM tool to view and function with the HR organizational structure in SAP ECC, otherwise known as HCM. This will provide the tool the capability to automate access provisioning and de-provisioning to users in SAP via HR processes including onboarding, transfers, and termination. The workflows would be configured to execute based on HR triggers and actions.	Connect to the Human Capital Management (HCM) module in SAP ECC to perform the following: - Automate access provisioning and deprovisioning based on HR actions and triggers including onboarding and transfers. - Ability to view and manage access associated with HR components including Position IDs, org structures (CRM PPOMA), and business partner creation / management. - Enable the use of business roles in SAP IDM through configuration of HCM to respond to HR triggers. - Business role mapping to applicable business units.	18-May	(0.65)	867,701	0	0	0	0	0	867,701	0
142	2018	SAP Security	Security	Software (Intangible)	Compliance & Risk Management	The purpose of this project is to provide vulnerability scanning of SAP specific platforms. The project will include requirements gathering, vendor selection, product selection, tool design, configuration, and implementation. The benefit of this Project closes a gap as current information security vulnerability scanning tools do not provide the capabilities needed for new systems and solutions in our environment.	There is no functionality being delivered for this project in 2019. There is only a final payment associated with the project that will need to occur.	19-Dec	(0.97)	271,651	261,525	0	0	0	0	10,126	0
143	**SUBTOTAL**	**2018 Security**								**9,386,322**	**330,995**	**307,532**	**2,637,723**	**1,523,578**	**0**	**4,586,494**	**0**
144	2018	800MHz Tower Connectivity Optimization	IT Service Delivery	Network	Administrative & General (A&G) Support	Telecommunication providers have announced the discontinuation of leased TDM (Time Division Multiplexing) services (i.e. T1's) by 2020. All radio tower sites will need to migrate to alternate technologies before this date.	Maximize radio system availability to improve reliability, employee/customer safety, gas leak response, and response time to customer outages. Migrate to a newer network technology before existing T1's are no longer supported.	19-Nov	(0.94)	1,122,805	0	0	6,935	1,078,349	0	18,122	19,400
145	2018	e911 Compliance Project	IT Service Delivery	Software (Intangible)	Compliance & Risk Management	The project would enable each telephone handset to be capable of sending specific location information to the appropriate 911 public safety answering position (PSAP).	The state of Michigan regulations require that corporations provide a sufficiently precise indication of a caller's location so emergency response services may be dispatched to the specific location of the device. The corporation is required to provide a call back number. This means the PSAP that receives the 911 call from the corporation will be able to call back the location from which the 911 call was placed, if needed. The corporation is also required to provide a specific Emergency Response Location which shall no larger than 7,000sq ft. (all buildings and campus).	18-Oct	(0.96)	490,580	0	0	20,643	0	0	469,937	0

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146	2018	Nimbus Phase 4	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	Nimbus Phase 4 will be adding additional features to Nimbus, including improving the integration between Nimbus with a Public cloud provider of our choice, application containerization, storage provisioning, and VDI deployment. o The ability to provision storage as needed by servers. Currently when storage runs out, storage engineers need to provision storage to those servers. o Public Cloud Provisioning: The ability to provision new public cloud resources. o Base automated reporting o Container support o VDI deployment o Reactive healing o DMZ (network zone) deployment	The ability to deploy resources in a public cloud. The ability to automatically provision storage for servers. Deployment of VDI VMs. Base container deployment and management. Base automated reporting. The ability to automatically reactively heal existing Virtual Machines (VMs). The ability to deploy into the DMZ (network Zone).	18-Nov	(0.98)	1,167,282	0	348,700	418,440	163,540	0	236,602	0
147	2018	SAP Archiving	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	With SAP being the company's primary Enterprise Resource Planning (ERP) platform for the integration of business processes, the daily system usage has resulted in massive amounts of data to be stored in SAP. Currently the size of the SAP ECC database alone is 23TB and is growing.	(1) Meet compliance requirements by purging any data that can become a liability as identified by CE legal team (2) Build an Archiving solution that allows the business to retrieve archived data with ease and in the form that is needed	18-Dec	(0.93)	353,979	0	121,233	19,109	184,694	0	28,943	0
148	2018	TCoE Automated Testing 2018 - SAP Regression	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	This project will continue to automate test scenarios that are frequently used in SAP regression tests to ensure that changes being introduced, such as SAP support packs or SAP enhancements, do not adversely impact existing functionality.	The value of automated testing is reduced regression testing time and effort, which leads to better quality service to our customers and employees. This is a continuation of the 2017 test automation effort, breaking up the scope into manageable chunks.	18-Aug	1.04	226,904	0	0	171,560	0	0	55,344	0
149	2018	TCOE Test Data & Environment Management	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	The purpose of this project is to implement the tool(s) and techniques to be able to periodically (e.g. annually) refresh our data in our SAP development and QA environments from production. It is a continuation of the work started in 2018. Our SAP test data is stale. Our SAP development environments have never been refreshed and our QA environments can go 5+ years without refreshes. This results in slower delivery since much time is needed to find and update data. This can also impact quality since testing is sometimes limited based on test data constraints especially in the development environments.	With improved SAP test data, our manual testing efforts will decrease, improving speed to deliver and reducing costs. Further, the quality of testing will improve and therefore the quality of the solutions will improve. This is true for all SAP applications and SAP interfacing applications including customer applications such as CRM, our CE.com web site and customer billing.	19-Jun	(0.94)	1,119,282	0	0	0	0	0	1,119,282	0
150	**SUBTOTAL**	**2018 IT Service Delivery**								**4,480,832**	**0**	**469,933**	**636,687**	**1,426,583**	**0**	**1,928,230**	**19,400**
151	2018	Enhancements - Corp	Enhancements	Software (Intangible)	Administrative & General (A&G) Support	Small software enhancement work efforts performed for Corporate and Shared Services business areas.	Each enhancement request has defined business value.	18-Dec	(0.90)	508,194	0	0	0	0	0	508,194	0
152	2018	Enhancements - Cust Exp-Ops	Enhancements	Software (Intangible)	Customer Management	Small software enhancement work efforts performed for Customer Experience business areas.	Each enhancement request has defined business value.	18-Dec	(0.98)	921,820	0	0	159,005	379,973	0	382,842	0
153	2018	Enhancements - TEOS	Enhancements	Software (Intangible)	Administrative & General (A&G) Support	Small software enhancement work efforts performed for the DCO business area. These can be capital if done for SAP or BI and meet software capitalization criteria. Those that don't qualify as capital will be charged to O&M.	This is a conglomeration of multiple small work efforts each with their own risk if not completed. Work is requested, defined and approved for work by governance boards throughout the year	18-Dec	(0.98)	541,197	0	0	0	340,623	0	200,574	0
154	2018	Enhancements -Operations	Enhancements	Software (Intangible)	Work Management	Small software enhancement work efforts performed for the ER business area.	Each enhancement request has defined business value. 2017 & 2018 Requests Include: FERC Market Based Rate Filings GCC – Mass move for Suppliers SAP Catalog 'B' Addition Request SAP Functional Data Fields - System Owner Met/Team customer portal external	18-Dec	(0.96)	392,055	0	0	0	0	0	392,055	0
155	2018	Manage Rev Acct - Mg Rev Assurance (PID/FACTA)	Enhancements	Software (Intangible)	Administrative & General (A&G) Support	Reduce reliance on manual adherence processes from Revenue Recovery to bring us into compliance with billing rules and practices. This project will use system changes to enforce compliance and reduce the risk of MPSC investigations and fines (per Amy, D	Improved process efficiencies and customer satisfaction: Increase service capabilities in Contact Ctr (e.g., First call resolution)	18-Nov	(0.98)	250,583	0	0	0	0	0	250,583	0
156	**SUBTOTAL**	**2018 Enhancements**								**2,613,849**	**0**	**0**	**159,005**	**720,596**	**0**	**1,734,249**	**0**

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
157	2018	5 Minute Settlements	BP Functionality	Software (Intangible)	Energy Portfolio Planning	PCI Back Office Suite, PCI Profit and Loss Analyzer, PCI Settlement Analyzer, PCI Energy Accounting, EA Data Mart, and GenTrader require a major redesign and upgrade to support the new MISO 5-Minute Settlements solution (Requirement of FERC Order 825). Moving to 5 minute intervals for data will result in a significant increase in database size, requiring new hardware/OS for database servers.	In order to continue settlements with MISO, and to meet requirements of FERC Order 825, this upgrade is required by April 1, 2018. Not completing this work would have negative financial and compliance implications.	18-Oct	(0.95)	145,091	141,851	0	1,744	544	0	953	0
158	2018	BPC Automation and Reporting	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	BusinessObjects Planning Consolidation project provides version upgrade that allows for functionality for automation of data loading and reporting. New functionality for data ad hoc analysis for gas/electric price volume and general ledger validations.	Provide version upgrade that allows for functionality for automation of data loading and reporting.	18-Apr	(1.02)	158,722	0	0	36,265	101,123	0	21,335	0
159	2018	Business Continuity Disaster Recovery Integration	BP Functionality	Software (Intangible)	Compliance & Risk Management	Implement technology solution and supporting processes to integrate the Company's business continuity and disaster recovery programs to enhance program efficiency and effectiveness.	Solution will improve program management and drive efficiency with the following: o Plan management repository with workflow capabilities (in support of plan development/review, training and testing requirements o Maintain program schedules, monitor status and reporting capabilities o Risk analysis and interdependency mapping of critical business processes and IT applications o Flagging mechanism to ensure identification of restoration capability gaps to critical business processes and/or IT recovery capabilities o Business Impact Analysis (BIA) capabilities to quantify financial risks to critical process disruptions	18-May	(0.74)	204,820	0	0	23,712	10,112	0	170,996	0
160	2018	Contact Center Customer Experience Refresh	BP Functionality	Network	Customer Management	Comprehensive refresh of the Customer Call Center's IT infrastructure, including the three Automatic Call Distributor (ACD) systems, networking equipment , IVRs, Work Force Management, servers, and applications. The ACD Systems are 10 years old in 2015 and cannot readily adapt to best practice. Additionally, they are no longer vendor supported and hardware replacement parts are not available.	Speech enabled interactive voice response (IVR) Customer Service Representative Knowledge Management email Management Call Center Quality Monitoring Optimize Skills Based routing Customer Analytics Enhancements Multi-Channel Inbound & Outbound Communications Virtual Hold Click to Call	18-Apr	(0.55)	1,443,005	302,640	0	187,986	669,766	0	282,614	0
161	2018	Corporate Capital	BP Functionality	New Computers / Hardware	Administrative & General (A&G) Support	The capital is used to fund expenditures for senior officers, corporate officers, and corporate departments. In the past capital has been focused in the areas of IT equipment and related peripherals, video equipment for the Communications team, and facilities (furniture and officer/director moves). Small corporate expenditures that meet the spending threshold for capital, but not projects - No business case document	To meet the emergent, IT, and facility needs of the corporate area, and support the overall utility. Hardware nearing the end of lifecycle. Officers and new employees will be using new equipment to access their work to maximize productivity. Meeting the emergent IT needs of the corporate area ensures continuity of business processes. The facility office moves will increase the productivity of teams by grouping them together following a re-organization.	18-Dec	-	396,000	0	396,000	0	0	0	0	0
162	2018	Credit and Collections	BP Functionality	Software (Intangible)	Customer Management	Investigate ways to leverage IT applications to support the lowering of uncollectible expense goals. Payments are uploaded and credit to a customers account automatically and efficiently. Examples are : SaaS (DebtNext) This would be to manage campaigns/channels etc. across the entire portfolio of Active, Final and Written-off. Technology Benefits: DebtNext - Cloud computing vs IT resources, customize system to meet business needs People Benefits - DebtNext - Real time decision support with reporting options provided Enhanced Communications - Easily understand, new communication channels (i.e. Postcards) Process Benefits - DebtNext - would manage third party collections vendors and accounts placed with them. What we "need to do" not "what we have done" Financial Benefits - DebtNext - Reduce Cost and improve operations.	Technology Benefits: DebtNext - Cloud computing vs IT resources, customize system to meet business needs People Benefits - DebtNext - Real time decision support with reporting options provided Enhanced Communications - Easily understand, new communication channels (i.e. postcards) Process Benefits - DebtNext - would manage third party collections vendors and accounts placed with them. What we "need to do" not "what we have done" Financial Benefits - DebtNext - Reduce Cost and improve operations. Audit trail. / Reduce collectibles; Better visibility on age of inventory; Ability to move accounts	19-Nov	5.00	148,040	0	0	1,798	1,001	0	145,241	0

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Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
163	2018	Customer Experience Improvements	BP Functionality	Software (Intangible)	Customer Management	New Outage Center (Phase 1 & 2): Redesign and facilitate customer outage reporting and provide restoration information delivery Move-In Move-out: Improve and expand customer move-in processes Billing & Payment Field Capability: Provide field ability to invoice and pay customers Content Personalization (incl rates experience): Provide customers increased awareness of rate options Gas Leak Response Tracker: Customer safety and response tracking information for gas leaks Integrated Rates Experience/Interval Data Portal Replacement: Replace unsupported interval third-party provider (SSN) Super User: Facilitate payment and mgmt of customers with multiple business accounts	New Outage Center (Phase 1 & 2): Location-specific report identification and restoration tracking; Move-In Move-out: Improve customer address matching and expand scope to business customers; Billing & Payment Field Capability: Provide field invoice and payment acceptance functionality; Content Personalization (incl rates experience): Provide rate information options and customer education; Gas Leak Response Tracker: Expedite customer safety awareness and resolution tracking for gas leaks; Integrated Rates Experience/Interval Data Portal Replacement: Enhance and migrate customer interval usage information Super User: Facilitated account management and payment for business customers	19-Dec	(0.67)	2,430,587	104,610	0	871,750	411,466	0	554,581	488,180
164	2018	DCE Website Replacement_R3B 2017	BP Functionality	Software (Intangible)	Customer Management	This project release will implement Sitecore Version 8.2	• Version 8.2 is a significant upgrades to the current 7.5 version. It provides: o Website analytics to help identify opportunities to improve site traffic and performance. This includes "value" assignment for advanced target marketing capabilities o Includes launch of a "forms" module that will help accelerate development of online forms that allow customers to complete transactions on the new website o Will improve website performance	18-Oct	(0.97)	203,453	0	0	63,618	95,906	0	43,928	0
165	2018	DCE Website Replacement_R3C 2017	BP Functionality	Software (Intangible)	Customer Management	This project release will implement Profile Update/Profile Wizard	• Will create a new "create profile" and "profile update" user flow that introduces customers to Consumers Energy service options and will remind customers when their profiles are incomplete. o This first version will include alerts, ebill and choose due date. o Subsequent versions will include EE/RE options and rates. Additional options are expected to be added.	18-Nov	(0.84)	1,454,203	0	0	465,036	742,820	0	246,347	0
166	2018	Dispatch Voice Recording	BP Functionality	Software (Intangible)	Work Management	The project will implement the ability for Distribution Gas and Electric Dispatch to record phone conversations.	The recorded phone conversations will be used to address safety concerns, incident investigations, provide background for training classes, and coaching.	19-May	(0.90)	65,443	0	0	49,515	0	0	15,928	0
167	2018	DRAM Risk Model for DIMP	BP Functionality	Software (Intangible)	Compliance & Risk Management	The Distribution Integrity Management Program (DIMP) project will install and configure DNV GL's Uptime Risk Manager software with the Distribution Risk Analysis Model (DRAM). The Mains Replacement Prioritization software was purchased by Consumers Energy from Advantica (now DNV GL) and implemented in 2010 as a Distribution Integrity Management Program compliance tool. At the time of the purchase, the vendor was just about to come out with it's next release. We have been using the MRP software since then, but we need to move to the newer version to incorporate some of the tools the MPSC is looking for us to have in a DIMP program.	This project was going to be included in the TIMP project, but due to our version of ESRI GIS being too outdated, DNV GL would not support the DIMP software on our existing platform. DNV GL has migrated the platform for DIMP from MRP to a Risk Engine combined with a Distribution Risk Analysis Model. The MRP software is now just used for prioritization of main replacement and not so much of the risk analysis model. For this reason, DNV GL has agreed that what we actually bought rights to is the combination of the Risk Engine and DRAM instead of just an MRP upgrade. This project is to install those pieces of software and configure their interface with our GIS system.	18-Dec	(0.96)	642,306	0	0	480,857	0	0	161,449	0
168	2018	ECM-ProjectWise	BP Functionality	Software (Intangible)	Asset Management	This ECM (Engineering Content Management) project is to investigate and install drawing management software capable of bundling, managing and handling the versions of Gas records/documents related to design, proposals, contract resources and record-keeping.	The solution will be capable of bundling, managing and handling the versions of documents related to design, proposals, contract resources and record-keeping. 1. It must be able to render, as one document, drawings that are composed of several files, as is the case with many CAD drawings such as those produced in Microstation and AutoCAD software. 2. It must be able to maintain spatial relationships within drawings and documents such that all documents pertinent to a geographical location can be quickly located and maintained. 3. It must be able to integrate with Microstation, Microsoft Office, AutoCAD, SharePoint, SAP and potentially other systems.	18-Mar	(0.95)	196,128	0	0	18,760	153,637	0	23,731	0

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169	2018	EHS Compliance	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	Implement solution with modules capable of providing audit, corrective action plans, workflows. Data management for water discharge, air emissions, waste management, key calculations, Regulatory intake, Safety incident, near miss tracking, Dashboards.	Need to move the knowledge from people to the process and this tool facilitates that. The Environmental Services and Safety departments are in need of a consolidated solution for managing EHS compliance and tracking performance. The Environmental Services and Safety departments are currently using several solutions, both custom and packaged, for housing EHS information, task management, and report creation. The data from these solutions is not integrated, and must be collected and consolidated manually for regulatory reporting or other EHS compliance-related activities.	19-Feb	(0.59)	798,268	0	0	607,777	0	0	190,491	0
170	2018	Enhanced Customer Data Analytics Platform	BP Functionality	Software (Intangible)	Customer Management	Create a comprehensive and holistic analytical view of a customer encompassing interactions, programs, outages, bills, payments, usage, research and feedback data.	Comprehensive view of customer across customer classes and size enabling customer segmentation and analytics. Initial scope includes: Rates, Billing History, Payments, Payment Channels, etc. Provide a Single Source of Truth for all of the customer interaction data with the utility, as well as their feedback and customer research.	19-Nov	(0.97)	2,480,863	0	0	303,983	414,075	0	1,762,805	0
171	2018	Enterprise Content Management	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	Provide an Enterprise Document Management solution including the strategies, tools, and processes to more easily manage, rapidly locate, and deliver CMS Energy content throughout its life cycle wherever that content exists into the form the business partner needs. Areas needing this include: Legal. Risk and Insurance, HR, Strategic Communications, Learning and Development, Distribution.	Provide an Enterprise Content (document) Management solution including the strategies, tools, and processes to more easily manage, rapidly locate, and deliver CMS Energy content throughout its life cycle wherever that content exists into the form the business partner needs. Content management enables organizations to enforce policies and rules for the retention and disposition of content required for documenting business transactions, in addition to automating the management of their record-retention policies. These technologies, implemented with well-formulated and consistently enforced records retention policies, form an essential part of the life cycle management of information. As industry regulation and compliance requirements increase, along with the volume of digital content that must be retained and the demand for legal discovery.	18-Dec	(0.96)	2,011,903	0	0	0	0	0	2,011,903	0
172	2018	FERC Reporting Tool	BP Functionality	Software (Intangible)	Compliance & Risk Management	The project will create an XML format for quarterly FERC 3-Q & FERC Form 1 reports.	The Company currently uses the FERC Form 1 Submission software Visual Fox Pro. This software is provided by the FERC at no cost. The FERC is beginning the process of moving away from Visual Fox Pro as it is no longer being supported by Microsoft as of January of this year. The Company will be required to switch to an XML format and will need to be responsible for creating our own system in house or using a 3rd party vendor to create software for us to be able to upload the required data/pages to FERC in the XML format.	18-Nov	(0.94)	86,984	0	0	32,488	0	0	54,495	0
173	2018	FSS Release 4 - Appointment Booking & R9 Upgrade	BP Functionality	Software (Intangible)	Work Management	The Project will add functionality to the SAP/Service Suite systems to allow the Call Center and Scheduling groups to provide 3 hour (ultimately 2-hour) appointment windows for customer booking of service appointments. This project also includes the upgrade	This project is targeted to provide the following: 1. The ability to provide 3 hour (ultimately 2 hour) service appointment windows. a. Provides a smaller wait time for customers for CE field employee to arrive and work 2. The technical upgrade	18-Dec	4.32	1,152,313	0	34,870	709,862	165,038	0	242,543	0
174	2018	Gas & Electric Meter Operations	BP Functionality	Software (Intangible)	Work Management	This project will be to implement additional enhanced operations for smart energy. It would include the following functions: This release would be planned to take 17 months from the point we start the project and approximately 12 months of elapsed time. This release will also contain a mix of business, technical functionalities coupled with architecture and infrastructure items. The items included are detailed further below. The numbers in the brackets are a reference to the SES ID in the Scope Matrix.	Technical Architecture (33) • Direct Load Infrastructure – Infrastructure for the Demand Response Management System (DRMS), Third Party DLA Application and or any Information System selected • Secondary Site Infrastructure – This is a continuation of the DRC implementation which was released for the single site in Release 4. Capgemini will come up with architecture for infrastructure deployment of the new Information Systems like DRMS on a dual site failover mode and align the existing applications' infrastructure to fail over in a secondary site if required by the Business Continuity Plan. We will also confirm that there is a plan to do the same (if not already there) for the existing Information Systems.	18-Jan	(1.02)	123,793	0	0	63,977	-1,439	0	61,255	0

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175	2018	Generation Engineering Records Management	BP Functionality	Software (Intangible)	Asset Management	This project is to implement a "system of record" drawing/records management software to manage generation assets, that is capable of bundling, managing and handling the versions of drawings and documents related to design, project files, and construction.	The solution must be capable of bundling, managing and handling all of the versions of documents related to design and record-keeping. Benefits will be primarily realized by everyone involved in Generation and Gas C&S Engineering. (500 individuals).	18-Dec	5.00	561,483	0	0	421,578	0	0	139,904	0
176	2018	GM - Distribution Management System - Release 1	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	The scope of this portion of the DMS is implementation of OSI's eMap solution. It includes integration with GIS and is a foundational component for the broader implementation of a comprehensive DMS/ADMS. The purpose of this project is to implement the first release of a Distribution Management System (DMS). OSI Modules to be implemented include: - Distribution Network Operating Model (eMap) - GIS Interface	This module will provide the foundation necessary for the broader implementation of a comprehensive DMS. A DMS system is an electric network management sol. that provides advanced functionality in distribution grid analysis, oper. and restoration	18-Nov	(0.99)	526,682	0	238,245	120,000	101,000	0	67,437	0
177	2018	GM - Electric System Model Enhancement	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	Implement an Electric Grid System Model that will support the current and future needs of GIS, OMS, DPS (CYME), DMS and GIS Integrated Design Tool. The Electric Grid System Model will be designed and implemented to serve as an extensible platform to efficiently and effectively manage and share the Electric GIS network model information with the rest of grid operational and planning systems. Establish a methodology for integration that will connect Electric GIS, SAP, Cascade and other Asset Management Systems in a common way to provide an integrated view of assets across asset management areas.	The Project will achieve the following high level objectives in support of the Grid Modernization Program: (no specific order) 1. Capture all primary and secondary pole locations within one (1) meter accuracy and reconcile the existing EGIS connectivity model to these locations to support DMS and other advanced applications. 2. Evaluate and enhance EGIS integrations with SAP and OMS to provide a more flexible support model and data accuracy in preparation for DMS by following Consumers Energy's integration standards and where applicable leverage the IEC 61968 CIM standards for integration and common networked model exchanges. 3. Consolidate disparate electric distribution GIS databases into a common shared electric GIS platform. 4. Implement change management associated with business processes for managing all electric distribution map records. 5. During execution of the project, all EGIS integrated processes will continue to operate without unplanned disruption.	18-Jun	(0.97)	84,999	0	0	37,200	36,243	0	11,556	0
178	2018	GM - GIS Connectivity Model Integration	BP Functionality	Software (Intangible)	Electric T&D, Gas T&D, Generation	An end to end integration to publish the GIS connectivity model from GIS to the Tibco ESB, leveraging the CIM standard. Create a service delivery point based asset framework in the MODM historian.	Interface Reference Model (IRM) for Grid Modernization Program. Touchpoints and logical interfaces have already been developed to support a DMS. Integration to TIBCO and supporting adaptors. MODM will subscribe to the ESB	19-Jan	(1.02)	401,993	0	0	155,500	184,000	0	62,493	0
179	2018	GM - Grid Communication Modernization	BP Functionality	Network	Electric T&D, Gas T&D, Generation	Verizon has announced that they will no longer offer their analog, multi-drop phone service as of February 28, 2015 and their Frame Relay service after December 31, 2015. These services are an integral component of the SCADA communication infrastructure.	A wired and wireless solution to replace Verizon's sunsetted services (analog multidrop circuits and frame relay circuits). Defined minimum and uptime requirements. Sufficient site coverage.	18-Dec	(0.98)	650,690	37,500	90,871	296,660	132,699	0	92,959	0
180	2018	Hydro Network Improvement/Connectivity Upgrade	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	Provide reliable corporate network connectivity to three non-headquarter, Hydro-Electric Generation sites. Along with appropriate bandwidth necessary to deliver acceptable network performance for the Hydro Control and Monitoring System (operational technology), SAP, eSOMS, SharePoint, and other critical applications. Three Hydro/Dam Sites: Rogers Cooke Foote	The benefits of this project include: 1. Provide reliable business and operational network connectivity to the ten non-headquarter, hydro-electric generating sites. Along with the bandwidth necessary to deliver commonly acceptable network performance for the Hydro Control and Monitoring System (operational technology), SAP, eSOMs, SharePoint, and other critical applications. 2. The networks must be available and reliable as they are an integral part of the Hydro Monitoring and Control System. For example, the Rogers, Hardy, and Croton sites (along the Muskegon river) plant control systems are each interdependent on inputs from the others to control within regulatory requirements. 3. To achieve expected productivity, hydro operators must be able to use their critical applications like eSOMS, SharePoint, and SAP while physically at any of the hydro generation sites.	18-Nov	(1.06)	42,520	0	0	31,500	0	0	11,020	0

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181	2018	Incident and Risk Management	BP Functionality	Software (Intangible)	Compliance & Risk Management	Implement corporate-wide incident and risk management tracking system ensuring accurate and consistent tracking for Safety & Health, Environmental, Corporate Security.	Align business processes to Environmental, Health, Safety Management (EHSM) Incident Management "best practice" processes built into the tool, ensuring accurate tracking of incidents, employing learnings from corrective action plans and analytics to improve incident prevention, and ensure compliance for incident reporting. Supports incident prevention, which ensures a safe and productive workforce to complete customer work. Additionally supports CE's Planet goal through enhanced tracking and reporting for air quality, waste management, and sustainability, thereby making a positive contribution to the environment we share.	19-Aug	(0.27)	557,927	0	0	0	0	0	557,927	0
182	2018	Integrated Training (Dispatch Simulator)	BP Functionality	Software (Intangible)	Work Management	Business requires a dedicated training environment that integrates SAP, OMS, and Service Suite (FSS) that will be utilized by employees in DOET. The current QA Environment consists of SAP, OMS, and OMAR systems linked together which allows the user to be training on the entire process from start to finish in a more realistic setup. Duplication of the environment is a key factor on the delivery of our commitment to increase the number of trained and proficient employees working storm restoration efforts.	Business requires a dedicated training environment for each of the systems, OMS, SAP, and Service Suite (FSS) that will be integrated/communicate as setup in production. This will allow users (Dispatch employees and other employees supporting storm operation) to train on the entire process from start to finish. OMS upgrade included a dedicated training environment, SAP has an existing training environment and Service Suite (FSS) produced a dedicated Service Suite training environment as part of Release 1. This project will complete the integration between all the environments. The lack of a dedicated training environment for employees has hindered our ability to effectively run restoration efforts that provide the most effective results for our customers - i.e. CAIDI, 8-hour normal by, etc. Currently employees develop their skills through on-the-job training with no availability to have year-round training access, or to be able to practice in a simulated storm sessions.	18-Mar	3.31	68,277	0	0	31,000	26,000	0	11,277	0
183	2018	Manage Credits and Collections - Payment Plans	BP Functionality	Software (Intangible)	Customer Management	Streamline the standardization of the SPP (and WPP) payment plans, provide consistent eligibility criteria, enable enrollment consistently across channels and enable a multiple channel customer facing experience	• Improve system processing to ensure that SPP enrollment reflects the tariff and guidelines: o Restrict enrollment only to customers that qualify as low income o Establish income verification process – requires document submission process (customer produces proof of income or proof of assistance) o Improve tagging of low income customers (BP ID and Operands are not kept current) o Improved communication and notification of down payments, monthly amounts etc. o Expand enrollment capability to the Web • WPP (Winter Protection Program) should follow the same guidelines as SPP	18-Sep	(0.97)	385,895	0	0	0	0	0	385,895	0
184	2018	Manage IVR	BP Functionality	Software (Intangible)	Customer Management	Continuous improvements and enhancements to IVR system which would include menu refinements around options and restructuring of the menus to drive more optimal option and queue selections. These improvements will enable the optimization of the Contact Center Customer Experience Refresh platform.	Project scope will be centered around IVR menu selections/options refinement, appropriate choices for routing and queuing. The objective is to optimize the current platform with series of refinements. Value includes the ability to improve customer experience.	18-Oct	(0.98)	254,940	0	0	0	0	0	254,940	0
185	2018	Remote Application Delivery Strategy	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	This project will upgrade VDI and bring Citrix into VDI to eliminate the Citrix platform. Along with this, there is the intent to bring down the cost of each VDI. There are new technologies being implemented via Thin-App to allow for streaming applications.	Eliminating a platform that has redundant functionality. We will be gaining functionality with VMWare Thin-app giving us the capability to stream applications instead of having to push applications to the VDI's. This can reduce the size of the VDI footprint.	18-Dec	(0.98)	1,065,875	0	735,757	34,174	49,264	0	246,680	0
186	2018	Residential Joint Invoicing	BP Functionality	Software (Intangible)	Customer Management	This project involves enablement of SAP's standard consolidated billing functionality in order to provide a comprehensive view of a customer's usage in a single Bill. The 'One Bill' approach.	Supports increased convenience/satisfaction to the customer via delivery of a single bill rather than multiple. Generates cost savings to CE by decreasing printing, postage and payment processing costs. Estimated reduction of 2,400,000 bills annually	18-Oct	(1.03)	964,737	0	0	0	0	0	964,737	0

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
187	2018	Service Bench for VAPS	BP Functionality	Software (Intangible)	Customer Management	Enable better operational management, customer satisfaction and set the BU up for future expansion. Improve margin for the entire program which can be utilized at the corporate level to either offset utility customers rate increases or shareholder return	ServiceBench is a third party software platform specifically designed for service companies to utilize its modular software platform for effortless scheduling and dispatch, field work management, automated claims processing and real-time updates partnered with powerful analytics. This will be the replacement of SuperCOW as a new Service Mgmt System. This software performs scheduling, dispatching, field work management, automated claims processing, and data analytics. *manage resource availability *accept, dispatch, and monitor jobs *verify warranty authorizations *connect field reps with mobile app *verification of background screening *validation of trade licenses and certification *view parts availability, expedite ordering, track shipments *claims management *capture job site phots and customer signatures *provide field techs with directions, parts availability, job details, etc. *schedule repairs based on availability, location, products serviced *ability to send text, email, phone alerts to customer	18-Nov	2.93	1,115,010	0	0	283,923	707,465	0	123,621	0
188	2018	Telecom Expense Management (TEM) Strategic Innovation	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	Goal Achieve best in class TEM management and reporting: facilitate staff efficiencies, involve and inform CE leadership, reduce telecom spend across Consumers Energy Savings and Avoidance 'estimates' – * will work with select vendor during contract negotiations.	Identify an Enterprise Telecom Expense Management (TEM) solution, that will manage both fixed line and mobile resources along with inventory of radio and other communication equipment (mux, routers, switches, etc.).	18-Nov	1.45	145,675	0	0	0	0	0	145,675	0
189	2018	Wholesale Contractual Settlements	BP Functionality	Software (Intangible)	Energy Portfolio Planning	Wholesale Contractual Settlements currently uses a combination of Excel and Fortran programs to produce Remittance Statements to suppliers and NUGs (Non-Utility Generators). 70 contracts in total; 8 are Fortran which are 20+ years old and are for more complex contracts (more details, variables, scenarios and to the minute reads for the bill month). These contracts manage $960M annually. Consumers Energy has more PPAs than most utilities and each of these has varying parameters. Likely a phased solution first concentrating on replacing the Fortran programs and a second phase to replace and retire the Excel contract settlements. Replace Fortran and Excel programs and process; robust analytic capability and reporting; improve remittance process; integration with Managed Meter Solution (PCI EA and DW).	Create and implement a contractual settlements solution that will leverage the PCI EA and data warehouse for MISO settlements. Evaluate best platform for contracts which are currently in Excel and Fortran. Replace Fortran and Excel programs and process; robust analytic capability and reporting; improve remittance process; integration with Managed Meter Solution (PCI EA and DW). Functionality must accommodate many parameters specific to each contract; some very complex with a large number of parameters. Initial design includes implementing the Settlements Analyzer module from PCI and working with PCI to set up infrastructure that enables in-house development of invoices. If current solution fails, inability to accurately and timely settle supplier contracts which would result in legal issues and large interest payments (prime rate plus 1% of $75M/monthly contracts) and penalties for contract default if we do not settle by contract due dates.	18-Sep	(0.70)	212,411	0	0	111,485	47,600	0	53,326	0
190	**SUBTOTAL**	**2018 BP Functionality**								**21,181,036**	**586,601**	**1,495,743**	**5,442,148**	**4,048,320**	**0**	**9,120,042**	**488,180**
191	**TOTAL**	**2018**								**84,937,056**	**1,775,281**	**22,881,257**	**14,423,173**	**20,637,186**	**0**	**24,697,591**	**522,564**
192	2019	ARP - Collaboration Asset Refresh	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is for the refresh of the Company's Collaborative tools such as Telephony Systems, Video Conference Systems and Digital Whiteboard systems.	This project provides value by insuring the tools used by employees to communicate and conduct business activities are modern and reliable. Customers benefit as the business is more effective when communication systems are reliable and available.	19-Dec	(0.95)	1,125,973	291,000	291,000	197,880	232,800	0	113,293	0
193	2019	ARP - F5 Refresh	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project will refresh the company's F5 Load Balancing equipment. The F5 hardware was purchased in 2011 and the industry average refresh cycle is 5 years.	1) Refresh obsolete F5 equipment. 2) Determine required feature sets for new Load Balancer. 3) Implement new F5 according to industry best practices.	18-Jun	(0.96)	673,879	0	620,686	34,870	0	0	18,323	0

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194	2019	ARP - Field Device Asset Management (FDAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy field devices on a four-year refresh cycle. Field Devices typically last 4 years before we start having technical issues with the units. Completing the refresh will mitigate potential costs for hardware repairs, and allow Field Workers to complete their job tasks.	Field Workers require these rugged devices to complete their daily job tasks in support of our customers. Benefits of the ARP Field Device Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Reduced potential impact to our customers - Increased system performance such as speed, battery life, etc... - Increased CE employee opportunity to exceed expectations of our customers. - Less impact on future years for capital refresh requests, just pushing the issue if we delay	19-Dec	(1.09)	1,629,516	0	1,364,856	48,135	0	0	116,525	100,000
195	2019	ARP - Infoblox Refresh	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project will refresh the company's Infoblox (DNS, DHCP, and IP address management) equipment that was purchased in 2013. The industry average for Infoblox hardware refresh is 5 years.	1) Refresh obsolete Infoblox equipment. 2) Determine required feature sets for new equipment. 3) Implement new Infoblox according to industry best practices.	19-Jun	(0.98)	401,893	0	278,960	34,870	69,740	0	18,323	0
196	2019	ARP - Operational Technology Support	Upgrades & Replacements (Enterprise)	Network	Electric T&D, Gas T&D, Generation	Asset refresh project for infrastructure supported by Operational Technologies (OT). Replace assorted critical infrastructure due to obsolescence hardware as identified per 5 year budget planning/forecast. IT provides both hardware and labor funding. OT technologies covered by this ARP are Server, Workstation, Storage and Network devices including field communication devices that are managed by the OT department.	The requirement is to replace and upgrade the in scope items with current technologies. The project will replace functionality without necessarily doing a like-for-like replacement of the asset. For example, instead of replacing 20 servers with 20 servers, converged infrastructure will be implemented. Applications will have a lower risk of operational outages. Updated applications will benefit from better compatibility and increased capacity/performance and our maintenance costs will decrease as a result.	20-Dec	(1.04)	689,971	0	541,260	97,485	0	0	51,226	0
197	2019	ARP - Printer Asset Management (PAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy printers, plotters, and multi-function printing devices on a five-year refresh cycle for every department in the company. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older printers to complete their job tasks.	Employees require these printers/plotter to support their business efforts in support of our customers. Refreshing the equipment provides these benefits: - Reduces equipment failures reducing downtime for CE employee and meeting our customer expectation - Ensures printers can provide expected functionality with our print application meeting our customer expectations - Refreshed hardware allows Workstation software to function as designed reducing employee downtime and meeting customer expectation Customers are assured that our Call Centers and Dispatch centers have the required printing capabilities to meet our customer expectations	19-Dec	(1.05)	940,925	0	725,979	51,747	0	0	27,176	136,023
198	2019	ARP - Server	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	IT server infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT Infrastructure. This Server Asset Refresh Project (ARP) project will evaluate Computer Hardware with more than 5 years of continuous use and replace where appropriate.	The project will intelligently and systematically replace critical infrastructure before a system failure that would disrupt business operations. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers	19-Dec	(1.04)	1,229,542	0	828,040	263,199	0	0	138,304	0
199	2019	ARP - Storage	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	IT storage infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT infrastructure. This storage Asset Refresh Project (ARP) project will evaluate storage hardware with more than 5 years of continuous use and replace where appropriate.	This project is intended to address the ongoing refresh and storage growth needs within Information Technology regarding the data storage hardware. The project replaces hardware aged more than 5 years and provides incremental storage capacity where needed. The useful life of IT storage resources in a data center is 5 years. The project proactively replaces equipment after the useful life has expired to prevent unplanned outages and technology debt as well as ensuring capacity for growth. All Company business is performed based off IT systems. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers.	19-Dec	(1.06)	5,553,154	0	5,049,521	330,149	0	0	173,485	0

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200	2019	ARP - Wireless Network	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is to refresh targeted portions of the Company's various wireless networks including the 800 MHz Radio System Infrastructure. Cellular telephones can be used to fill small voids but are a great hindrance to productivity as they are a 1 to 1 conversation as opposed to a one to many conversation as supported by the 800Mhz Radio System. Call setup time is greatly increased with the use of cell phones. Most radio conversations to an entire group of employees is in the 5 second range, which is often faster than the time it takes just to place a telephone call to a single employee. A prolonged outage to this system, whether caused by force majeure or human error, would impact our ability to restore services, direct crews efficiently, and has a high probability of becoming a safety issue.	The scope of this project is extending the useful life of the Company owned radio systems. It's primary focus is on the 800 MHz radio system proper but also includes other systems, sub systems and components used within the Company such as transmitters, mobiles, control equipment and to a smaller part supporting physical plant equipment - tower lighting systems, HVAC units, emergency power systems. The 800 MHz radio network that has been built and maintained by Consumers Energy is the main means of communication to our field crews.. The project provides value by insuring reliable and real time communication between company crews and dispatch locations. This benefits the customer by enhancing life safety and reducing the amount of time it takes to restore service.	19-Dec	(0.98)	1,211,303	0	874,746	11,640	58,200	0	266,717	0
201	2019	ARP - Workstation Asset Management (WAM)	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	The project is in support of plans for IT to validate, procure and deploy desktops and laptop computers on a four-year refresh cycle for every department in the company. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older desktops or laptops to complete their job tasks.	Benefits of the APR Workstation Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Increased system performance such as speed, battery life, etc... - Less impact on future years for capital refresh requests, just pushing the issue if we delay - Improves opportunity for CE employees to exceed expectations of our customers.	19-Dec	(1.06)	4,649,473	0	4,126,679	145,673	0	0	76,547	300,574
202	2019	Data Center 2.0 - Disaster Recovery	Upgrades & Replacements (Enterprise)	New Computers / Hardware	Administrative & General (A&G) Support	This is a Program to - * Mitigate the current significant risks (location risks, capacity risks, technology risks) with the Consumers Energy IT Disaster Recovery capabilities, by Collocating to a Backup Recovery Center (BRC) at a vendor facility and by enabling Disaster Recovery (DR) capabilities at full Production capacity, for all systems per when business requirements dictate full capacity * Mitigate the risk to Project/ Development activities when a DR event is in progress (as the project/ development environments are currently needed to be commandeered in case of a disaster) * Provide an environment suitable to perform expanded DR testing * Build a 100% Production capacity for DR purposes at Switch. At the end of the migration to Switch, the compute capacity at Switch will be >= the compute capacity at Parnall. Some of the capacity will be on newly purchased hardware and some will be on hardware shifted from the Battle Creek Data Center. Currently, there are no plans to put compute for Production DR in the Cloud.	Mitigate risks to the Corporation in the event of a Disaster, by significantly enhancing the Disaster recovery capabilities, DR testing capabilities, and scalability constraints at the current data center locations. Scope includes - 1) Both IT & OT Data Centers 2) Migrate BRC to a vendor Colocation data center 3) Expand DR systems capacity to support 100% Production load requirements 4) Expand DR capabilities to all applications that are determined by the business partners as needing DR Scope excludes: 1) Relocating Parnall Data Center to a Colocation facility	20-Dec	(0.82)	15,750,082	453,309	8,299,037	2,301,414	3,486,990	0	1,209,332	0
203	2019	ESB Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	The Enterprise Service Bus (ESB) is an Enterprise Integration Platform initially implemented to support the Advanced Metering Infrastructure (AMI) Smart Energy Applications. It enables secure flow of data from Smart Meter head ends to SAP and other systems that process and store the data.	Project scope is the upgrade all components of the enterprise service bus, and refresh underlying infrastructure as needed. This project will provide the users with more current versions of software to better meet business requirements. Additionally the project will resolve all current issues with application versions and infrastructure thereby saving expenditure on maintenance extensions and remediating risk due to unsupported technologies running in production.	20-Dec	(0.91)	436,149	0	182,746	68,530	0	0	184,873	0
204	2019	Financial Consolidations	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	This project involves using SAP's Business Planning and Consolidation (BPC) module to provide regulatory reporting for GAAP (Generally Accepted Accounting Principles).	This project will configure SAP BPC module to support consolidations and enterprise reporting. * Ensure we continue to meet GAAP reporting requirements * Allow for productivity improvements with Excel integration. * Enables efficiencies to make changes to our hierarchies and consolidation components.	19-Nov	(0.94)	1,465,193	93,667	0	355,674	627,660	0	388,192	0
205	2019	Legal - Archiving Tool for Email, Chat, File shares, and SharePoint	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	This project will replace the existing archive tool with a new tool to support collection of emerging content types, provide increased reliability, ease of use, enhanced legal hold capabilities, and improved self-service for Legal to find relevant content.	Implement a tool that connects to various systems to capture information, assign retention policies, apply legal holds and purge data based on retention policy. Legal and end users must also be able to easily search for content in the archive system. Reduced eDiscovery internal search and collection times; decreased costs spent on external legal counsel; reduce the purchase of additional storage space.	19-Nov	(0.94)	1,673,760	560,265	747,020	93,377	186,755	0	86,343	0

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206	2019	Lotus Notes Application Migration & Retirement Wave 5	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Lotus Notes is an unsupported technology now at CE. Most of the 600+ LN applications can be moved to SharePoint, either from a direct move or customization. The applications are categorized into simple, medium, and complex. The migration is happening in 5 Phases or Waves and this is Wave 5.	This next phase will further enable capabilities on our current collaboration platform standard (SharePoint), while reducing the risk footprint of using an unsupported standard (Lotus Notes). SharePoint gives many new enhancements to these applications including collaboration, versioning of documents, security, and automated auditing. With the use of the K2 the users can also modify their own sites once migrated to better tailor them to their business needs.	19-Nov	(0.93)	891,473	0	0	437,265	186,070	0	268,139	0
207	2019	Redwood Cronacle Upgrade	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	The project will upgrade Redwood Cronacle batch job scheduling software to the latest version	Redwood Cronacle is the Company's batch Job Scheduler software that processes ~ 4000 scripts controlling critical business processes, including customer billing and payment, payroll and financial processing. The project will upgrade Cronacle to Version 9 which will help sustain business operations on a current and supported version.	19-Dec	(0.92)	839,596	69,740	209,220	261,525	139,480	0	159,631	0
208	2019	SharePoint 2016 Upgrade Project	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	This SharePoint Upgrade Project includes alignment with the Office365 cloud based hosting. This upgrade extends and enhances the existing SharePoint 2010 platform (which will become unsupported by MS in 2020 and extended support will NOT be available) by providing additional functionalities and enhanced user experience to the end user.	This project will create a new SharePoint 2016 environment and migrate all applications and data from the existing SharePoint 2010 environment. The SharePoint 2010 environment will be retired and decommissioned. Maintain system currency and security by moving to a supported version of SharePoint before SharePoint 2010 goes end of life (no support from Microsoft, no security patches) in 2020. Our customers will benefit as the data and applications in SharePoint will be on a supported platform. The newer version of SharePoint also supports browsing from mobile devices which can help us to server our customers and perform tasks more efficiently.	19-Jan	(1.02)	1,240,266	0	697,400	0	523,050	0	19,816	0
209	2019	Testing Center of Excellence (TCOE) Asset Lifecycle Management (ALM) Upgrade 2019	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Micro Focus ALM is our primary testing tool. It holds our test case repository enabling reuse of test cases across various initiatives. It contains test evidence, storing test results. It is used for test status reporting. It is used for defect management. This project upgrades Micro Focus ALM to the current version to ensure we stay on a supported version.	Micro Focus ALM is used to create a test case (test scripts) repository so that test cases can be reused across many application changes. Micro Focus ALM is also used to capture testing defects and manage the defect lifecycle through defect closure. Finally, Micro Focus ALM is used to track and manage test execution progress to ensure all tests are appropriately run. In short, Micro Focus ALM helps ensure quality and repeatable testing, which in turn helps ensure quality application changes. These benefits are for all applications including customer applications such as CRM, ivr, our CE.com web site and customer billing. Further, by doing the upgrade, we would continued to be on a version of the software that is supported by the vendor. If we have any issues, we'd be able to get support and fixes from the vendor.	19-Sep	(0.95)	133,536	0	0	27,432	70,437	0	11,167	24,500
210	2019	Testing Center of Excellence (TCOE) LoadRunner Upgrade 2019	Upgrades & Replacements (Enterprise)	Software (Intangible)	Administrative & General (A&G) Support	Micro Focus LoadRunner is our load testing tool. This tool is needed to ensure that application changes don't adversely impact performance. This project upgrades LoadRunner to ensure we stay on a supported version.	With LoadRunner, we can emulate load on an application such as having 300 users executing a total of 3,000 transactions an hour. This will help ensure that application changes can handle production loads before they are implemented so production is not adversely impacted. LoadRunner is used to conduct load tests on a variety of applications including customer applications such as CRM, ivr and our CE.com web site. Further, by doing the upgrade, we would continue to be on a version of the software that is supported by the vendor. If we have any issues, we'd be able to get support and fixes from the vendor.	19-Jul	(1.02)	34,870	0	27,370	0	0	0	0	7,500
211	2019	Time of Use Billing	Upgrades & Replacements (Enterprise)	Software (Intangible)	Customer Management	Consumers Energy will be filing a rate order with the MPSC in May 2018 requesting that all residential customers who are currently being billed using register index reads be switched to a new Time-Of-Use (TOU) interval based billing rate.	Expand the current TOU billing rate available to all electric residential customers. Provides for all electric customers to be able to take advantage of the Time of Use (TOU) rate during peak period times without having to sign up for the program, thereby allowing them to save on their energy bill during this period.	19-May	(0.94)	4,815,176	0	0	2,080,223	1,280,000	0	1,454,953	0

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212	2019	Wireless LAN Redesign	Upgrades & Replacements (Enterprise)	Network	Administrative & General (A&G) Support	This project is to address the aging Wireless Local Area Network (LAN) Infrastructure at Company locations throughout the State. The project will replace aging infrastructure with newer equipment that is capable of providing higher throughput for clients and more advanced feature sets than the current wireless LAN. This project will address the issue of coverage not being consistent at all Company locations. The current Wireless LAN was deployed mostly due to "organic growth". Many of the Company locations do not have the ubiquitous Wireless coverage that Business Partners have come to expect, this project would provide seamless coverage in the Company's office locations.	The project will collect survey data for all company locations and design wireless coverage based survey results. Deploy new Wireless Access Points to company locations. Verify coverage is as expected. The company will not be able to support new wireless devices that offer higher throughput and will not be able to support mobility at all company locations. Providing full Wireless coverage at all Company locations will enable higher productivity of our employees by providing connectivity beyond the desktop and better position the Company for the adoption of the "Internet of Things". Increasing the productivity of our employees will help us serve customers more efficiently.	19-Dec	(0.98)	566,820	87,300	180,420	20,952	182,166	0	45,982	50,000
213	**SUBTOTAL**	**2019 Upgrades & Replacements (Enterprise)**								**45,952,549**	**1,555,281**	**25,044,939**	**6,862,038**	**7,043,349**	**0**	**4,828,346**	**618,597**
214	2019	ED - ARP OSI HVD and LVD SCADA Upgrades	Upgrades & Replacements (Business Partner)	Software (Intangible)	Electric T&D, Gas T&D, Generation	The Electric Distribution (ED) Asset Refresh Project (ARP) upgrades OSII Supervisory Control and Data Acquisition (SCADA) application for High Voltage Distribution (HVD) and Low Voltage Distribution (LVD) systems. Biennial hardware refresh included.	The scope of this project is a software upgrade to the High Voltage Distribution (HVD) supervisory control and data acquisition (SCADA) software. The HVD SCADA is used to control generation and high transmission and distribution voltage circuits. Upgrading the HVD SCADA software will ensure that when problems occur, they are promptly addressed. Additionally, upgrades include enhancements and fixes to the core product that support reliability of electric delivery, ensuring that customers receiving the energy they need when they need it. Because the reliability of the entire distribution system is dependent on availability of the HVD system, staying relatively current with the solution provider upgrades is critical. If upgrades are delayed, additional full time resources will be required for 1 year to address upgrade complexities.	19-Dec	(0.98)	556,376	192,030	192,030	38,490	0	0	83,826	50,000
215	2019	Operations Application Currency	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	This effort is needed to ensure application currency for the Operations (Gas, Electric & Generation) Application Portfolio. The application upgrades have been prioritized based on business criticality and value, and this project will perform the routine upgrades/maintenance to ensure IT solutions supporting Operations business processes to deliver energy to our customers are stable and current.	The Operations Application Portfolio went through an assessment to evaluate application currency and technology obsolescence for this portfolio, prioritized needed upgrades based on business criticality and value, and this project was initiated to address priorities to ensure appropriate support and performance.	19-Dec	(0.94)	14,496	0	11,096	0	0	0	2,400	1,000
216	2019	PowerPlan Upgrade	Upgrades & Replacements (Business Partner)	Software (Intangible)	Administrative & General (A&G) Support	This project is to upgrade the functionality in PowerPlan to the latest version and properly address the new Leasing GAAP regulatory requirements for 2019	Upgrade the functionality in PowerPlan to handle the end of life, accommodate the new Leasing GAAP regulatory requirements effective 2019 and enable month-end close accuracy and automation through the financial close cockpit. Required to continue support and to comply with GAAP regulatory requirements.	19-Jan	(0.96)	220,424	90,968	0	91,565	0	0	22,891	15,000
217	**SUBTOTAL**	**2019 Upgrades & Replacements (Business Partner)**								**791,296**	**282,998**	**203,126**	**130,055**	**0**	**0**	**109,117**	**66,000**
218	2019	AccessNOW	Security	Software (Intangible)	Administrative & General (A&G) Support	Implementation of configurable Identity and Access Management for systems and best practices with enforced compliance. (Formerly Dell 1 Identity Manager)	This includes enterprise level foundation architecture, technology and end-2-end processes and controls. Processes will be fully automated user self-service and access lifecycle management. The project will deliver integrated and synced enterprise authoritative data.	20-Sep	(0.92)	958,124	0	0	136,956	464,862	0	356,306	0
219	2019	ARP - Cyber Security	Security	Network	Compliance & Risk Management	The objective for Cyber Security Asset Refresh project is to ensure continued vendor support of security technology deployed at the Company as well as reduce the risk of unplanned outages due to outdated hardware/software and appliances.	Replace end of life and obsolete systems; leading to less probability of equipment failures, software compatibility issues and business partner downtime.	19-Dec	(1.09)	523,800	0	523,800	0	0	0	0	0
220	2019	Fusion Center Project	Security	Network	Compliance & Risk Management	This project will support technology needs for the planned co-location for the Security Command Center and the Cyber Security Reponse Team. The (physical) Security Command Center and Cyber Security response teams will be co-located for more effective, holistic security operations and emergency response. The project will support the technology needs associated with the consolidated center.	This project would will entail finding a co-location for the Security Command Center and the Cyber Security Reponse Team. Along with combining the teams to one location we would also like to upgrade our current technology restraints, work place ergonomics, upgrade the HVAC (cooling) and have a better overall effectiveness of our security operations. This would also allow for possible integrated technology, logic driven software and future growth.	21-Jan	(0.95)	1,229,333	348,700	348,700	348,700	0	0	183,233	0

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221	2019	Mass Notification - Upgrades	Security	Software (Intangible)	Compliance & Risk Management	Provides the capability to communicate with desktop servers (send an alert out to desktops); and to activate a "Blue Light" at the service centers during an event (active shooter/lockdown, etc....) via the MNS system;	Implement/upgrade Siemens Fire-Panels at company locations. Similar to current capabilities used to announce "fire" events, the mass notification tool will allow notifications for other events requiring notification to building participants. This is directly tied to employee safety. Safety is increased by allowing better communications to employees during emergency situations.	Nov-19	(0.86)	55,097	0	0	34,870	0	0	20,227	0
222	2019	OT Security Architecture	Security	Network	Compliance & Risk Management	IT Information Security is taking responsibility for Cyber Security within various areas of the businesses' Operations Technology. The project will be used to implement a consistent security architecture across the Operational Technology landscape. Key scope includes the continuation of implementing the Consumers Energy OT security standard across the Generation fleet.	The project will be used to build a standard to house security requirements for Operational Technology architectures, identify controls that will have a high impact on cyber security at the plants, and implement consistent security architecture across the generation fleet. The lack of visibility into our operational sites increases risk of compromise. This project will build a standard to house security requirements for Operational Technology architectures, meet compliance requirements, identify controls that will have a high impact on cyber security at the plants, and implement consistent security architecture across the generation fleet.	19-Nov	(0.99)	954,930	0	0	625,989	0	0	328,941	0
223	2019	Physical Security Hardware Refresh	Security	Network	Compliance & Risk Management	This project will ensure continued compliance with Federal Energy Regulatory Commission requirements as it pertains to physical security assets. The scope includes enhancement and replacement of physical security assets, as part of the lifecycle replacement program. This includes security cameras, motion detectors, intrusion detection systems and card access systems. The Company has several thousand cameras and card readers in use.	Implement security assets at company sites for a variety of reasons; One leading factor is the company's responsibility to stay in compliance with Federal Energy Regulatory Commission (FERC) regulations. Projects can include, but are not limited to; implementing advance door systems at company buildings, implementing security cameras for monitoring capabilities, implementing gate and lock systems, etc. An integrated solution is efficient and allows for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster, more effective/consistent response to emergencies and non-emergencies thereby reducing the likelihood of impactful security events to our customers.	19-Dec	(1.07)	1,468,724	0	1,468,724	0	0	0	0	0
224	2019	Portable Security Cameras (Security Trailers)	Security		Compliance & Risk Management	Mobile Security Trailers that allow real time viewing of assets on project sites (Enhanced Infrastructure Replacement Project); high crime areas, and other applications as needed to protect our employees and assets.	Project would include the purchase of 7 new security pole cameras (to replace the old ones) and purchase 2 additional security pull camera trailers. These items are used for security surveillance at multiple locations (Company and Non-Company Locations). They are used as a visual deterrence and also record the area so we are aware of everything going on. The 2 security pull camera trailers we have are in high demand and are being used constantly, and we need more to help cover the need.	20-Jan	(0.93)	209,560	0	126,578	54,397	0	0	28,584	0
225	2019	Replace and Re-badge	Security	New Computers / Hardware	Compliance & Risk Management	Replace current outdated badge readers with new multi-class readers. Once multiclass readers are in place, we will rebadge company employees and contractors. (higher security and less vulnerable to cloning).	This project provides higher security and less vulnerability to cloning. Security Risk Avoidance/Mitigation. Because of this '99 technology our current badges can be cloned, with the new readers/badges we will be able to encrypt them , which will give us stronger security. Keeping our sites safe and secure provides reliability of service and business continuity for our customers.	20-Jan	(0.98)	523,176	174,001	278,960	46,028	0	0	24,187	0
226	2019	SAP Data Encryption	Security	Software (Intangible)	Administrative & General (A&G) Support	The project will implement Cyber Security requirements for encryption of Personal Identifying Information (PII) data "at rest" and "data in transit" in Company SAP data bases.	If we do not do this project, there is an increased risk of exposure of personal customer data if there is a breach. Currently this is an internal cyber security requirement, but there is also legislation in the works that will possibly make this mandatory. Alternative: Move to another SAP database technology which provides data encryption capability. This technology is being evaluated as part of the Planning phase of the project.	19-Dec	(1.00)	2,852,684	0	0	0	1,503,417	0	1,244,267	105,000

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227	2019	SAP Security	Security	Software (Intangible)	Compliance & Risk Management	The purpose of this project is to provide vulnerability scanning of SAP specific platforms. The project will include requirements gathering, vendor selection, product selection, tool design, configuration, and implementation. The benefit of this Project closes a gap as current information security vulnerability scanning tools do not provide the capabilities needed for new systems and solutions in our environment.	There is no functionality being delivered for this project in 2019. There is only a final payment associated with the project that will need to occur.	19-Dec	(0.97)	261,525	162,898	0	0	0	0	98,627	0
228	2019	Virtual Command Center Software	Security	Software (Intangible)	Compliance & Risk Management	Software that monitors news events, can be custom tailored to our specific geographic areas. News, Weather, Traffic, can be monitored. Security Command Center could send safety alerts out based off of data being monitored.	These new modules will allow us to use automated documents for compliance using auditing and/or assessment methods designed to evaluate our company sites. Allow us to do mass notification to all our company sites, incase of Threats of Violence (TOV), safety issues, weather issues, etc. More functionality to improve our current camera capabilities. Also the logic driven software will create faster technology in bringing up information for all our sites, making our Security Command Center more efficient.	20-Jan	(0.91)	174,932	76,017	24,409	45,331	0	0	29,175	0
229	**SUBTOTAL**	**2019 Security**								**9,211,885**	**761,616**	**2,771,171**	**1,292,271**	**1,968,279**	**0**	**2,313,547**	**105,000**
230	2019	800MHz Tower Connectivity Optimization	IT Service Delivery	Network	Administrative & General (A&G) Support	Telecommunication providers have announced the discontinuation of leased TDM (Time Division Multiplexing) services (i.e. T1's) by 2020. All radio tower sites will need to migrate to alternate technologies before this date.	Maximize radio system availability to improve reliability, employee/customer safety, gas leak response, and response time to customer outages. Migrate to a newer network technology before existing T1's are no longer supported.	19-Nov	(0.94)	1,123,249	0	0	10,930	873,775	0	148,543	90,000
231	2019	Nimbus Phase 5	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	Nimbus Phase 5 will be adding additional features to Nimbus, Consumers Energy's IT cloud infrastructure and application, including detailed automated reporting, support of network virtualization, and providing deeper integration into public cloud providers of our choice to support tertiary backup, big data and analytics support, and deployment of lower tier applications.	o Support network virtualization o Support big data and analytics o Provide tertiary backup o Support deployment of lower tier apps in the public cloud o Support automated horizontal scaling in the public cloud (storm boost) o Additional detailed reporting The project benefit is to further the company's ability to use public and private cloud resources in an on-demand and secure fashion, to increase the agility of IT, while reducing current backup costs and lowering risk in running applications in the cloud, keeping CE systems and customer data available and safe. The ability to provision or remove infrastructure as needed in the public cloud reduces cost & infrastructure support to only what is needed for a specific timeframe, as well as the ability to quickly provision when Disaster Recovery is required.	19-Dec	(0.95)	1,188,103	30,725	61,450	577,531	140,788	0	377,610	0
232	2019	RPA (Robotic Process Automation) Capability Enhancements	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	With an initial Robotic Process Automation (RPA) capability in place, this project is to expand the features and breadth of deployed use cases - further enabling the productivity and quality gains that result from this form of automation. These features can include, but are not limited to machine learning and natural language processing (such as in chat bots).	Benefits of Robotic Process Automation include the reduction of human errors, operational cost savings and/or avoidance, an increased workforce capacity for high value work in processes across the business, and quicker process execution to deliver outcomes - including those within the customer front/back-office domain. The specific benefit targets are contingent on which process candidates are automated to leverage this new functionality.	19-Dec	(0.94)	347,113	0	0	219,681	0	0	127,432	0
233	2019	SAP Archiving	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	With SAP being the company's primary Enterprise Resource Planning (ERP) platform for the integration of business processes, the daily system usage has resulted in massive amounts of data to be stored in SAP. Currently the size of the SAP ECC database alone is 23TB and is growing.	(1) Meet compliance requirements by purging any data that can become a liability as identified by CE legal team (2) Build an Archiving solution that allows the business to retrieve archived data with ease and in the form that is needed	19-Dec	(0.93)	668,615	0	20,922	305,461	104,610	0	237,621	0

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234	2019	TCOE Test Data & Environment Management	IT Service Delivery	Software (Intangible)	Administrative & General (A&G) Support	The purpose of this project is to implement the tool(s) and techniques to be able to periodically (e.g. annually) refresh our data in our SAP development and QA environments from production. It is a continuation of the work started in 2018. Our SAP test data is stale. Our SAP development environments have never been refreshed and our QA environments can go 5+ years without refreshes. This results in slower delivery since much time is needed to find and update data. This can also impact quality since testing is sometimes limited based on test data constraints especially in the development environments.	With improved SAP test data, our manual testing efforts will decrease, improving speed to deliver and reducing costs. Further, the quality of testing will improve and therefore the quality of the solutions will improve. This is true for all SAP applications and SAP interfacing applications including customer applications such as CRM, our CE.com web site and customer billing.	19-Jun	(0.94)	348,700	0	0	174,469	0	0	174,231	0
235	**SUBTOTAL**	**2019 IT Service Delivery**								**3,675,779**	**30,725**	**82,372**	**1,288,072**	**1,119,173**	**0**	**1,065,437**	**90,000**
236	2019	Enhancements - Corp	Enhancements	Software (Intangible)	Administrative & General (A&G) Support	Small software enhancement work efforts performed for Corporate and Shared Services business areas.	Each enhancement request has defined business value.	19-Dec	(0.90)	814,547	0	0	0	0	0	814,547	0
237	2019	Enhancements - Cust Exp-Ops	Enhancements	Software (Intangible)	Customer Management	Small software enhancement work efforts performed for Customer Experience business areas.	Each enhancement request has defined business value.	19-Dec	(0.98)	760,243	0	0	0	96,939	0	663,304	0
238	2019	Enhancements - Operations	Enhancements	Software (Intangible)	Customer Management	Small software enhancement work efforts performed for the ER business area.	Each enhancement request has defined business value.	19-Dec	(0.96)	360,309	0	0	0	0	0	360,309	0
239	2019	Enhancements - TEOS	Enhancements	Software (Intangible)	Administrative & General (A&G) Support	Small software enhancement work efforts performed for the TEOS business area.	Each enhancement request has defined business value including incremental cost savings, avoided costs, productivity improvements, operational efficiencies, waste and rework reduction, regulatory compliance, safety risk reduction, and improved customer response time.	19-Dec	(0.98)	428,453	0	0	0	0	0	428,453	0
240	2019	SAP Enhancement Pack Upgrade	Enhancements	Software (Intangible)	Administrative & General (A&G) Support	This project will complete a holistic maintenance upgrade to all SAP systems, including all SAP modules and the appropriate enhancement pack, support pack and other maintenance to be applied.	The scope of the project includes upgrading the SAP enhancement pack on all SAP systems. The application of the enhancement pack ensures system stability over known error scenarios. These enhancement packs do bring in new and updated business sets which are available for business process functionality enhancements and modifications. 1. Currency of SAP version reduces risk of system instability by implementing bug fixes released in every enhancement pack. 2. Currency of SAP version will implement new functionalities to increase efficiencies in serving our customers. 3. The key customer benefits are system stability, increased predictability, enhanced functionalities and updated interfaces	20-Apr	(0.81)	1,897,676	69,740	17,435	945,674	0	0	864,827	0
241	**SUBTOTAL**	**2019 Enhancements**								**4,261,229**	**69,740**	**17,435**	**945,674**	**96,939**	**0**	**3,131,441**	**0**
242	2019	Complex Billing Automation	BP Functionality	Software (Intangible)	Customer Management	The project will automate the manual process of setting up and billing Complex Billing customers, and will give those customers the ability to have the charges of all services (gas and electricity) within a single invoice.	Project scope will include -Automate fragmented processes to support complex billing - Update / revise complex account calculations based on rules while permitting customers to choose billing method / delivery time - Permit multiple accounts to be summarized. / Improved Customer experience by providing this customer segment currently receiving multiple bills to have one consolidated bill; reduced billing expenses due; allows customers to pay multiple bills with one invoice.	19-Dec	(0.94)	1,662,848	0	0	377,006	1,028,198	0	257,645	0
243	2019	Corporate Capital	BP Functionality	New Computers / Hardware	Administrative & General (A&G) Support	The capital is used to fund expenditures for senior officers, corporate officers, and corporate departments. In the past capital has been focused in the areas of IT equipment and related peripherals, video equipment for the Communications team, and facilities (furniture and officer/director moves). Small corporate expenditures that meet the spending threshold for capital, but not projects - No business case document	To meet the emergent, IT, and facility needs of the corporate area, and support the overall utility. Hardware nearing the end of lifecycle. Officers and new employees will be using new equipment to access their work to maximize productivity. Meeting the emergent IT needs of the corporate area ensures continuity of business processes. The facility office moves will increase the productivity of teams by grouping them together following a re-organization.	19-Dec	-	396,000	0	396,000	0	0	0	0	0

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244	2019	Credit and Collections	BP Functionality	Software (Intangible)	Customer Management	Investigate ways to leverage IT applications to support the lowering of uncollectible expense goals. Payments are uploaded and credit to a customers account automatically and efficiently. Examples are : SaaS (DebtNext) This would be to manage campaigns/channels etc. across the entire portfolio of Active, Final and Written-off. Technology Benefits: DebtNext - Cloud computing vs IT resources, customize system to meet business needs People Benefits - DebtNext - Real time decision support with reporting options provided Enhanced Communications - Easily understand, new communication channels (i.e. postcards) Process Benefits - DebtNext - would manage third party collections vendors and accounts placed with them. What we "need to do" not "what we have done" Financial Benefits - DebtNext - Reduce Cost and improve operations.	Technology Benefits: DebtNext - Cloud computing vs IT resources, customize system to meet business needs People Benefits - DebtNext - Real time decision support with reporting options provided Enhanced Communications - Easily understand, new communication channels (i.e. postcards) Process Benefits - DebtNext - would manage third party collections vendors and accounts placed with them. What we "need to do" not "what we have done" Financial Benefits - DebtNext - Reduce Cost and improve operations. Audit trail. / Reduce collectibles; Better visibly on age of inventory; ability to move accounts	19-Nov	5.00	65,736	0	0	33,541	0	0	32,195	0
245	2019	Customer Experience Improvements	BP Functionality	Software (Intangible)	Customer Management	New Outage Center (Phase 1 & 2): Redesign and facilitate customer outage reporting and provide restoration information delivery Move-In Move-out: Improve and expand customer move-in processes Billing & Payment Field Capability: Provide field ability to invoice and pay customers Content Personalization (incl rates experience): Provide customers increased awareness of rate options Gas Leak Response Tracker: Customer safety and response tracking information for gas leaks Integrated Rates Experience/Interval Data Portal Replacement: Replace unsupported interval third-party provider (SSN) Super User: Facilitate payment and mgmt of customers with multiple business accounts	New Outage Center (Phase 1 & 2): Location-specific report identification and restoration tracking; Move-In Move-out: Improve customer address matching and expand scope to business customers; Billing & Payment Field Capability: Provide field invoice and payment acceptance functionality; Content Personalization (incl rates experience): Provide rate information options and customer education; Gas Leak Response Tracker: Expedite customer safety awareness and resolution tracking for gas leaks; Integrated Rates Experience/Interval Data Portal Replacement: Enhance and migrate customer interval usage information Super User: Facilitated account management and payment for business customers	19-Dec	(0.67)	5,848,044	348,700	0	2,615,250	1,147,223	0	1,736,871	0
246	2019	ECM - ProjectWise Phase 2	BP Functionality	Software (Intangible)	Asset Management	ECM-ProjectWise Phase 2 will integrate the Engineering Content Management Phase 1 solution into SAP®, linking our enterprise work management system with ProjectWise and replacing WRAD File Manager (WFM) functionality. Phase 2 will expand to new user base in G&GAM, including DPE, Gas Customer Deliverability, System Engineers, and additional Project Controls teams, configuring the software and creating workflows to support business functionality for each area.	Project scope includes building an integration with the SAP document management system to ProjectWise, initiate ProjectWise workflows from SAP, link notifications generated by a maintenance plan to the asset folder in ProjectWise, and configure workflows for new user groups. The project will add value in the following ways: 1. Further mitigate risks with ineffective document management processes by providing complete, traceable, and verifiable records. 2. Increase in safety and compliance that is realized through a single source of truth for documentation of company assets. Create a single resource for construction and as-built drawings, eliminating the possibility of someone performing work based on an out of date print or schematic. 3. Create central repository for records that is readily accessible and easily searchable audits, investigations, and for end users performing engineering work modifying existing assets and/or designing new assets.	20-Dec	(0.94)	639,579	92,516	43,541	200,661	169,643	0	133,218	0

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247	2019	Enhanced Customer Data Analytics Platform	BP Functionality	Software (Intangible)	Customer Management	Create a comprehensive and analytical view of customers across various classes encompassing outages, billing history, payment history, customer usage and payment channel for the purpose of segmenting and providing improved customer experience.	Provide a single source for all of the customer interaction data within the utility. Provides analytics for modeling, and execution of one on one customer interactions. These analytics will provide insights into the various customer journeys and experiences allowing CE to determine opportunities to improve that experience across all channels. Here are the benefits to the customers of the project as it relates to website and contact center: Website: • We will deliver a more personalized experience that is expected to improve customer satisfaction. When we understand the attributes and preferences of our customers, we can tailor a personalized experience for each customer that logs in to their account on our website. The personalization may include: o Information about Energy Efficiency programs o Information on how to set up a payment arrangement or receive assistance paying their bills o Benefits of enrolling in our Demand Response programs o Other products and services we offer that are applicable to them Contact Center: • Allow agents to personalize the experience of the customer, with the expectation of improving customer satisfaction, by: o Providing the agents information about the customer's journey with Consumers Energy (billing, payments, website visits, outages, calls to contact center, and more) o Allow agents to recommend the "next best action" for the customer (may be a payment plan, enrolling in proactive alerts, participating in an Energy Efficiency program, etc.)	19-Nov	(0.97)	463,750	0	0	188,298	0	0	275,452	0
248	2019	Field Contractor Work Management Technology Enablement	BP Functionality	Software (Intangible)	Work Management	Contractor Technology Enablement provides the ability to electronically manage contractor work versus the current paper process. Contractors will be able to provide real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time.	Project scope includes the identification and implementation of an electronic Contractor Work Management solution for the groups identified by the Operations Gas and Electric sponsors. * Supports Customer On-Time Delivery Long Cycle Breakthrough goal by providing more electronic work orders to Contractors * Improves Customer Satisfaction and JD Power scores through efficiency in dispatching work and reporting on the progress via work order completions. * Easier movement of emergent work to contractors resulting in a reduction of CE overtime *Increased data accuracy resulting in decreased billing errors due to more complete work order information *Improved safety by tracking work status and employee status.	20-Mar	(0.55)	1,608,745	0	0	740,891	423,235	0	444,620	0
249	2019	Financial Planning Transformation - Phase 2	BP Functionality	Software (Intangible)	Administrative & General (A&G) Support	This is the second phase a technology roadmap to implement a company-wide suite of solutions to mature the company's operational planning activities. This phase supports monthly plan management while the first phase was limited to annual planning.	The scope of release 2 is focused on supporting and facilitating monthly plan management. The visibility of the linkages between financials and performance will allow us to better optimize our portfolio of work. This will ensure we are investing the right amount in the right areas, functions and assets thus reducing risk. This will reduce ad hoc reporting, reduce report-to-report reconciliation and enable automation of utility-wide plans down to the optimal level of detail.	19-Dec	(0.07)	385,681	0	0	244,090	0	0	141,591	0
250	2019	Fleet Telematics	BP Functionality	Software (Intangible)	Work Management	Fleet Telematics provides the ability to monitor the location and movement of fleet vehicles by Operations Work Management scheduling and dispatch. It also provides Fleet with vehicle utilization and health statistics data.	* Increase customer safety as the tool allows the dispatcher to select the appropriate field worker/crew to respond to emergency calls, by being able to select the closest in proximity to the emergency. * Increase Field Employee Safety with accurate location of field crews (via their vehicle location) prior to the energization of circuits * Reduction in Gas Emergency Response time through the identification of the closest Gas Field Crew to that emergency Reduction in Fleet vehicle maintenance costs by utilizing telematics information for predictive and preventative maintenance.	20-Nov	(0.37)	682,433	20,791	11,589	332,137	105,046	0	212,871	0
251	2019	Fleet Work Management Improvements	BP Functionality	Software (Intangible)	Work Management	Implement work order, parts lookup, and time entry processes into a single mechanics application ensuring efficiencies in the charging of time and parts to fleet work orders.	Scope will include a Feet Work Management system health measure scorecard and replacement of the SAP GUIXT custom development interfaces.	19-Oct	0.29	785,668	0	0	125,532	446,336	0	213,800	0

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Line No.	SPEND YEAR	PROJECT NAME	IT PROGRAM	FERC CATEGORY	UNITE CATEGORY	PROJECT DESCRIPTION	PROVIDED SCOPE / FUNCTIONALITY / BENEFIT	IMPLEMENT-ATION DATE	COST/BENEFIT RATIO	ELECTRIC PORTION SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	ENGINEERING COSTS-ELECTRIC	OVERHEAD & OTHER COSTS-ELECTRIC	CONTINGENCY COSTS-ELECTRIC
252	2019	Gen Ops Work Management Mobility	BP Functionality	New Computers / Hardware	Work Management	Provide Generation plant maintenance & operation personnel with durable, mobile devices and software, and improve wireless internet connection. Data retrieved and updated would include procedures, equipment statistics and work orders.	Replaces paper-dependent work management process with ability to access and update maintenance, operations and safety information. This includes mobile devices, software and wireless connection enhancement. Productivity: reduce need to return to kiosk/desk for updates; Quality: better updates when done right at time/place; Safety: current information at worksite vs. printed procedure/drawing; Employee Engagement: candidate pool looking for mobility in jobs.	20-Jun	(0.95)	336,884	34,870	174,350	83,688	0	0	43,976	0
253	2019	Incident and Risk Management	BP Functionality	Software (Intangible)	Compliance & Risk Management	Implement corporate-wide incident and risk management tracking system ensuring accurate and consistent tracking for Safety & Health, Environmental, Corporate Security.	Align business processes to Environmental, Health, Safety Management (EHSM) Incident Management "best practice" processes built into the tool, ensuring accurate tracking of incidents, employing learnings from corrective action plans and analytics to improve incident prevention, and ensure compliance for incident reporting. Supports incident prevention, which ensures a safe and productive workforce to complete customer work. Additionally supports CE's Planet goal through enhanced tracking and reporting for air quality, waste management, and sustainability, thereby making a positive contribution to the environment we share.	19-Aug	(0.27)	944,057	88,221	0	50,910	705,002	0	99,924	0
254	2019	SAP Work Order Overtime Allocation	BP Functionality	Software (Intangible)	Work Management	This project will enable the direct attribution of Overtime Costs to the impacted Work orders instead of spreading Overtime costs across all work orders and update the Capital Non-Asset program to meet Property Accounting Standards by utilizing activity types and additional Internal Orders (IOs) to better allocate costs to source programs.	This project provides Operation Program Managers better insight where we spend overtime on work; therefore, changing behaviors and practices to shift overtime spend. Additionally we would be able to identify those programs contributing more to overtime than others so measures can be taken to address chronic overtime occurrences with better planning or staffing decisions.	19-Nov	3.90	385,160	0	0	153,559	129,019	0	102,582	0
255	2019	Source to Pay	BP Functionality	Software (Intangible)	Supply Chain	Implement an extension of the SAP Ariba products (Contract Management and Spend Visibility) currently in use. Sourcing and procurement software modules from SAP Ariba will be used in streamlining the procurement processes, drive compliance and control while reducing costs and risks. This software will allow automated approval flows and integration with the various business networks.	SAP Ariba modules Supplier, Sourcing and Procurement will achieve sustainable cost savings throughout the procurement process with strategic sourcing software using SAP Ariba. The cloud-based solution will implement a closed-loop, automated process – for fast, flexible sourcing and significant savings. • Save time and facilitate repeatability by automating the RFX process • Capture best practice processes to ensure consistency and knowledge transfer • Get the best bid for 3rd party goods and services with electronic auctions • Establish contracts directly from the RFX or auction stage • Speed supplier proposal evaluation with scoring and optimization tools • Cloud-based software solution that aligns with CE's SAP ARIBA Contract Management and Spend Visibility additions • Single, web-based location to register and manage supplier information facilitate efficient customer organization collaboration Efficiencies gained through the source to pay efforts will see cost savings in materials and services which will benefit the rate paying customer.	20-Oct	5.00	530,580	0	0	84,301	382,873	0	63,406	0
256	**SUBTOTAL**	**2019 BP Functionality**								**14,735,166**	**585,098**	**625,480**	**5,229,863**	**4,536,573**	**0**	**3,758,151**	**0**
257	**TOTAL**	**2019**								**78,627,903**	**3,285,457**	**28,744,523**	**15,747,975**	**14,764,312**	**0**	**15,206,039**	**879,597**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Information Technology Highest Cost Top 25 Projects
Project Descriptions, Functionality, Alternatives, Timelines, Spending Plans, Benefits, Cost/Benefit Ratios, Implementation Dates
For the Projected Test Year 12 Months Ending December 31, 2019
($000)

Line No.	(a) Project	(b) Company IT Category	(c) Capital Costs - Approved Amounts	(d) O&M Savings	(e) Capital Savings	(f) Contingency - Capital	(g) Contingency O&M	(h) Project Description	(i) Alternatives Considered	(j) Project Scope/ Functionality	(k) Project Benefit	(l) Plan - Start Date	(m) Define Start - Date	(n) Execute - Start Date	(o) Close - Start Date	(p) Go - Live Date	(q) Cost Benefit Ratio
1	Data Center 2.0	Data Center 2.0	15,750,082	-	-	-	-	This is a Program to - * Mitigate the current significant risks (location risks, capacity risks, technology risks) with the Consumers Energy IT Disaster Recovery capabilities, by Collocating to a Backup Recovery Center (BRC) at a vendor facility and by enabling Disaster Recovery (DR) capabilities at full Production capacity, for all systems when business requirements dictate full capacity * Mitigate the risk to Project/Development activities when a DR event is in progress (as the project/development environments are currently needed to be commandeered in case of a disaster) * Provide an environment suitable to perform expanded DR testing (concurrently testing more applications and more end-to-end scenarios, than what is currently done) * Build a 100% Production capacity for DR purposes at Switch. At the end of the migration to Switch, the compute capacity at Switch will be >= the compute capacity at Parnall. Some of the capacity will be on newly purchased hardware and some will be on hardware shifted from the Battle Creek Data Center. Currently, there are no plans to put compute for Production DR in the Cloud.	The Company has performed an analysis of two primary alternatives to expand DR capabilities and address constraints/risks: 1) At the current BRC location, and 2) at a third party co-location facility. A co-location facility is a data center facility in which a business can rent space for servers and other computing hardware. Typically, a co-location vendor provides the building, cooling, power and physical security, while the business provides the servers, storage and other computing and networking equipment. Based on the analysis, the Company is planning to implement the third party co-location alternative for the BRC.	Scope includes - 1) Both IT & OT Data Centers 2) Migrate BRC to a vendor Colocation data center 3) Expand DR systems capacity to support 100% Production load requirements 4) Expand DR capabilities to all applications that are determined by the business partners as needing DR 5) Enable Cloud capabilities to migrate non-Production workloads to the Cloud, to allow for Production disaster recovery on non-Production infrastructure. Scope excludes: 1) Relocating Parnall Data Center to a Colocation facility	Mitigate risks to the Corporation in the event of a Disaster, by significantly enhancing the Disaster recovery capabilities, DR testing capabilities, and scalability constraints at the current data center locations.	Nov-17	Nov-17	Jul-18	Dec-20	Dec-20	(1.03)
2	Customer Experience Improvements	Customer Experience and Operations	5,848,044	-	-	-	-	Program has several components as described below: • New Outage Center (Phase 1 & 2): Redesign and facilitate customer outage reporting and provide restoration information delivery • Move-In Move-out: Improve and expand customer move-in processes • Billing & Payment Field Capability: Provide field ability to invoice and pay customers • Content Personalization (including rates experience): Provide customers increased awareness of rate options • Gas Leak Response Tracker: Customer safety and response tracking information for gas leaks • Integrated Rates Experience/Interval Data Portal Replacement: Replace unsupported interval third-party provider (Silver Spring Network) • Super User: Facilitate payment and management of customers with multiple business accounts	• Move-In Move-out: Do nothing to remedy failed address matches and business needs • Billing & Payment Field Capability: Do nothing to facilitate rapid invoice/payment capabilities • Content Personalization (including rates experience): Traditional customer outreach with limited penetration, applicability and reuse • Gas Leak Response Tracker: Do nothing to improve critical information communications and event tracking • Integrated Rates Experience/Interval Data Portal Replacement: Required to address vendor discontinuation; Use unsupported platform • Super User: Existing third-party solution (BillTrust) was reviewed: BillTrust can only address invoice groupings and is unable to consolidate customer management and invoices	• New Outage Center (Phase 1 & 2): Location-specific report identification and restoration tracking • Move-In Move-out: Improve customer address matching and expand scope to business customers • Billing & Payment Field Capability: Provide field invoice and payment acceptance functionality • Content Personalization (including rates experience): Provide rate information options and customer education • Gas Leak Response Tracker: Expedite customer safety awareness and resolution tracking for gas leaks • Integrated Rates Experience/Interval Data Portal Replacement: Enhance and migrate customer interval usage information • Super User: Facilitated account management and payment for business customers	$1.5M per year in O&M savings; 120,000 call reduction in 2018 and 200,000 call reduction in 2019; JD Powers score improvements: 15 pts in 2018, 8 pts in 2019	Jan-18	Mar-18	Jun-18	Dec-19	Nov-19	(0.67)
3	ARP - Storage	Asset Refresh Program	5,553,154	-	-	-	-	IT storage infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT infrastructure. This storage Asset Refresh Project (ARP) project will evaluate storage hardware with more than 5 years of continuous use and replace where appropriate.	In 2015 CE went through an RFP process for a converged infrastructure, where compute and storage resources are virtualized and shared across many applications and at that time multiple systems and vendors were compared. CE then selected the vBlock infrastructure as a standard through 2020. Doing nothing will cause some systems to become unavailable to the IT system End User as normal growth will exceed the storage resources currently available.	This project is intended to address the ongoing refresh and storage growth needs within Information Technology regarding the data storage hardware. The project replaces hardware aged more than 5 years and provides incremental storage capacity where needed. The useful life of IT storage resources in a data center is 5 years.	The project proactively replaces equipment after the useful life has expired to prevent unplanned outages and technology debt as well as ensuring capacity for growth. All Company business is performed based off IT systems. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers	NA	NA	NA	NA	Dec-19	(1.06)
4	Time of Use Billing Rate Expansion	Customer Experience and Operations	4,815,176	-	-	-	-	Consumers Energy plans to file a rate order with the MPSC in May 2018 requesting that all residential customers who are currently being billed using register index reads be switched to a new Time-Of-Use (TOU) interval based billing rate.	Switch customers currently on a indexed read rate (RS1000) to a current time of use rate (RS1007); however the current time of use rates have a three tier structure rate with summer rates and winter rates and the proposal is to move these customers to a 2 tier On peak/Off peak pricing structure for the summer months, and a single tier for the winter months.	Create a new residential Time of Use period rate to replace existing rate RS_1000 Configure a new 'Peak Power Savers' credit billing provision for customers during billing months June – September.	Provides for all electric customers to be able to take advantage of the Time of Use (TOU) rate during peak period times without having to sign up for the program, thereby allowing them to save on their energy bill during this period.	May-18	Jun-18	Aug-18	May-19	Mar-19	(0.94)
5	ARP - Workstation Asset Management (WAM)	Asset Refresh Program	4,649,473	-	-	$0.301	-	The project is in support of plans for IT to validate, procure and deploy desktops and laptop computers on a four-year refresh cycle for every department in the company. Workstations typically last 4 years before we start having technical issues with the units. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older desktops or laptops to complete their job tasks.	If no funding was available we could use a limited supply of 4 year old units for some new hires (reduced system performance) but would still need some funding for the purchase of new hire workstations and contractor workstations in 2019. The remaining dollars for Work Station Asset Management would need to be added to the following year budget (approx. 4M) and would double the purchasing and work effort for 2020.	The project scope is to support plans for IT to validate, procure and deploy desktops and laptop computers on a four-year refresh cycle for every department in the company. The workstation refresh objectives are to reduce hardware repairs, reduce potential employee downtime, and increase system performance for our employees in support of our customers.	Benefits of the ARP Workstation Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Increased system performance such as speed, battery life, etc... - Less impact on future years for capital refresh requests, just pushing the issue if we delay - Improves opportunity for CE employees to exceed expectations of our customers.	NA	NA	NA	NA	Dec-19	(1.08)
6	SAP Data Encryption	Security	2,852,684	-	-	$0.105	-	The project will implement Cyber Security requirements for encryption of Personal Identifying Information (PII) data "at rest" and "data in transit" in Company SAP data bases.	If we do not do this project, there is an increased risk of exposure of personal customer data if there is a breach. Currently this is an internal cyber security requirement, but there is also legislation in the works that will possibly make this mandatory. An alternative would be to move to another SAP database technology which provides data encryption capability. This technology is being evaluated as part of the Planning phase of the project.	The Company must implement and maintain reasonable data security and privacy procedures and practices appropriate to the sensitive nature of the information. All PII collected, used, retained, disclosed, and disposed by the Company is within the scope of this standard. Such information includes, but is not limited to, PII of: Customers, Employees, Contractors, Directors and Shareholders. The data requirements to be encrypted is just the data at rest, which is the data in the database.	1. Reduction in risk to our customer of their data being compromised if there is a breach. 2. Reduction in risk to Consumers Energy reputation 2. Compliance with Information Security encryption for SAP Data at rest and in transit. 3. Reduction of liability due to personal data breaches. 4. Compliance with potential future legislation in progress currently that is going to make this mandatory.	Jan-18	Aug-18	Feb-19	Dec-19	Nov-19	(1.00)

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7	SAP Enhancement Pack Upgrade	Asset Refresh Program	1,897,676	$0.176	-		-	This project will complete a holistic maintenance upgrade to all SAP systems, including all SAP modules and the appropriate enhancement pack, support pack and other maintenance to be applied.	We do have an option to do nothing. If we do nothing, it would put us behind on enhancement packs and increase the risk to system stability since enhancement pack releases include bug fixes for reported incidents. The every 2 year enhancement pack upgrade cycle ensures we stay ahead of known issues and hence improve system stability. Not keeping up with enhancement packs impacts our customers as we cannot leverage improvements and enhancements to serve our customers more efficiently.	The scope of the project includes upgrading the SAP enhancement pack on all SAP systems. The application of the enhancement pack ensures system stability over known error scenarios. These enhancement packs do bring in new and updated business sets which are available for business process functionality enhancements and modifications.	1. Currency of SAP version reduces risk of system instability by implementing bug fixes released in every enhancement pack. 2. Currency of SAP version will implement new functionalities to increase efficiencies in serving our customers. 3. The key customer benefits are system stability, increased predictability, enhanced functionalities and updated interfaces	Jan-19	Apr-19	Aug-19	Apr-20	Mar-20	(0.81)
8	Legal - Archiving Tool for Email, Chat, Fileshares, and SharePoint	Corporate and Enterprise	1,673,760	-	-		-	This project will replace the existing archive tool with a new tool to support collection of emerging content types, provide increased reliability, ease of use, enhanced legal hold capabilities, and improved self-service for Legal to find relevant content.	For the past few years, CE IT staff have spent significant manual work to maintain the integrity of the solution. If we do nothing, Legal will need to hire additional staff.	Implement a tool that connects to various systems to capture information, assign retention policies, apply legal holds and purge data based on retention policy. Legal and end users must also be able to easily search for content in the archive system.	Reduced eDiscovery internal search and collection times; reduce the purchase of additional storage space.	Feb-19	May-19	Jul-19	Nov-19	Nov-19	(0.94)
9	Complex Billing Automation	Customer Experience and Operations	1,662,848	-	-	-	-	The purpose of the Complex Billing automation project is to reduce manual intervention and decrease risk of error on large customer and specialty billing accounts. Complex billing encompasses, but is not limited to, all primary rates that require MV90 billing, large commercial and industrial rates, unique customer specific billing solutions (i.e., MSU, BioDigestor, some self-generators), and customer programs such as net metering.	The process to set up and bill large Commercial customers is a very manual process. The alternative is to maintain the status quo and continue to leverage employees to manually set up, bill, and monitor the billing of these customers. Additionally, it doesn't allow for CE to meet the customer's demands to provide a single invoice for all services.	Project scope will include: Automate fragmented processes to support complex billing Update / revise complex account calculations based on rules while permitting customers to choose a billing method and delivery time Permit multiple accounts to be summarized Address Net meter billing, Collective accounts, Gas Transportation accounts and unmetered billing accounts	Improving the process of setting up and billing this customer segment by automating the process; Improved Customer experience by providing this customer segment currently receiving multiple bills to have one consolidated bill; Allows customers to pay multiple bills with one invoice.	Jan-19	Mar-19	May-19	Dec-19	Dec-19	(0.95)
10	ARP - Field Device Asset Management (FDAM)	Asset Refresh Program	1,629,516	-	-	$0.100	-	The project is in support of plans for IT to validate, procure and deploy field devices on a four-year refresh cycle. Field Devices typically last 4 years before we start having technical issues with the units. Completing the refresh will mitigate potential costs for hardware repairs, and allow Field Workers to complete their job tasks.	If no funding was available we could use a very limited supply of 4 year old units for some new hires (reduced system performance) but would still need some funding for the purchase of new hire Field Devices in 2019. The remaining dollars for Field Device Asset Management would need to be added to the 2020 budget and would double the purchasing and work effort. Field Devices are extremely important to our service workers in the field and could cause potential slow response and/or safety concerns if equipment begins failing at a high rate.	The project scope is to support plans for IT to validate, procure and deploy field devices on a four-year refresh cycle. The field device refresh project objectives are to reduce hardware repairs, improve system performance, and reduce potential downtime for our field worker, and impact to our customers.	Field Workers require these rugged devices to complete their daily job tasks in support of our customers. Benefits of the ARP Field Device Refresh Program: - Reduced equipment failures - Increased CE Employee Up Time, Productivity - Reduced software compatibility issues - Reduced potential impact to our customers - Increased system performance such as speed, battery life, etc... - Increased CE employee opportunity to exceed expectations of our customers. - Less impact on future years for capital refresh requests, just pushing the issue if we delay	NA	NA	NA	NA	Dec-19	(1.09)
11	Field Contractor Work Management Technology Enablement	Generation and Field Operations	1,608,745	$0.400	-	-	-	Field Contractor Work Management Technology Enablement provides the ability to electronically manage contractor work versus the current paper process. This project will enable Electric Contractors the ability to provide real time updates to work order information, receive emergent work orders, provide increased data accuracy on complete work orders resulting in improved schedule predictability for customers.	The alternative is to continue with the current paper-based process for Contractors.	Project scope includes the identification and implementation of an electronic Contractor Work Management solution for the groups identified by the Operations Electric sponsors.	* Improves Customer Satisfaction and JD Power scores through efficiency in dispatching work and reporting on the progress via work order completions; improved schedule predictability of utility services provided to customers so that they can keep their construction and business plans on track * Easier movement of emergent work to contractors resulting in a reduction of CE overtime *Increased data accuracy resulting in decreased billing errors due to more complete work order information *Improved safety by tracking work status and employee status.	Jan-19	Feb-19	Jul-19	Mar-20	Mar-20	(0.55)
12	Physical Security Hardware Refresh	Security	1,468,724	-	-		-	This project will ensure continued compliance with Federal Energy Regulatory Commission requirements as it pertains to physical security assets. The scope includes enhancement and replacement of physical security assets, as part of the lifecycle replacement program. This includes security cameras, motion detectors, intrusion detection systems and card access systems. The Company has several thousand cameras and card readers in use.	The alternative is to not do this work and assume the risk that the Company falls short of Federal Energy Regulatory Compliance requirements which could result in the increase of potential security vulnerabilities, associated penalties and reputational damage.	Implement security assets at company sites for a variety of reasons; One leading factor is the company's responsibility to stay in compliance with Federal Energy Regulatory Commission (FERC) regulations. Projects can include, but are not limited to; implementing advance door systems at company buildings, implementing security cameras for monitoring capabilities, implementing gate and lock systems, etc.	An integrated solution is efficient and allows for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster, more effective/consistent response to emergencies and non-emergencies thereby reducing the likelihood of impactful security events to our customers.	NA	NA	NA	NA	Dec-19	(1.07)
13	Financial Consolidations	Corporate and Enterprise	1,465,193	-	-	-	-	This project involves using SAP's Business Planning and Consolidation (BPC) module to provide regulatory reporting for GAAP (Generally Accepted Accounting Principles).	Alternative: We continue using the current SAP EC-CS (Enterprise Controlling – Consolidation System) module which has a support end of life in 2020 which may then impact filing of 10-Q or 10K statements.	This project will configure SAP BPC module to support consolidations and enterprise reporting.	* Ensure we continue to meet GAAP reporting requirements * Allow for productivity improvements with Excel integration. * Enables efficiencies to make changes to our hierarchies and consolidation components.	Feb-19	Apr-19	Jun-19	Oct-19	Oct-19	(0.94)
14	SharePoint 2016 Upgrade Project	Asset Refresh Program	1,240,266	-	-		-	This upgrade extends and enhances the existing SharePoint 2010 platform (which will become unsupported by MS in 2020 and extended support will NOT be available) by providing additional functionalities and enhanced user experience to the end user. This SharePoint Upgrade Project includes alignment with the Office365 cloud based hosting.	No other alternatives are available as the applications and data in the current SharePoint system are specific to Microsoft's proprietary ecosystem. Risk: SharePoint 2010, the version that is currently running at Consumers Energy, went end of Mainstream support from Microsoft on 10/13/2015. Only critical patches are being provided by Microsoft, no enhancements or functionality will be added going forward. The SharePoint 2010 product will be end of life (unsupportable without significant cost) on 10/13/2020.	This project will create a new SharePoint 2016 environment and migrate all applications and data from the existing SharePoint 2010 environment. The SharePoint 2010 environment will be retired and decommissioned.	Maintain system currency and security by moving to a supported version of SharePoint before SharePoint 2010 goes end of life (no support from Microsoft, no security patches) in 2020. Our customers will benefit as the data and applications in SharePoint will be on a supported platform. The newer version of SharePoint also supports browsing from mobile devices which can help us to serve our customers and perform tasks more efficiently.	Jan-19	Mar-19	May-19	Dec-19	Dec-19	(1.02)
15	ARP - Server	Asset Refresh Program	1,229,542	-	-	-	-	IT server infrastructure generally becomes less reliable after 5 years, jeopardizing the stability of our business' critical applications running on top of our IT infrastructure. This Server Asset Refresh Project (ARP) project will evaluate Computer Hardware with more than 5 years of continuous use and replace where appropriate.	In 2015 CE went through an RFP process for a converged infrastructure, where compute and storage resources are virtualized and shared across many applications and at that time multiple systems and vendors were compared. CE then selected the vBlock infrastructure as a standard through 2020. Doing nothing will cause some systems to become unavailable to the IT system End User as normal growth will exceed the compute resources currently available.	The project proactively replaces server equipment after the useful life has expired to prevent unplanned outages and technology debt as well as ensuring capacity for growth. The useful life of IT compute resources in a data center is 5 years.	The project will intelligently and systematically replace critical infrastructure before a system failure that would disrupt business operations. Keeping IT systems current and well maintained keeps all of the applications available to Consumers Energy Employees for the purpose of serving our customers	NA	NA	NA	NA	Dec-19	(1.05)

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16	Fusion Center Project	Security	1,229,333	-	-		-	This project will support technology needs for the planned co-location for the Security Command Center and the Cyber Security Response Team. The (physical) Security Command Center and Cyber Security response teams will be co-located for more effective, holistic security operations and emergency response. The project will support the technology needs associated with the consolidated center.	The alternative to this project is to continue to run a separate Security Command Center for Physical security incident response and a separate Cyber Security Incident Response Center. The two Centers would also continue to run separate, non-integrated systems and tools, potentially missing key security vulnerabilities and risks.	This project will entail finding a co-location for the Security Command Center and the Cyber Security Response Team. Along with combining the teams to one location we would also like to upgrade our current technology restraints, work place ergonomics, upgrade the HVAC (cooling) and have a better overall effectiveness of our security operations. This would also allow for possible integrated technology, logic driven software and future growth.	The (physical) Security Command Center and Cyber Security response teams will be co-located and will begin integrating processes and technologies for more effective, holistic security operations and emergency response, thereby reducing the likelihood of impactful security events to our customers.	Jan-19	May-19	Oct-20	Jan-21	Jan-21	(0.95)
17	ARP - Wireless Network	Asset Refresh Program	1,211,303	-	-	-	-	This project is to refresh targeted portions of the Company's various wireless networks including the 800 MHz Radio System Infrastructure It will ensure the reliable operation of the equipment necessary to communicate to our field workers, especially during storm restoration. Cellular telephones can be used to fill small voids but are a great hindrance to productivity as they are a 1 to 1 conversation as opposed to a one to many conversation as supported by the 800Mhz Radio System. Call setup time is greatly increased with the use of cell phones. Most radio conversations to an entire group of employees is in the 5 second range, which is often faster than the time it takes just to place a telephone call to a single employee. A prolonged outage to this system, whether caused by force majeure or human error, would impact our ability to restore services, direct crews efficiently, and has a high probability of becoming a safety issue.	Alternatives would be to not refresh items required for regulatory compliance(*). We would also not refresh 25 year old Radios thus extending the life of unsupported hardware. This increases the risk of a failure resulting in not being able to communicate with employees during critical events. *FAA – Obstruction Marking and Lighting per the FAA Advisory Circular 70/7460-1L . Ensuring they are operational per type of system required at each tower, e.g.; single/multiple beacons, side lights, red/white lights and paint requirements. *FCC – Fixed transmitters and mobile/portable radios per FCC Part 90 rules. Ensuring they meet licensing requirements e.g.; power output, emissions mask, frequency deviation, modulation.	The scope of this project is extending the useful life of the Company owned radio systems. Its primary focus is on the 800 MHz radio system proper but also includes other systems, sub systems and components used within the Company such as transmitters, mobiles, control equipment and to a smaller part supporting physical plant equipment - tower lighting systems, HVAC units, emergency power systems. The 800 MHz radio network that has been built and maintained by Consumers Energy is the main means of communication to our field crews. There are 67 towers with minimal coverage overlap which communicate via carrier lines to 3 interconnected head end units.	The project provides value by insuring reliable and real time communication between company crews and dispatch locations. This benefits the customer by enhancing life safety and reducing the amount of time it takes to restore service.	NA	NA	NA	NA	Dec-19	(0.98)
18	Nimbus Phase 5	Asset Refresh Program	1,188,103	-	-		-	Nimbus Phase 5 will be adding additional features to Nimbus, Consumers Energy's IT cloud infrastructure and application, including detailed automated reporting, support of network virtualization, and providing deeper integration into public cloud providers of our choice to support tertiary backup, big data and analytics support, and deployment of lower tier applications.	CE IT infrastructure would need to be built manually. Currently, manual builds take approximately 19 business days, where Nimbus automated builds take approx. 1-4 hours. This extra time is waste. As well, the quality of manual builds is not consistent and often results in necessary rework - which is also waste.	Support network virtualization Support big data and analytics Provide tertiary backup Support deployment of lower tier apps in the public cloud Support automated horizontal scaling in the public cloud (storm boost) Additional detailed reporting	The project benefit is to further the company's ability to use public and private cloud resources in an on-demand and secure fashion, to increase the agility of IT, while reducing current backup costs and lowering risk in running applications in the cloud, keeping CE systems and customer data available and safe. The ability to provision or remove infrastructure as needed in the public cloud reduces cost & infrastructure support to only what is needed for a specific timeframe, as well as the ability to quickly provision when Disaster Recovery is required.	Jan-19	Mar-19	May-19	Dec-19	Dec-19	(0.95)
19	ARP - Collaboration Asset Refresh	Asset Refresh Program	1,125,973	-	-	-	-	This project is for the refresh of the Company's Collaborative tools such as Telephony Systems, Video Conference Systems and Digital Whiteboard systems.	Alternative is to do nothing and assume the risk of an extended outage due to the equipment end of life. End of life means that the manufacturer no longer supports the equipment and there is no guarantee that repairs could be made in a timely fashion, if at all.	This project is for the refresh of the company's collaborative tools such at telephony systems, video conference systems, and digital whiteboard systems.	This project provides value by insuring the tools used by employees to communicate and conduct business activities are modern and reliable. Customers benefit as the business is more effective when communication systems are reliable and available.	NA	NA	NA	NA	Dec-19	(0.98)
20	800MHz Tower Connectivity Optimization	Asset Refresh Program	1,123,249	-	-	$0.090	-	Telecommunication providers have announced the discontinuation of leased Timed Division Multi-plexing (TDM) services (i.e. T1's) by 2020. All radio tower sites will need to migrate to alternate technologies before this date. This project is purely replacing/upgrading the back haul circuits that connect the remote tower sites to the head end electronics. The ARP Wireless project is largely refreshing the radio equipment itself (transmitters, mobiles, control equipment) and to a smaller part supporting physical plant equipment (tower lighting systems, HVAC units, emergency power systems).	Alternatives considered were 1.) Do nothing and continue escalation of chronic circuit outages to the carriers. 2.) Install Consumers owned fiber or 3.) Install point to point microwave. These alternatives were not selected due to being undesirable from a reliability perspective (option 1) or being too costly (option 2 and 3).	Migrate to a newer network technology before existing T1's are no longer supported.	Maximize radio system availability to improve reliability, employee/customer safety, gas leak response, and response time to customer outages.	NA	NA	NA	NA	Dec-19	(0.95)
21	AccessNOW	Security	958,124	$0.104	-	-	-	The project is chartered for implementation of a configurable identity and access management toolset. This technology is called one identity manager and will be known as AccessNOW in our environment. The project's primary objectives are to replace the existing access provisioning system and to automate provisioning processes that are currently manual. The tool will consist of a web portal for internal end users to make their system access requests automated processes to fulfill these requests. There will be multiple project implementations to achieve these objectives.	Manual processes were considered, but too costly and inefficient. Continuing to use existing Lotus Notes database - End of life technology, limited functionality, desire to remove Lotus Notes from CE. Alternate technology solutions considered were Service Now which we determined could not handle the automation that the One Identity manager toolset could provide.	This includes enterprise level foundation architecture, technology and end-2-end processes and controls. Processes will continue to be fully automated, user self-service and access lifecycle management. The project will deliver integrated and synced enterprise authoritative data.	The project work conducted for AccessNow in 2019 will deliver automated processes and security risk mitigation of human error on SoX related systems. This will reduce compliance findings and increase efficiency, which in turn reduces potential operating costs for the company that eventually are passed to our customer.	Jan-19	Mar-19	Apr-19	Jun-19	Jun-19	(0.93)
22	OT Security Architecture	Security	954,930	-	-		-	IT Information Security is taking responsibility for Cyber Security within various areas of the businesses' Operations Technology. The project will be used to implement a consistent security architecture across the Operational Technology landscape. Key scope includes the continuation of implementing the Consumers Energy OT security standard across the Generation fleet.	The alternative is to continue to operate the Operational Technology systems outside of the corporate security architecture. This would result in the company assuming all risks associated with limited visibility into the security posture of the generation fleet, with increased potential for security vulnerabilities, associated penalties and reputational damage.	The project will be used to build a standard to house security requirements for Operational Technology architectures, identify controls that will have a high impact on cyber security at the plants, and implement consistent security architecture across the generation fleet.	The lack of visibility into our operational sites increases risk of compromise. This project will build a standard to house security requirements for Operational Technology architectures, meet compliance requirements, identify controls that will have a high impact on cyber security at the plants, and implement consistent security architecture across the generation fleet.	NA	NA	NA	NA	Nov-19	(0.99)

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23	Incident and Risk Management	Engineering	944,057	$0.525	-		-	Implement corporate-wide incident and risk management tracking system ensuring accurate and consistent tracking for Safety & Health, Environmental, Corporate Security.	There is no one tool or process for tracking incident and risk management tracking. Safety & Health, Environmental, Corporate Security would continue to track separately with Excel and SharePoint, follow inconsistent processes, with inability to centrally track and analyze incidents.	Implementation of the standard business processes and incident types for Environmental, Health, Safety Management (EHSM) Incident Management, Near Misses and Safety Observations. Incident investigation, incident risk assessment and task management to organize incident management overall including incident prevention. Corrective action tracking, workflows and reminders	Align business processes to Environmental, Health, Safety Management (EHSM) Incident Management "best practice" processes built into the tool, ensuring accurate tracking of incidents, employing learnings from corrective action plans and analytics to improve incident prevention, and ensure compliance for incident reporting. Supports incident prevention, which ensures a safe and productive workforce to complete customer work. Additionally supports CE's Planet goal through enhanced tracking and reporting for air quality, waste management, and sustainability, thereby making a positive contribution to the environment we share.	Aug-18	Sep-18	Nov-18	Aug-19	Aug-19	(0.27)
24	ARP - Printer Asset Management (PAM)	Asset Refresh Program	940,925	-	-	$0.136	-	The project is in support of plans for IT to validate, procure and deploy printers, plotters, and multi-function printing devices on a five-year refresh cycle for every department in the company. Not completing the refresh will push the need for more capital dollars into future years. It will also increase costs for hardware repairs and potentially not allow CE employees with older printers to complete their job tasks.	CE could continue to delay the printer refresh for some lower use printers but we will continue to have older printers that will not function with our managed print applications causing reduced functionality or non-functional printers. CE has delayed some printer refresh in the past two years based on equipment usage and repair data. This printer refresh delay has caused issues with our managed print applications. The printers lose functionality when we do not refresh on a timely basis. An example is some of the units we did not refresh over the past few years cannot use our scan and fax functionality until the printers are refreshed. We also just push the funding requirement to future years increasing our capital requests.	The project is in support of plans for IT to validate, procure and deploy printers, plotters, and multi-function printing devices on a five-year refresh cycle for every department in the company. The functionality of the printers is maintained or increased when we refresh the printers. The refresh will ensure printers can function with our managed print applications allowing CE employees to meet our customer expectations and meet our Green initiatives.	Employees require these printers/plotter to support their business efforts in support of our customers. Refreshing the equipment provides these benefits: - Reduces equipment failures reducing downtime for CE employee and meeting our customer expectation - Ensures printers can provide expected functionality with our print application meeting our customer expectations - Refreshed hardware allows Workstation software to function as designed reducing employee downtime and meeting customer expectation Customers are assured that our Call Centers and Dispatch centers have the required printing capabilities to meet our customer expectations	NA	NA	NA	NA	Dec-19	(1.07)
25	Lotus Notes Application Migration & Retirement Wave 5	Asset Refresh Program	891,473	-	-		-	Lotus Notes is an unsupported technology now at CE. Most of the 600+ LN applications can be moved to SharePoint, either from a direct move or customization. The applications are categorized into simple, medium, and complex. The migration is happening in 5 Phases or Waves and this is Wave 5.	We previously evaluated an option to bring the unsupported technology (Lotus Notes) into support at a cost greater than $1.2MM, and a component of our platform, Domino Documents, was marked "end of life" by IBM (dropped from support). The technology decision to move to SharePoint as the standard collaboration platform was made prior to the start of Wave 1.	The company use SharePoint as its collaboration platform. Lotus notes is being retired as the collaboration platform. This phase will move the final set of applications and database to the SharePoint Platform.	The key benefit is Lotus Notes will be retired and no longer need to be maintained. By migrating to the SharePoint platform there is added benefit for the migrated applications and databases, including: - Sites enabled to leverage new functionality/features found in SharePoint - Increased security and reliability of key business processes and data, while reducing risk footprint and cost of maintaining an unsupported standard (Lotus Notes) - The use of K2 enables users to modify their sites/applications to tailor to their business needs	Jan-19	Mar-19	May-19	Nov-19	Nov-19	(0.93)
26	Redwood Cronacle Upgrade	Asset Refresh Program	839,596	-	-		-	The project will upgrade Redwood Cronacle batch job scheduling software to the latest version	The alternative is to do nothing. The upgrade will enable currency in terms of the application version and the operating system version.	Redwood Cronacle is the Company's batch Job Scheduler software that processes ~ 4000 scripts controlling critical business processes, including customer billing and payment, payroll and financial processing. The project will upgrade Cronacle to Version 9 which will help sustain business operations on a current and supported version.	The project will upgrade the Redwood Control Process Scheduler application to the latest release of available to sustain business operations on a current and supported platform. This will remediate the risk to our critical business processes, including customer billing and payment, payroll and financial processing.	Feb-19	May-19	Jul-19	Dec-19	Dec-19	(0.92)
27	Enhancements - Corp	Corporate and Enterprise	814,547	$0.100	-	-	-	Small software enhancement work efforts performed for the Corporate Services business areas.	An alternative is not to provide funding for enhancements. However, this then limits our ability to provide process improvements, retire applications, make changes related to customer and employee safety, and meet legally required HR and Finance changes.	Project scope includes making enhancements for Finance, Human Resources (HR), Learning & Development, Legal, Governmental, Regulatory and Public Affairs, and Corporate Security.	These enhancements for Corporate areas result in operational efficiencies, avoided costs, reduced risks and compliance to meet legally required Human Resource and Financial changes.	NA	NA	NA	NA	Dec-19	(0.90)
28	Fleet Work Management Improvements	Engineering	785,668	$0.574	-	-	-	Implement work order, parts lookup, and time entry processes into a single mechanics application ensuring efficiencies in the charging of time and parts to fleet work orders.	Alternative considered will to continue the use of GuiXT to add the necessary functionality that the GuiXT tool will allow. GuiXT limits the ability to take advantage of future technology enhancements. This alternative limits the ability to merge multiple processes into a single mechanic personas, thereby reducing proposed benefits. Furthermore, it limits the ability to move to a mobile platform, whereas the new solution can be implemented with a mobile technology.	Project scope will include bringing 3 different mechanics views (work order, parts lookup, time entry) into a single Fleet mechanic view. System health for all mechanics work will also be captured and presented via dashboard.	The project will add the following value: 1. Improves mechanic efficiency by having relevant work order and vehicle parts information in a single view, reducing administrative time. 2. Provides a more efficient time entry for work order process through a single work order/time entry view, increasing time entry accuracy. 3. Provides enhanced reporting capabilities, including dashboarding for vehicle to work order information, allowing efficient tracking and insight to vehicle status for multiple areas. Streamlined applications for fleet mechanics creates efficiencies for work order management, reducing administrative time and increasing the speed of repairs and maintenance. These changes enable less down time for fleet vehicles and equipment, and increase in-service time to meet customer needs.	Feb-19	Mar-19	Apr-19	Oct-19	Aug-19	0.29
29	Enhancements - Cust Exp-Ops	Customer Experience and Operations	760,243	-	-	-	-	Small software enhancement work efforts performed for Customer Experience business areas.	Many of the enhancements completed in this portfolio impact employees that manage customers (contact centers, complaints, billing, revenue recovery, etc.) The alternative would be to not do enhancements, however, that limits the company's ability to improve the applications that benefit employees who are serving customers. Additionally, customers provide feedback on website, IVR and other payment options. Limiting enhancements prevents the company from meeting the customer's request for improvements.	Enhancement functionality includes MPSC mandatory changes; enhancements to billing and dunning for low income customers; enhancements to IVR to improve customer experience; enhancements to website based on customer feedback and enhancements that improve processes all resulting in savings.	Each enhancement request has defined business value.	NA	NA	NA	NA	Dec-19	(0.98)

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30	ARP - Operational Technology Support	Asset Refresh Program	689,971	-	-	-	-	Asset refresh project for infrastructure supported by Operational Technologies (OT). Replace assorted critical infrastructure due to obsolescence hardware as identified per 5 year budget planning/forecast. IT provides both hardware and labor funding. OT technologies covered by this ARP are Server, Workstation, Storage and Network devices including field communication devices that are managed by the OT department.	Extending maintenance was considered for systems vs. replacing. Industry analysts Gartner and IDC both recommend a 5 year replacement cycle for data center and CE has adopted this approach. Doing nothing will cause some systems to become unavailable to the IT system End User as normal growth will exceed the compute resources currently available.	The requirement is to replace and upgrade the in scope items with current technologies. The project will replace functionality without necessarily doing a like-for-like replacement of the asset. For example, instead of replacing 20 servers with 20 servers, converged infrastructure will be implemented.	Applications will have a lower risk of operational outages. Updated applications will benefit from better compatibility and increased capacity/performance and our maintenance costs will decrease as a result.	NA	NA	NA	NA	Dec-19	(1.07)
31	Fleet Telematics	Generation and Field Operations	682,433	$0.334	$0.208	-	-	Fleet Telematics provides the ability to monitor the location and movement of fleet vehicles by Operations Work Management scheduling and dispatch. It also provides Fleet with vehicle utilization and health statistics data.	Alternative - minor upgrade to next supported vendor version only. This alternative would provide nothing for vehicle telematics and would primarily support vehicle monitoring and location.	Project Scope includes providing Dispatch with vehicle monitoring and location information including geo-fencing. Fleet will have access to fleet vehicle telemetry data, and driver behavior data. The Fleet Telematics system will also provide the ability to support all existing reports currently used by stakeholders today.	* Increase customer safety as the tool allows the dispatcher to select the appropriate field worker/crew to respond to emergency calls, by being able to select the closest in proximity to the emergency. * Increase Field Employee Safety with accurate location of field crews (via their vehicle location) prior to the energization of circuits * Reduction in Gas Emergency Response time through the identification of the closest Gas Field Crew to that emergency Reduction in Fleet vehicle maintenance costs by utilizing telematics information for predictive and preventative maintenance.	Jul 2019	Oct 2019	Dec 2019	Nov 2020	Nov-20	(0.37)
32	ARP - F5 Refresh	Asset Refresh Program	673,879	-	-	-	-	This project will refresh the company's F5 Load Balancing equipment. The F5 hardware was purchased in 2011 and the industry average refresh cycle is 5 years.	If we do nothing, the risk will be using obsolete equipment that will be prone to higher failure rates, resulting in an increase of unplanned outages and potential security vulnerabilities. Alternate load balancing technologies exist, however, they do not have the feature sets required to meet our application needs.	1) Refresh obsolete F5 equipment. 2) Determine required feature sets for new Load Balancer. 3) Implement new F5 according to industry best practices.	Value is provided by increasing the reliability for customer and business facing applications. Increasing the reliability of this system has a positive impact on safety and customer metrics.	NA	NA	NA	NA	Dec-19	(0.96)
33	SAP Archiving	Asset Refresh Program	668,615	-	-		-	SAP data is growing at the rate of 500 GB a month. This has impacts on system stability and functional viability, and increased liability on the enterprise due to lack of archiving and destruction policy for SAP data. The project enables archiving of the data based on the residency and retention periods defined by the business and legal. In 2018, the areas of archiving include SAP Change documents, Finance Accounting documents, and Work Orders.	If we do not archive the data, the SAP database size will continue to grow and hence deteriorate application performance. It will also decrease system stability and increase operational costs.	(1) Meet compliance requirements by purging any data that can become a liability as identified by CE legal team (2) Build an Archiving solution that allows the business to retrieve archived data with ease and in the form that is needed	1. Will increase system stability by reducing exponential data growth in SAP. 2. Will reduce company liability by introducing an archiving policy for data. 3. Will enable future transition to SAP HANA which is a requirement by SAP in the next five years by reducing database size for migration. 4. Decrease maintenance windows, and time and storage needed to back up data. Customer benefits are: 1. Predictable SAP system performance 2. Higher system stability 3. Reduction in system outages due to better database stability and growth rate	NA	NA	NA	NA	Dec 2019	(0.95)
34	ECM - ProjectWise Phase 2	Engineering	639,579	-	-	-	-	ECM-ProjectWise Phase 2 will integrate the Engineering Content Management Phase 1 solution into SAP®, linking our enterprise work management system with ProjectWise and replacing WRAD (Work Requirements and Design) File Manager (WFM) functionality. Phase 2 will expand to new user base in engineering and engineering planning areas, configuring the software and creating workflows to support business functionality for each area.	The majority of records are electronic, so non-technology alternatives were not considered. SharePoint was considered as an alternative, and a document warehouse repository within SharePoint was not a viable solution because it lacks the ability to integrate with the computer aided design (CAD) software while maintaining native file formats and complex design relationships within CAD files. Furthermore, SharePoint does not offer a geospatial integration that allows searching and storing spatially located drawings, create spatial relationships with files, nor allow third party file sharing. Implementing a centralized Engineering Content Management software is key to a robust, mature management system that overcomes current methods of storing records by project or by individual completing the work.	Project scope includes building an integration with the SAP document management system to ProjectWise, initiating ProjectWise workflows from SAP, linking notifications generated by a maintenance plan to the asset folder in ProjectWise, and configuring workflows for new user groups.	1. Further mitigate risks with ineffective document management processes for asset records by providing complete, traceable, and verifiable records. 2. Increase in safety and compliance that is realized through a single source of truth for documentation of company assets. Create a single resource for construction and as-built drawings, eliminating the possibility of someone performing work based on an out of date print or schematic. 3. Create central repository for asset records that is readily accessible and easily searchable audits, investigations, and for end users performing engineering work modifying existing assets and/or designing new assets. CE shares current and as-built record information with third parties, including municipalities, engineering firms, staking contractors, auditors, and permitting agencies. Effective document management will improve response time for design review, permit changes, audits through secure, direct third party access; reduce rework by establishing electronic document workflow and design parameters; and reduce paper waste through electronic document transmittal.	Feb 2019	May 2019	Aug 2019	Dec 2019	Dec 2019	(0.94)
35	Wireless LAN Redesign	Asset Refresh Program	566,820	-	-	$0.050	-	This project is to address the aging Wireless Local Area Network (LAN) Infrastructure at Company locations throughout the State. The project will replace aging infrastructure with newer equipment that is capable of providing higher throughput for clients and more advanced feature sets than the current wireless LAN. This project will address the issue of coverage not being consistent at all Company locations. The current Wireless LAN was deployed mostly due to "organic growth". Many of the Company locations do not have the ubiquitous Wireless coverage that Business Partners have come to expect, this project would provide seamless coverage in the Company's office locations.	Do nothing and continue to address lack of coverage on a case by case basis. The company will not be able to support new wireless devices that offer higher throughput and will not be able to support mobility at all company locations.	The project will collect survey data for all company locations and design wireless coverage based survey results. Deploy new Wireless Access Points to company locations. Verify coverage is as expected. The company will not be able to support new wireless devices that offer higher throughput and will not be able to support mobility at all company locations.	Providing full Wireless coverage at all Company locations will enable higher productivity of our employees by providing connectivity beyond the desktop and better position the Company for the adoption of the "Internet of Things". Increasing the productivity of our employees will help us serve customers more efficiently.	Jan-19	Feb-19	Apr-19	Dec-19	Dec-19	(0.98)

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36	ED - ARP OSI HVD and LVD SCADA Upgrades	Engineering	556,376	-	-	$0.050	-	The Electric Distribution (ED) Asset Refresh Project (ARP) upgrades OSI Supervisory Control and Data Acquisition (SCADA) application for High Voltage Distribution (HVD) and Low Voltage Distribution (LVD) systems. Biennial hardware refresh included.	CE targets OSI SCADA biennial application upgrades to stay within 2 versions of the application. One alternative considered is to reduce the frequency of application refresh rates. However, given the critical nature of the SCADA system, the option of not completing biennial upgrades is not a prudent business decision, as it increases security risk and vendor application support.	The scope of this project is a software upgrade to the High Voltage Distribution (HVD) supervisory control and data acquisition (SCADA) software. The HVD SCADA is used to control generation and high transmission and distribution voltage circuits.	Upgrading the HVD SCADA software will ensure that when problems occur, they are promptly addressed. Additionally, upgrades include enhancements and fixes to the core product that support reliability of electric delivery, ensuring that customers receiving the energy they need when they need it. Because the reliability of the entire distribution system is dependent on availability of the HVD system, staying relatively current with the solution provider upgrades is critical. If upgrades are delayed, additional full time resources will be required for 1 year to address upgrade complexities.	Mar-19	May-19	Oct-19	Dec-19	Dec-19	(0.98)
37	Source to Pay	Engineering	530,580	$1.003	$14.088		-	Implement an extension of the SAP Ariba products (Contract Management and Spend Visibility) currently in use. Sourcing and procurement software modules from SAP Ariba will be used in streamlining the procurement processes, drive compliance and control while reducing costs and risks. This software will allow automated approval flows and integration with the various business networks.	A Request for Information was conducted that included "source to pay" software providers (SAP Ariba, Coupa, Power Advocates and GEP). SAP Ariba is currently in use at Consumers Energy for Contract Management and Spend Visibility.	Implement extensions to Supply Chain and Accounts Payable business functions. This includes source to pay software that includes sourcing, supplier, procurement and automated invoice functionality.	SAP Ariba modules Supplier, Sourcing and Procurement will achieve sustainable cost savings throughout the procurement process with strategic sourcing software using SAP Ariba. The cloud-based solution will implement a closed-loop, automated process – for fast, flexible sourcing and significant savings. • Save time and facilitate repeatability by automating the RFX process • Capture best practice processes to ensure consistency and knowledge transfer • Get the best bid for 3rd party goods and services with electronic auctions • Establish contracts directly from the RFX or auction stage • Speed supplier proposal evaluation with scoring and optimization tools • Cloud-based software solution that aligns with CE's SAP ARIBA Contract Management and Spend Visibility additions • Single, web-based location to register and manage supplier information facilitate efficient customer organization collaboration Efficiencies gained through the source to pay efforts will see cost savings in materials and services which will benefit the rate paying customer.	Jan 2019	Feb 2019	Apr 2019	Oct 2020	Oct 2020	5.00
38	ARP - Cyber Security	Security	523,800	-	-		-	The objective for this project is to ensure continued vendor support of cyber security technology deployed at the Company as well as reduce the risk of unplanned outages due to outdated hardware/software and appliances. Replace end of life and obsolete systems; leading to less probability of equipment failures, software compatibility issues and internal systems downtime.	The alternative is to not do this work and assume cyber risks associated with having outdated cyber security assets and systems, which may result in penalties and reputational damage.	The Cyber Security Asset Refresh project is intended to ensure continued vendor support of security technology deployed at the Company as well as reduce the risk of unplanned outages and increased security vulnerabilities due to obsolete /end of life hardware/software and appliances.	Reduces the risk of downtime of systems needed to prevent cyber related incidents and detect vulnerabilities. Replace old/obsolete hardware which has a higher risk of failure and could hinder security monitoring to detect attacks against critical systems. This will ensure internal business users are able to continue to access the network and applications.	NA	NA	NA	NA	Dec-19	(1.09)
39	Replace and Re-badge	Security	523,176	-	-		-	Replace current outdated badge readers with new multi-class readers. Once multiclass readers are in place, we will rebadge company employees and contractors. (higher security and less vulnerable to cloning).	Alternative is to continue with current badge readers/badges that don't have a safeguard to badge duplication, leaving the Company at a higher vulnerability to the cloning of Company badges	Replace outdated badge readers and rebadge employees and contractors.	Security Risk Avoidance/Mitigation. Because of this '99 technology our current badges can be cloned, with the new readers/badges we will be able to encrypt them , which will give us stronger security. Keeping our sites safe and secure provides reliability of service and business continuity for our customers.	Jan 2019	Mar 2019	Jul 2019	Jan 2020	Dec-19	(0.98)
40	Enhanced Customer Data Analytics Platform	Customer Experience and Operations	463,750	-	-		-	Create a comprehensive and analytical view of customers across various classes encompassing outages, billing history, payment history, customer usage and payment channel for the purpose of segmenting and providing improved customer experience.	An alternative is to continue to operate as today, leaving us without a comprehensive view of our customers and their experiences with CE.	The initial scope of this project is to include various business partner data, rates and billing data and history; various programs our customers are enrolled in; complaints filed by customer and customer preferences. This data will integrate with our Business Warehouse to provide a comprehensive view of our customer.	Provide a single source for all of the customer interaction data within the utility. Provides analytics for modeling, and execution of one on one customer interactions. These analytics will provide insights into the various customer journeys and experiences allowing CE to determine opportunities to improve that experience across all channels. Here are the benefits to the customers of the project as it relates to website and contact center: Website: • We will deliver a more personalized experience that is expected to improve customer satisfaction. When we understand the attributes and preferences of our customers, we can tailor a personalized experience for each customer that logs in to their account on our website. The personalization may include: o Information about Energy Efficiency programs o Information on how to set up a payment arrangement or receive assistance paying their bills o Benefits of enrolling in our Demand Response programs o Other products and services we offer that are applicable to them Contact Center: • Allow agents to personalize the experience of the customer, with the expectation of improving customer satisfaction, by: o Providing the agents information about the customer's journey with Consumers Energy (billing, payments, website visits, outages, calls to contact center, and more) o Allow agents to recommend the "next best action" for the customer (may be a payment plan, enrolling in proactive alerts, participating in an Energy Efficiency program, etc.) o Predictive call analytics – identifying why the customer is calling before they have to tell us	May 2017	Jun 2017	Aug 2017	Nov 2019	Nov 2019	(0.97)
41	ESB Upgrade	Asset Refresh Program	436,149	-	-	-	-	The Enterprise Service Bus (ESB) is an Enterprise Integration Platform initially implemented to support the Advanced Metering Infrastructure (AMI) Smart Energy Applications. It enables secure flow of data from Smart Meter head ends to SAP and other systems that process and store the data.	If we don't do this upgrade, several of the products will be out of mainstream support, as well as the server operating system. Additionally the expected benefit of upgrading the application suite will not be realized.	Project scope is the upgrade all components of the enterprise service bus, and refresh underlying infrastructure as needed.	This project will provide the users with more current versions of software to better meet business requirements. Additionally the project will resolve all current issues with application versions and infrastructure thereby saving expenditure on maintenance extensions and remediating risk due to unsupported technologies running in production.	Sep-19	Nov-19	Jan-20	Dec-20	Oct-20	(0.91)

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42	Enhancements - TEOS	Engineering	428,453	-	-	-	-	Small software enhancement work efforts performed for the Transmission, Engineering, and Operation Support business area.	Many of the enhancements completed in this portfolio impact employees that perform engineering design for customers, manage commodity supply and storage, manage regulatory compliance requirements, and support customer-facing work groups (i.e.., safety, fleet, facilities, supply chain, project management). The alternative would be to not do enhancements, however, that limits the company's ability to improve the applications that benefit employees who are serving customers.	Enhancement functionality is diverse, given the wide range of applications in use, and includes: regulatory compliance mandatory changes, improvements to engineering and design applications, and minor functionality improvements across the spectrum. Enhancements are minor changes that are impactful to day-to-day work processes performed in these applications.	Each enhancement request has defined business value including incremental cost savings, avoided costs, productivity improvements, operational efficiencies, waste and rework reduction, regulatory compliance, safety risk reduction, and improved customer response time.	NA	NA	NA	NA	Dec-19	(0.98)
43	ARP - Infoblox Refresh	Asset Refresh Program	401,893	-	-	-	-	This project will refresh the company's Infoblox (Domain Name System (DNS), Dynamic Host Configuration Protocol (DHCP), and Internet Protocol (IP) address management) equipment that was purchased in 2013. Infoblox enables organizations to more efficiently manage and control their networks, reduce risk and gain insights for better decision making. The industry average for Infoblox hardware refresh is 5 years.	If we do nothing, the risk will be using obsolete equipment that will be prone to higher failure rates, resulting in an increase of unplanned outages.	1) Refresh obsolete Infoblox equipment. 2) Determine required feature sets for new equipment. 3) Implement new Infoblox according to industry best practices.	Hardware (HW) is nearing end of life. Company could experience network outages if HW fails due to obsolescence or lack of support from vendor. Refresh will ensure business is able to continue to access the network and applications to perform their jobs. This will help us to serve the customer by insuring our IT systems are functional.	Feb 2019	Mar 2019	Apr 2019	Aug 2019	Aug 2019	(1.02)
44	Corporate Capital	Corporate and Enterprise	396,000	-	-	-	-	This line item is used to fund onboarding, moving, and equipping expenditures for senior officers, corporate officers, and corporate departments.	Not funding this initiative can lead to a higher failure rate and lost productivity due to equipment failure. The video equipment contributes to many types of communications within the various corporate organizations. The facility moves of officers and directors are critical to effective communication and collaboration between a cross-functional organization.	Scope in the past has included IT equipment and related peripherals, video equipment, and facility moves.	Improvement of communication methods and speed of transactions between top level organization leaders, and an avoidance of technology obsolescence and failures.						
45	Financial Planning Transformation - Phase 2	Corporate and Enterprise	385,681	$0.265	-		-	This is the second phase in a technology roadmap to implement a company-wide suite of solutions to mature the company's operational planning activities. This phase supports monthly plan management while the first phase was limited to annual planning.	Alternative: Do nothing: Continue to leverage unconnected, individual excel files, access databases and SharePoint lists. High level of data integrity risk; highly manual effort; significant rework and duplication of efforts and data. Absence of centralized data and visibility.	The scope of release 2 is focused on supporting and facilitating monthly plan management.	The visibility of the linkages between financials and performance will allow us to better optimize our portfolio of work. This will ensure we are investing the right amount in the right areas, functions and assets thus reducing risk. This will reduce ad hoc reporting, reduce report-to-report reconciliation and enable automation of utility-wide plans down to the optimal level of detail.	Jan 2019	Mar 2019	Jun 2019	Dec 2019	Dec 2019	(0.07)
46	SAP Work Order Overtime Allocation	Generation and Field Operations	385,160	$1.440	-		-	This project will enable the direct attribution of Overtime Costs to the impacted Work orders instead of spreading Overtime costs across all work orders and update the Capital Non-Asset program to meet Property Accounting Standards by utilizing activity types and additional Internal Orders (IOs) to better allocate costs to source programs.	Alternative: Two alternatives were considered. One was a do nothing approach where field worker overtime costs would continued to be spread across all work orders. The second alternate explored, included integrating SAP HR/Payroll with the SAP Plant Maintenance modules. This alternative involved extensive SAP customization and therefore was considered a high risk when associated with SAP future maintenance and upgrades.	Scope includes new configuration and functionality of the SAP Project Systems module to attribute Overtime cost directly to impacted Work orders versus the spreading of that cost across all work orders	This project provides Operation Program Managers better insight where we spend overtime on work; therefore, changing behaviors and practices to shift overtime spend. Additionally we would be able to identify those programs contributing more to overtime than others so measures can be taken to address chronic overtime occurrences with better planning or staffing decisions.	Jan 2019	Feb 2019	May 2019	Nov 2019	Nov 2019	3.90
47	Enhancements - Operations	Generation and Field Operations	360,309	-	-	-	-	Small software enhancement work efforts performed for the Operations business area.	Many of the enhancements completed in this portfolio impact employees that perform electric, gas operations for customers, (i.e.., gas and electric operations, financial planning, work management, operation performance, generation operations and compression). The alternative would be to not do enhancements, however, that limits the company's ability to improve the applications that benefit employees who are serving customers.	Enhancement functionality is diverse, given the wide range of applications in use, and includes: work management application updates, outage management systems, outage map updates, regulatory compliance mandatory changes, improvements to engineering and design applications, and minor functionality improvements across the spectrum. Enhancements are minor changes that are impactful to day-to-day work processes performed in these applications.	Each enhancement request has defined business value including incremental cost savings, avoided costs, productivity improvements, operational efficiencies, waste and rework reduction, regulatory compliance, safety risk reduction, and improved customer response time.	NA	NA	NA	NA	Dec-19	(0.96)
48	TCOE Test Data & Environment Management	Asset Refresh Program	348,700	-	-		-	The purpose of this project is to implement the tool(s) and techniques for our Testing Center of Excellence (TCOE) to be able to periodically (e.g. annually) refresh our data in our SAP development and QA environments from production. It is a continuation of the work started in 2018. Our SAP test data is stale. Our SAP development environments have never been refreshed and our QA environments can go 5+ years without refreshes. This results in slower delivery since much time is needed to find and update data. This can also impact quality since testing is sometimes limited based on test data constraints especially in the development environments.	We are currently exploring different options, different tools with different approaches, for addressing our challenges with SAP test data. Alternatives are being explored during the Plan phase of the project. The alternative of not addressing our SAP test data problem is not recommended since changes to SAP and SAP interfacing applications are taking longer and costing more to do. More importantly, the quality of the changes is at risk.	Implement the tool(s) and techniques to be able to refresh the SAP development and QA environments. Perform appropriate obfuscation of sensitive data copied from production. Ensure the entire refresh process can be done within a long weekend to minimize outage time. Refresh one development and one QA environment and put the processes in place to refresh the rest on an on-going, periodic basis.	With improved SAP test data, our manual testing efforts will decrease, improving speed to deliver and reducing costs. Further, the quality of testing will improve and therefore the quality of the solutions will improve. This is true for all SAP applications and SAP interfacing applications including customer applications such as CRM, our CE.com web site and customer billing.	Dec 2017	Mar 2018	May 2018	Jun 2019	Jun 2019	(0.94)
49	RPA Capability Enhancements	Asset Refresh Program	347,113	-	-		-	With an initial Robotic Process Automation (RPA) capability in place, this project is to expand the features and breadth of deployed use cases - further enabling the productivity and quality gains that result from this form of automation. These features can include, but are not limited to machine learning and natural language processing (such as in chat bots).	In 2017, the company looked at possibilities and solutions to do Robotic Process Automation. It includes various platforms and vendors. If we do nothing, we will continue to execute repetitive, time consuming processes manually - which has a higher cost, slower process/business outcomes, and increased risk of human error.	The digital workforce of our current Robotic Process Automation capability is limited to the scripted and structured unassisted automation. The scope of this project will be to enable and employ new features within our current RPA platform that can deliver faster business outcomes. These features can include, but are not limited to machine learning, and natural language processing.	Benefits of Robotic Process Automation include the reduction of human errors, operational cost savings and/or avoidance, an increased workforce capacity for high value work in processes across the business, and quicker process execution to deliver outcomes - including those within the customer front/back-office domain. The specific benefit targets are contingent on which process candidates are automated to leverage this new functionality.	Jan 2019	Feb 2019	Apr 2019	Dec 2019	Dec 2019	(0.94)
50	Gen Ops Work Management Mobility	Generation and Field Operations	336,884	$0.015	-		-	Provide Generation plant maintenance & operation personnel with durable, mobile devices and software, and improve wireless internet connection. Data retrieved and updated would include procedures, equipment statistics and work orders.	Alternative considered included continuing with the manual paper-based process. Risks associated with that approach include work performed using outdated procedures, inability to access safety procedures, and productivity.	Replaces paper-dependent work management process with ability to access and update maintenance, operations and safety information. This includes mobile devices, software and wireless connection enhancement.	Productivity: reduce need to return to kiosk/desk for updates; Quality: better updates when done right at time/place; Safety: current information at worksite vs. printed procedure/drawing; Employee Engagement: candidate pool looking for mobility in jobs.	Mar-19	Apr-19	Jul-19	Jun-20	Jun-20	(0.95)
51	SAP Security	Security	261,525	-	-		-	The purpose of this project is to provide vulnerability scanning of SAP specific platforms. The project will include requirements gathering, vendor selection, product selection, tool design, configuration, and implementation.	The alternative is to continue semi-manual scans and reacting to potential impacts due to Organization inability to proactively identify potential security issues with SAP systems and lacking visibility to detect and respond when issues do occur.	There is no functionality being delivered for this project in 2019. There is only a final payment to the vendor associated with the project that will need to occur, as the project will conclude in late 2018.	This project closes a security vulnerability scanning gap that our current information tools do not provide for new systems and solutions in our SAP environment.	NA	NA	NA	NA	Dec-19	(0.97)

Line No.	(a) Project	(b) Company IT Category	(c) Capital Costs - Approved Amounts	(d) O&M Savings	(e) Capital Savings	(f) Contingency - Capital	(g) Contingency O&M	(h) Project Description	(i) Alternatives Considered	(j) Project Scope/ Functionality	(k) Project Benefit	(l) Plan - Start Date	(m) Define Start - Date	(n) Execute - Start Date	(o) Close - Start Date	(p) Go - Live Date	(q) Cost Benefit Ratio
52	PowerPlan Application Upgrade	Corporate and Enterprise	220,424	-	-	$0.015	-	This project is a carry-over from 2018 to upgrade the functionality in PowerPlan to support ASC 842 – Accounting Standards Codification – Leases (Topic 842)	If this project is not done, the manual monthly effort required to account for these leases would be burdensome plus the possibility for error is greater with manual entries. Switching to another tool was not considered since we already use PowerPlan and most large utilities use it.	PowerPlan will be upgraded to support the new accounting Standard. All leases (that qualify as a lease) will be brought onto the Balance Sheet.	Consumers Energy complies with ASC 842 – Accounting Standards Codification – Leases (Topic 842).	Jan 2019	Mar 2019	May 2019	Sep 2019	Sep 2019	(0.79)
53	Portable Security Cameras	Security	209,560	-	-		-	Mobile Security Trailers that allow real time viewing of assets on project sites (Enhanced Infrastructure Replacement Project); high crime areas, and other applications as needed to protect our employees and assets.	The alternative is to continue utilizing security guards. By doing so, we are more acceptable to risk, such as guards sleeping, guards monitoring one areas while theft is occurring in another, or potentially not having coverage if the guard doesn't come into work.	Project will include the purchase of 7 new security pole cameras (to replace the old ones) and purchase 2 additional security pull camera trailers. These items are used for security surveillance at multiple locations (Company and Non-Company Locations). They are used as a visual deterrence and also record the area so we are aware of everything going on. The 2 security pull camera trailers we have are in high demand and are being used constantly, and we need more to help cover the need.	This project brings benefits to our customers by way of ensuring our assets are protected by eliminating human factors. This project will allow us to provide recorded security surveillance to more than a couple of areas at a time. We currently mitigate the risks associated by using contracted security guards to perform this function in addition to some of their other duties to provide protection of the utility assets. Utilizing mobile security trailers eliminates payment associated with staffing a guard to monitor our assets.	Mar 2019	Apr 2019	May 2019	Jan 2020	Dec-19	(0.93)
54	Virtual Command Center Software	Security	174,932	-	-		-	Software that monitors news events, can be custom tailored to our specific geographic areas. News, Weather, Traffic, can be monitored. Security Command Center could send safety alerts out based off of data being monitored.	Alternative is to continue with manually intensive checks, which constrains resources from working on other activities that may mitigate security risks.	These new modules will allow us to use automated documents for compliance using auditing and/or assessment methods designed to evaluate our company sites. More functionality to improve our current camera capabilities. Also the logic driven software will create faster technology in bringing up information for all our sites, making our Security Command Center more efficient.	We currently have manual processes in place, which result in significant amounts of follow up and data approvals. Automation of this work frees up resources to focus on other activities that mitigate security risks. Keeping our sites safe and secure helps provide reliability of service and business continuity for our customers.	Feb 2019	Mar 2019	Jul 2019	Jan 2020	Dec-19	(0.91)
55	TCOE ALM Upgrade 2019	Asset Refresh Program	133,536	-	-	$0.025	-	Micro Focus Application Lifecycle Management (ALM) is our primary testing tool utilized by the Testing Center of Excellence (TCOE). It holds our test case repository enabling reuse of test cases across various initiatives. It contains test evidence, storing test results. It is used for test status reporting. It is used for defect management. This project upgrades Micro Focus ALM to the current version to ensure we stay on a supported version.	An alternative is not upgrading and assuming risk of running software that is not supported by the vendor. If problems are encountered that require support (fixes) from the vendor, we would not be able to correct. This could adversely impact our ability to test. Our ability to reuse existing test scripts would be at risk. And our ability to follow our IT Controls around capturing test evidence would be at risk.	Micro Focus ALM is our primary testing tool for managing testing scripts . The project scope is to upgrade Micro Focus ALM to the latest version so that it will continue to be supported by the vendor. The scope includes performing the upgrade of the application as well as performing regression testing to ensure it still functions as expected. We will also analyze new functionality that is available with the new version and implement new features as appropriate.	Micro Focus ALM is used to create a test case (test scripts) repository so that test cases can be reused across many application changes. Micro Focus ALM is also used to capture testing defects and manage the defect lifecycle through defect closure. Finally, Micro Focus ALM is used to track and manage test execution progress to ensure all tests are appropriately run. In short, Micro Focus ALM helps ensure quality and repeatable testing, which in turn helps ensure quality application changes. These benefits are for all applications including customer applications such as CRM, IVR, our CE.com web site and customer billing. Further, by doing the upgrade, we would continued to be on a version of the software that is supported by the vendor. If we have any issues, we'd be able to get support and fixes from the vendor.	Mar 2019	May 2019	Jun 2019	Sep 2019	Sep 2019	(0.95)
56	Credit and Collections	Customer Experience and Operations	65,736	$1.875	-		-	The Credit Collections project is an opportunity to improve our collections rate via our outside collections agencies by enhancing our visibility and tracking of uncollectable expense via middleware. This project will implement Debt Next solution to support the lowering of uncollectable expenses.	The alternative is to do nothing and operate as we do today, however, savings would not be realized of increasing uncollectibles and employee productivity.	Implement Debt Next, a cloud solution to allow for the lowering of uncollectible expenses. Allow payments to be uploaded and credited to a customers account automatically; provide reports that provide details on debt and aging of debt, and ability to move accounts for better vendor management.	Technology Benefits: Debt Next - Cloud computing vs IT resources; a customized system to meet business needs; Reporting capabilities will provide more information on age of inventory and details on the reduction in write-offs; People Benefits - Debt Next - increased productivity due to reduction in time to audit and complete invoice reconciliation; Enhanced Communications - Easily understand, new communication channels (i.e. Postcards); Process Benefits - Debt Next -easily manage third party collections vendors and the accounts placed with them; ability to quickly transfer accounts amongst vendors; Financial Benefits - Debt Next - Decreased uncollectibles; reduce cost, and improve operations.	Apr 2018	Apr 2018	Oct 2018	Nov 2019	Nov 2019	5.00
57	Mass Notification - Upgrades	Security	55,097	-	-		-	Provides the capability to communicate with desktop servers (send an alert out to desktops); and to activate a "Blue Light" at the service centers during an event (active shooter/lockdown, etc.…) via the MNS system;	The alternative is to not implement the capability to send mass notifications via desktop services during an event. At the present time, an average of 25%-30% of the total workforce is missed using the current method.	Implement/upgrade Siemens Fire-Panels at company locations. Similar to current capabilities used to announce "fire" events, the mass notification tool will allow notifications for other events requiring notifications to building participants.	This is directly tied to safety. Safety is increased by allowing better communications to employees and guests during emergency situations. Customers will be benefited by being directly notified of a situation while at one of our sites (i.e. Direct Payment Office).	Feb 2019	Feb 2019	Jun 2019	Nov 2019	Nov 2019	(0.86)
58	TCOE LoadRunner Upgrade 2019	Asset Refresh Program	34,870	-	-	$0.008	-	Micro Focus LoadRunner is our load testing tool utilized by the Testing Center of Excellence (TCOE). This tool is needed to ensure that application changes don't adversely impact performance. This project upgrades LoadRunner to ensure we stay on a supported version.	An alternative is not upgrading and assuming risk of running software that is not supported by the vendor. If problems are encountered that require support (fixes) from the vendor, we would not be able to correct. This could adversely impact our ability to do load testing. Without being able to load test, we would be at risk for implementing changes into production not knowing whether they would perform satisfactorily. This could lead to disruption of dependent business processes.	Micro Focus LoadRunner is our user load testing tool. The project scope is to upgrade LoadRunner to ensure we are on a supported version. New tool features will be evaluated and possibly leveraged. Testing will be done to ensure that the existing load tests continue to function as well as to ensure that we can create and execute new load tests.	With LoadRunner, we can emulate load on an application such as having 300 users executing a total of 3,000 transactions an hour. This will help ensure that application changes can handle production loads before they are implemented so production is not adversely impacted. LoadRunner is used to conduct load tests on a variety of applications including customer applications such as CRM, IVR, and our CE.com web site. Further, by doing the upgrade, we would continue to be on a version of the software that is supported by the vendor. If we have any issues, we'd be able to get support and fixes from the vendor.	Mar 2019	Apr 2019	May 2019	Jul 2019	Jul 2019	(1.02)
59	Operations Application Currency	Generation and Field Operations	14,496	-	-	$0.001	-	This effort is needed to ensure application currency for the Operations (Gas, Electric & Generation) Application Portfolio. The application upgrades have been prioritized based on business criticality and value, and this project will perform the routine upgrades/maintenance to ensure IT solutions supporting Operations business processes to deliver energy to our customers are stable and current.	The alternative considered was not upgrading and assuming risk of running software that is not supported by the vendor.	The Operations Application Portfolio went through an assessment to evaluate application currency and technology obsolescence for this portfolio, prioritized needed upgrades based on business criticality and value, and this project was initiated to address priorities to ensure appropriate support and performance.	This project covers application currency for several Operation based systems that ensure Safety, Quality, Performance, Reporting (Welder Qualifications - ensuring that workers are qualified to do specific work, DORMOR - data reporting system that provides plant data such as MW Produced, heat rate, etc. to Executive Leadership, etc.).	NA	NA	NA	NA	Dec 2019	(0.94)

60 "h." The percentage of total [Information Technology] budget that the top 25 projects represents, and total number of projects that fall outside of the top 25 are 81% and 34 projects respectively.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

DANIEL L. HARRY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric & Common O&M Expenses
for the Years 2017, 2018, and 2019
($000)

Case No.: U-20134
Exhibit No.: A-87 (DLH-1)
Page: 1 of 1
Witness: DLHarry
Date: May 2018

Corporate O&M

Line No.	(a) **Program Description**	(b) **2017 Actual**	(c) **2018 Projected**	(d) **2019 Projected**	(e) **Source**
1	Adjusted Corporate Services Expense	$ 50,852	$ 51,479	$ 52,562	Exhibit A-88 (DLH-2)
2	Uncollectible Expense	18,972	18,584	18,594	Exhibit A-90 (DLH-4)
3	Injuries & Damages Expense	4,487	4,590	4,675	Exhibit A-91 (DLH-5)
4	**TOTAL O&M EXPENSES**	**$ 74,311**	**$ 74,653**	**$ 75,831**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Electric Corporate Services O&M Expense
for the Years 2017, 2018, and 2019
($000)

Case No.: U-20134
Exhibit No.: A-88 (DLH-2)
Page: 1 of 1
Witness: DLHarry
Date: May 2018

Line No.	(a) Description	(b) 2017 Labor Actual	(c) 2017 Non-Labor Actual	(d) Total 2017 Actual	(e) 2018 Labor Projected	(f) 2018 Non-Labor Projected	(g) Total 2018 Projected	(h) 2019 Labor Projected at 1.017%	(i) 2019 Non-Labor Projected	(j) Total 2019 Projected
1	Human Resources and Admin.	$ 17,540	$ 5,650	$ 23,190	$ 16,598	$ 4,747	$ 21,345	$ 16,880	$ 4,828	$ 21,708
2	Internal Audit	732	821	1,553	821	742	1,563	835	755	1,590
3	Corporate Legal	3,442	1,141	4,583	3,641	612	4,253	3,703	622	4,325
4	Risk Management	1,388	13,342	14,730	1,356	14,596	15,952	1,379	14,844	16,223
5	Corporate Secretary	1,098	617	1,715	1,215	891	2,106	1,236	906	2,142
6	Governmental Affairs	3,319	2,345	5,664	3,223	1,422	4,645	3,278	1,446	4,724
7	Controller's Department	8,984	3,660	12,644	8,927	3,851	12,778	9,079	3,916	12,995
8	Rates, Regulatory Affairs	2,139	554	2,693	2,304	506	2,810	2,343	515	2,858
9	Strategy	603	1,455	2,058	1,098	1,211	2,309	1,117	1,232	2,348
10	Corporate Tax	1,644	935	2,579	1,592	769	2,361	1,619	782	2,401
11	Financial Forecasting	2,066	1,189	3,255	2,103	1,608	3,711	2,139	1,635	3,774
12	General Activities	(14,938)	(3,939)	(18,877)	(14,907)	(5,198)	(20,105)	(15,160)	(5,287)	(20,447)
13	Total	$ 28,017	$ 27,770	$ 55,787	$ 27,971	$ 25,757	$ 53,728	$ 28,447	$ 26,194	$ 54,641
14	Less: EICP			2,949			2,893			2,980
15	Less: Transfers Out			1,410			398			195
16	Total Corporate Service Departments			$ 51,428			$ 50,437			$ 51,466
17	Admin & Other-Electric Portion			1,696			1,866			1,920
18	**Total Corporate Services**			$ 53,124			$ 52,303			$ 53,386
	Normalizations									
19	Securitiztion III write off costs			(1,448)						
20	**Total Normalizations**			$ (1,448)			$ -			$ -
	Disallowances									
21	Corporate Giving, Communications, and Lobbying			(824)			(824)			(824)
22	**Total Disallowances**			$ (824)			$ (824)			$ (824)
23	**TOTAL ADJUSTED CORPORATE SERVICES EXPENSE**			**$ 50,852**			**$ 51,479**			**$ 52,562**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
S&P Global Market Intelligence ranking of Consumers Energy Electric A&G Costs for 2016
Ranked by A&G per Customer (less pension and benefits)
(Companies over 500K Customers)

Case No.: U-20134
Exhibit No.: A-89 (DLH-3)

Witness: DLHarry
Date: May 2018

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		2016	2016	2016	2016	2016	2016
Rank No.	Company Name	Total Customers (actual)	Total Admin & Gen: O&M Expense ($000)	Total Admin & Gen: Pension & Benefits ($000)	Total Admin & Gen: Excluding Pension & Benefits (d) - (e) ($000)	Total Admin & Gen: Excluding Pension & Benefits $/Customer (f)/(c) x $1,000	$/Customer Ranking
1	Ohio Power Company	1,467,725	79,284	12,296	66,988	$45.64	1
2	MidAmerican Energy Company	760,580	63,771	22,309	41,462	$54.51	2
3	Consumers Energy Company	1,806,511	142,178	42,379	99,799	$55.24	3
4	Duke Energy Ohio, Inc.	706,793	54,281	14,196	40,085	$56.71	4
5	Florida Power & Light Company	4,840,240	335,632	55,232	280,400	$57.93	5
6	Public Service Electric and Gas Company	2,227,066	192,577	57,948	134,629	$60.45	6
7	Jersey Central Power & Light Company	1,113,459	111,549	42,651	68,898	$61.88	7
8	Wisconsin Electric Power Company	1,143,041	134,459	55,113	79,346	$69.42	8
9	PacifiCorp	1,840,789	129,633	0	129,633	$70.42	9
10	Cleveland Electric Illuminating Company	747,747	79,371	25,099	54,272	$72.58	10
11	West Penn Power Company	723,352	58,699	6,091	52,608	$72.73	11
12	Ohio Edison Company	1,041,123	99,745	23,341	76,404	$73.39	12
13	Pennsylvania Electric Company	587,251	60,926	17,075	43,851	$74.67	13
14	Public Service Company of Colorado	1,441,981	165,928	53,442	112,486	$78.01	14
15	Metropolitan Edison Company	562,850	58,329	13,246	45,083	$80.10	15
16	Puget Sound Energy, Inc.	1,119,711	120,326	28,793	91,533	$81.75	16
17	Public Service Company of Oklahoma	547,142	55,328	10,592	44,736	$81.76	17
18	Nevada Power Company	903,132	99,466	23,605	75,861	$84.00	18
19	Commonwealth Edison Company	3,953,907	488,644	140,785	347,859	$87.98	19
20	Central Maine Power Company	610,335	55,417	1,606	53,811	$88.17	20
21	Appalachian Power Company	956,716	104,282	18,006	86,276	$90.18	21
22	DTE Electric Company	2,173,258	357,938	159,255	198,683	$91.42	22
23	PECO Energy Company	1,613,290	187,942	38,822	149,120	$92.43	23
24	Ameren Illinois Company	1,224,017	149,707	31,900	117,807	$96.25	24
25	Virginia Electric and Power Company	2,550,019	377,040	125,793	251,247	$98.53	25
26	Arizona Public Service Company	1,193,511	186,773	64,872	121,901	$102.14	26
27	Oklahoma Gas and Electric Company	830,057	141,320	55,665	85,655	$103.19	27
28	NSTAR Electric Company	1,202,407	162,571	33,540	129,031	$107.31	28
29	New York State Electric & Gas Corporation	889,166	96,599	916	95,683	$107.61	29
30	Baltimore Gas and Electric Company	1,268,995	190,297	51,499	138,798	$109.38	30
31	Southwestern Electric Power Company	532,652	75,617	16,722	58,895	$110.57	31
32	Dayton Power and Light Company	517,570	78,267	20,483	57,784	$111.64	32
33	Tampa Electric Company	730,504	123,403	35,580	87,823	$120.22	33
34	Duke Energy Florida, LLC	1,743,136	257,542	47,487	210,055	$120.50	34
35	Northern States Power Company - MN	1,454,287	265,532	88,142	177,390	$121.98	35
36	PPL Electric Utilities Corporation	1,426,676	201,744	21,384	180,360	$126.42	36
37	Consolidated Edison Company of New York, Inc.	3,419,697	866,797	431,840	434,957	$127.19	37
38	Georgia Power Company	2,468,872	472,842	146,299	326,543	$132.26	38
39	Kentucky Utilities Company	547,069	110,091	36,633	73,458	$134.28	39
40	Portland General Electric Company	859,397	176,471	57,374	119,097	$138.58	40
41	Duke Energy Carolinas, LLC	2,519,317	491,096	141,457	349,639	$138.78	41
42	Connecticut Light and Power Company	1,238,338	183,404	10,478	172,926	$139.64	42
43	Duke Energy Indiana, LLC	812,986	152,284	38,057	114,227	$140.50	43
44	Atlantic City Electric Company	548,442	92,346	12,071	80,275	$146.37	44
45	Indiana Michigan Power Company	589,041	114,698	27,428	87,270	$148.16	45
46	Union Electric Company	1,208,410	251,783	66,698	185,085	$153.16	46
47	Duquesne Light Company	592,977	120,524	29,426	91,098	$153.63	47
48	Public Service Company of New Hampshire	507,998	89,542	9,172	80,370	$158.21	48
49	Kansas City Power & Light Company	531,631	168,097	83,444	84,653	$159.23	49
50	Entergy Louisiana, LLC	1,070,249	284,408	108,630	175,778	$164.24	50
51	Delmarva Power & Light Company	516,709	100,113	15,230	84,883	$164.28	51
52	Southern California Edison Company	5,049,196	999,751	169,577	830,174	$164.42	52
53	Duke Energy Progress, LLC	1,534,394	340,666	87,327	253,339	$165.11	53
54	Entergy Arkansas, Inc.	706,879	185,467	66,829	118,638	$167.83	54
55	Niagara Mohawk Power Corporation	1,659,215	370,611	86,306	284,305	$171.35	55
56	Massachusetts Electric Company	1,294,180	294,710	66,626	228,084	$176.24	56
57	Potomac Electric Power Company	848,172	183,061	32,397	150,664	$177.63	57
58	Idaho Power Co.	529,901	146,887	52,679	94,208	$177.78	58
59	Pacific Gas and Electric Company	5,428,388	1,329,265	360,500	968,765	$178.46	59
60	South Carolina Electric & Gas Co.	705,025	191,727	55,383	136,344	$193.39	60
61	Alabama Power Company	1,468,744	387,122	71,750	315,372	$214.72	61
62	Public Service Company of New Mexico	517,739	149,173	26,995	122,178	$235.98	62
63	San Diego Gas & Electric Co.	1,430,175	400,172	32,701	367,471	$256.94	63

S&P Global Market Intelligence, 55 Water Street, New York, NY 10041
Columns c-e from S&P Global for regulated electric companies with more than 500,000 customers.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Uncollectible Accounts Expense Projection
for 2019
($000)

Case No.: U-20134
Exhibit No.: A-90 (DLH-4)
Page: 1 of 1
Witness: DLHarry
Date: May 2018

Line No.	(a) Year	(b) Gross Charge-Offs	(c) Less Recoveries	(d) Net Write-Offs	(e) Total Electric Service Revenue MPSC P-521 P. 304.1 col (c) + P. 305 col (c)	(f) BDLR col (d) / col (e)
1	2013	$ 52,616	$ 20,576	$ 32,040	$ 4,013,614	0.798%
2	2014	48,049	16,824	31,225	4,150,882	0.752%
3	2015	46,941	16,886	30,055	4,031,759	0.745%
4	2016	32,691	13,496	19,195	4,157,271	0.462%
5	2017	32,032	13,060	18,972	4,245,558	0.447%
6	3-Year Average	$ 37,221	$ 14,481	$ 22,741	$ 4,144,863	0.549%
7	5-Year Average	$ 42,466	$ 16,168	$ 26,297	$ 4,119,817	0.638%
8	Test Year Total Company Electric Revenues and Deliveries Exhibit A-15 (EMB-3), Schedule E-2, Page 1 of 1 Row 25, Column (k) - Row 25, Column (c)				$ 4,299,965	
9	3-Year Average BDLR				0.549%	
10	Sub-Total				$ 23,592	
11	Less Smart Grid Program Benefits				$ 4,997 [1]	
12	**Test Year Total Uncollectible Accounts Expense**				**$ 18,594**	

[1] Smart Grid Program Benefits:

Exhibit A-116 (LDW-3), Page 3, Line 34		
2019		$ 8,344
Less amounts included in prior year actual Net Write-offs		
2015	128	
2016	3,685	
2017	6,227	
Total	$ 10,040	
3-year average		3,347
Test Year Smart Grid Program Benefits		$ 4,997

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Injuries & Damages Expense
for the Years 2013 through 2019
($000)

Case No.: U-20134
Exhibit No.: A-91 (DLH-5)
Page: 1 of 1
Witness: DLHarry
Date: May 2018

Line No.	(a) Program Description		(b) 2013 Actual	(c) 2014 Actual	(d) 2015 Actual	(e) 2016 Actual	(f) 2017 Actual	(g) 2018 Projected	(h) 2019 Projected
1	Electric Injuries & Damages	[1]	$ 2,636	$ 4,382	$ 1,290	$ 3,111	$ 2,933	$ 3,000	$ 2,870
2	Internal Legal Costs	[2]	816	563	563	562	617	631	624
3	Workers' Compensation	[3]	1,242	1,737	1,115	870	937	959	1,180
4	Total Electric Injuries & Damages		**$ 4,694**	**$ 6,682**	**$ 2,968**	**$ 4,543**	**$ 4,487**	**$ 4,590**	**$ 4,675**

[1] Electric Injuries & Damages costs are 2013 - 2017 (actual expense) and escalated using the noted inflation factors below for 2018. 2019 test year based on a five-year average (2013 - 2017).

[2] Legal costs are 2013 - 2017 (actual expense) and escalated using the noted inflation factors below for 2018. 2019 test year based on a five-year average (2013 - 2017).

[3] Electric Workers' Compensation costs are 2013 - 2017 (actual expense) and escalated using the noted inflation factors below for 2018. 2019 test year based on a five-year average (2013 - 2017).

2017 Inflation Factor 2.1%
2018 Inflation Factor 2.3%
2019 Inflation Factor 1.7%

Source: February 2018 IHS Markit

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20134
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

LATINA D. JOHNSON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Schedule B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Operations Support
Summary of Actual and Projected Electric Capital Expenditures
for the years 2017, 2018, and 2019
($000)

Case No.: U-20134
Exhibit No.: A-12 (LDJ-1)
Schedule: B-5.2
Page: 1 of 1
Witness: LDJohnson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	**Projected Bridge Year**			**Projected Test Year**
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**24 Mos Ending 12/31/2019**	**12 Mos Ending 12/31/2019**
1	**Asset Preservation**	**$21,123**	**$20,693**	**$32,870**	**$53,563**	**$32,870**
2	Contractor	17,672	17,384	27,614	44,998	27,614
3	Labor	1,101	308	490	798	490
4	Materials	1,747	1,819	2,889	4,708	2,889
5	Business Expenses	63	43	69	112	69
6	Contingency	-	-	-	-	-
7	Other (Loadings, Chargebacks)	541	1,138	1,808	2,946	1,808
8	**Computer & Other Equipment**	**$373**	**$670**	**$670**	**$1,340**	**$670**
9	**Total Operations Support Capital**	**$21,496**	**$21,363**	**$33,540**	**$54,903**	**$33,540**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Operations Support O&M Expenses
for the years 2017, 2018, and 2019
($000)

Case No.: U-20134
Exhibit No.: A-92 (LDJ-2)
Page: 1 of 1
Witness: LDJohnson
Date: May 2018

	(a)	(b)	(c)	(d)	(e)
		Historical	**Projected**		
Line No.	**Description**	**12 Mos Ended 12/31/2017**	**12 Mos Ending 12/31/2018**	**12 Mos Ending 12/31/2019**	**Source**
1	Facilities	$ 10,711	$ 11,156	$ 11,156	
2	Real Estate	1,698	1,813	1,813	
3	Administrative Operations	1,894	1,728	1,728	
4	**Total Expense**	**$ 14,303**	**$ 14,697**	**$ 14,697**	

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20134

EXHIBITS

OF

SRI MADDIPATI

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2018

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (SM-1)
Schedule: D-5
Page: 1 of 13
Witness: SMaddipati
Date: May 2018

Proxy Companies

(a) Line No.	(b) Company	(c) Ticker	(d) Regulated Generation Capacity (MW)	(e) Net PP&E ($ Millions)	(f) NTM Payout Ratio >= 60%	(g) S&P IG Rated Bond?	(h) Moody's IG Rated Bond?
1	Alliant Energy Corporation	LNT	7,072	11,235	61%	✓	✓
2	Ameren Corporation	AEE	11,447	21,466	60%	✓	✓
3	American Electric Power Company, Inc.	AEP	24,630	50,262	64%	✓	✓
4	Dominion Energy, Inc.	D	23,392	53,758	82%	✓	✓
5	DTE Energy Company	DTE	12,274	20,721	62%	✓	✓
6	NiSource Inc.	NI	4,021	14,360	61%	✓	✓
7	OGE Energy Corp.	OGE	8,048	8,294	70%	✓	✓
8	Pinnacle West Capital Corporation	PNW	7,167	13,188	62%	✓	✓
9	Portland General Electric Company	POR	4,232	6,430	63%	✓	✓
10	WEC Energy Group, Inc.	WEC	10,000	21,347	67%	✓	✓
11	Xcel Energy Inc.	XEL	19,967	34,329	62%	✓	✓
12	Average		12,023	23,217	65%	✓	✓
13	Consumers Energy	CMS	5,759	15,877		✓	✓

Proxy Group Selection Criteria:

Regulated generation capacity must be greater than 2,000 MW.
Net Property Plant and Equipment ("PP&E") must be greater than $5 billion but less than $60 billion.
Next Twelve Months ("NTM") payout ratio must be greater than or equal to 60%.
Company must not be selling its business as a part of a corporate acquisition or be a restructuring entity.
Company must have Investment Grade ("IG") rated bonds.

Sources:

Columns (d) through (f): S&P Global Market Intelligence as of February 28, 2018.
Columns (g) and (h): Bloomberg as of February 28, 2018.

Consumers Energy Data: Column (d): Consumers Energy 2017 Form 10-K, page 21.
Column (e): Consumers Energy 2017 Form 10-K, page 100.

Schedule D-5

Capital Asset Pricing Model Application

Equation: $K_e = R_f + F + \beta \times (R_p)$

Where:

		Report	Date	Test Year Average		100% 2019			
K_e =	The annual required return on equity								
R_f =	The risk free rate	Global Insight	Mar 2018	3.95%	→	3.95%			
F =	The flotation cost adjustment					25%	25%	25%	25%
β =	The beta, or covariance, of the stock price to market					1Q 2019	2Q 2019	3Q 2019	4Q 2019
R_p =	The expected equity risk premium	Blue Chip	Mar 1, 2018	3.75%	→	3.60%	3.70%	3.80%	3.90%
							Estimated	Estimated	Estimated

Line No (a)	Company (b)	Ticker (c)	Current Beta (β) (d)	Flotation Cost Adjustment (F) (e)	Test Year Risk-Free Rate (R_f) (f)	1926-2016 Risk Premium (R_p) (g)	Test Year CAPM ROE (h)	1926-2016 Risk-Free Rate (R_f) (i)	Normalized CAPM ROE (j)	Projected Risk Premium (R_p) (k)	Projected Risk Premium CAPM ROE (l)
1	Alliant Energy Corporation	LNT	0.70	0.17%	3.85%	7.07%	8.97%	4.99%	**10.11%**	11.46%	**12.04%**
2	Ameren Corporation	AEE	0.65	0.17%	3.85%	7.07%	8.60%	4.99%	**9.74%**	11.46%	**11.45%**
3	American Electric Power Company, Inc.	AEP	0.65	0.19%	3.85%	7.07%	8.63%	4.99%	**9.77%**	11.46%	**11.48%**
4	Dominion Energy, Inc.	D	0.65	0.21%	3.85%	7.07%	8.65%	4.99%	**9.79%**	11.46%	**11.50%**
5	DTE Energy Company	DTE	0.65	0.17%	3.85%	7.07%	8.60%	4.99%	**9.75%**	11.46%	**11.45%**
6	NiSource Inc.	NI	0.60	0.17%	3.85%	7.07%	8.26%	4.99%	**9.40%**	11.46%	**10.89%**
7	OGE Energy Corp.	OGE	0.95	0.21%	3.85%	7.07%	10.78%	4.99%	**11.92%**	11.46%	**14.95%**
8	Pinnacle West Capital Corporation	PNW	0.70	0.18%	3.85%	7.07%	8.98%	4.99%	**10.12%**	11.46%	**12.05%**
9	Portland General Electric Company	POR	0.70	0.17%	3.85%	7.07%	8.97%	4.99%	**10.11%**	11.46%	**12.04%**
10	WEC Energy Group, Inc.	WEC	0.60	0.18%	3.85%	7.07%	8.27%	4.99%	**9.41%**	11.46%	**10.90%**
11	Xcel Energy Inc.	XEL	0.60	0.16%	3.85%	7.07%	8.25%	4.99%	**9.40%**	11.46%	**10.89%**
12	**Average**		0.68						**9.96%**		**11.78%**
13	**Minimum**		0.60						**9.40%**		**10.89%**
14	**Maximum**		0.95						**11.92%**		**14.95%**

Inconsistent use of current R_f with Historical Premium

Sources:
Column (d): Beta per Value Line. PNW, POR, and XEL as of January 26, 2018. D as of February 16, 2018. NI as of March 2, 2018. LNT, AEE, AEP, DTE, OGE, and WEC as of March 16, 2018.
Column (e): Exhibit A-14 (SM-1), Schedule D-5, page 5.
Column (f): Average of Global Insight U.S. Economic Outlook (Mar 2018) and Blue Chip (Mar 1, 2018).
Columns (g) and (i): Exhibit A-14 (SM-1), Schedule D-5, page 9, line 51.
Column (h) = Column (e) + Column (f) + Column (d) x Column (g).
Column (j) = Column (e) + Column (i) + Column (d) x Column (g).
Column (k): Exhibit A-14 (SM-1), Schedule D-5, page 3.
Column (l) = Column (e) + Column (f) + Column (d) x Column (k).

Notes:
Normalized CAPM ROE uses the 1926-2017 risk-free rate and corresponding risk premium.
Projected Risk Premium CAPM ROE uses the test year risk-free rate and projected risk premium.

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Empirical Capital Asset Pricing Model Application

Case No.:	U-20134
Exhibit No.:	A-14 (SM-1)
Schedule:	D-5
Page:	3 of 13
Witness:	SMaddipati
Date:	May 2018

Equation: $K_e = R_f + \alpha + F + \beta \times (R_p - \alpha)$

Where:
- K_e = The annual required return on equity
- R_f = The risk free rate
- α = The alpha of the risk-return line
- F = The flotation cost adjustment
- β = The beta, or covariance of the stock price to market
- R_p = The expected equity risk premium

Projected Risk Premium

Risk Premium During Most Recent Low Interest Rates (2011-2017) (Exhibit A-14 (SM-1), Schedule D-5, page 10)	11.34%
Risk Premium During Federal Reserve Action (1942-1951 & 2011-2017) (Exhibit A-14 (SM-1), Schedule D-5, page 10)	13.91%
S&P 500 Implied Risk Premium (Exhibit A-14 (SM-1), Schedule D-5, page 13)	8.58%
Federal Reserve research	12.00%
Average Projected Risk Premium	**11.46%**

(a) Line No.	(b) Company	(c) Ticker	(d) Current Beta (β)	(e) Alpha (α)	(f) Flotation Cost Adjustment (F)	(g) Test Year Risk-Free Rate (R_f)	(h) 1926-2016 Risk Premium (R_P)	(i) Proxy Co ECAPM ROE	(j) 1926-2016 Risk-Free Rate (R_f)	(k) Normalized ECAPM ROE	(l) Projected Risk Premium (R_P)	(m) Projected Risk Premium ECAPM ROE
1	Alliant Energy Corporation	LNT	0.70	1.50%	0.17%	3.85%	7.07%	9.42%	4.99%	**10.56%**	11.46%	**12.49%**
2	Ameren Corporation	AEE	0.65	1.50%	0.17%	3.85%	7.07%	9.13%	4.99%	**10.27%**	11.46%	**11.97%**
3	American Electric Power Company, Inc.	AEP	0.65	1.50%	0.19%	3.85%	7.07%	9.16%	4.99%	**10.30%**	11.46%	**12.01%**
4	Dominion Energy, Inc.	D	0.65	1.50%	0.21%	3.85%	7.07%	9.17%	4.99%	**10.32%**	11.46%	**12.03%**
5	DTE Energy Company	DTE	0.65	1.50%	0.17%	3.85%	7.07%	9.13%	4.99%	**10.27%**	11.46%	**11.98%**
6	NiSource Inc.	NI	0.60	1.50%	0.17%	3.85%	7.07%	8.86%	4.99%	**10.00%**	11.46%	**11.49%**
7	OGE Energy Corp.	OGE	0.95	1.50%	0.21%	3.85%	7.07%	10.85%	4.99%	**11.99%**	11.46%	**15.02%**
8	Pinnacle West Capital Corporation	PNW	0.70	1.50%	0.18%	3.85%	7.07%	9.43%	4.99%	**10.57%**	11.46%	**12.50%**
9	Portland General Electric Company	POR	0.70	1.50%	0.17%	3.85%	7.07%	9.42%	4.99%	**10.56%**	11.46%	**12.49%**
10	WEC Energy Group, Inc.	WEC	0.60	1.50%	0.18%	3.85%	7.07%	8.87%	4.99%	**10.01%**	11.46%	**11.50%**
11	Xcel Energy Inc.	XEL	0.60	1.50%	0.16%	3.85%	7.07%	8.85%	4.99%	**10.00%**	11.46%	**11.49%**
12	**Average**		0.68		0.18%					**10.44%**		**12.27%**
13	**Minimum**		0.60		0.16%					**10.00%**		**11.49%**
14	**Maximum**		0.95		0.21%					**11.99%**		**15.02%**

Inconsistent use of current R_f with Historical Premium

Sources:
- Columns (d), (g), (h), (i), and (l): Exhibit A-14 (SM-1), Schedule D-5, page 2.
- Column (e): Alpha, mid-point of reasonable range of 1% to 2% cited by Roger A. Morin, "New Regulatory Finance" (2006).
- Column (f): Exhibit A-14 (SM-1), Schedule D-5, page 2.
- Column (i) = Column (g) + Column (e) + Column (f) + Column (d) x (Column (h) - Column (e)).
- Column (k) = Column (j) + Column (e) + Column (f) + Column (d) x (Column (h) - Column (e)).
- Column (m) = Column (g) + Column (e) + Column (f) + Column (d) x (Column (l) - Column (e)).

Notes:
- Normalized ECAPM ROE uses the 1926-2017 risk-free rate and corresponding risk premium.
- Projected Risk Premium ECAPM ROE uses the test year risk-free rate and projected risk premium.

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (SM-1)
Schedule: D-5
Page: 4 of 13
Witness: SMaddipati
Date: May 2018

Risk Premium Analysis Over Utility Bonds

(a)	(b)	(c)	(d)	(e)	(f)
Line		S&P Bond Rating			
No.	**Description**	**A**	**A-**	**BBB+**	**BBB**
	Normalized Risk Premium Analysis (Consistent Use of Historical Spread and Historical Rates)				
1	Historical Spread of Electric Utility Common Stock Over Utility Bonds	4.44%	4.44%	4.44%	4.44%
2	Historical Long-Term Government Bond Return	4.99%	4.99%	4.99%	4.99%
3	Corporate Spread	1.07%	1.19%	1.32%	1.90%
4	Current Estimated Bond Yield (Lines 2 + 3)	6.07%	6.18%	6.31%	6.89%
5	Cost of Equity (Lines 1 + 4)	10.50%	10.62%	10.74%	11.33%
6	**Average**				**10.80%**
7	**Minimum**				**10.50%**
8	**Maximum**				**11.33%**
	Projected Risk Premium Analysis (Appropriate Use of Projected Spread and Projected Long-Term Bond Rates)				
9	Spread of Electric Utility Common Stock Over Utility Bonds During Low Interest Rate Period	8.04%	8.04%	8.04%	8.04%
10	Projected Long-Term Government Bond Return	3.85%	3.85%	3.85%	3.85%
11	Corporate Spread	1.07%	1.19%	1.32%	1.90%
12	Current Estimated Bond Yield (Lines 10 + 11)	4.92%	5.04%	5.17%	5.75%
13	Cost of Equity (Lines 9 + 12)	12.97%	13.08%	13.21%	13.79%
14	**Average**				**13.26%**
15	**Minimum**				**12.97%**
16	**Maximum**				**13.79%**

Sources: Line 1: Exhibit A-14 (SM-1), Schedule D-5, page 10, line 87.
Line 2: Exhibit A-14 (SM-1), Schedule D-5, page 9, line 51.
Line 3 and 11: Exhibit A-81 (AJD-9), page 3, lines 107-110.
Line 9: Exhibit A-14 (SM-1), Schedule D-5, page 10, line 89.
Line 10: Exhibit A-14 (SM-1), Schedule D-5, page 2, test year risk-free rate (R_f).

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (SM-1)
Schedule: D-5
Page: 5 of 13
Witness: SMaddipati
Date: May 2018

Discounted Cash Flow ("DCF") Model Application

Equation: $K_e = D_1 / P_0 + g + F$

Where:
K_e = Annual required rate of return on equity
D_1 = Expected annual dividend per share at the end of first year.
P_0 = Current price of stock
g = Growth rate
F = Flotation cost adjustment

Primary Discounted Cash Flow ("DCF") Model

(a) Line No.	(b) Company	(c) Ticker	(d) Avg of 30-day Closing $	(e) Last Qtrly Dividend Payment	(f) Current Annual Div (D_0)	(g) Current Dividend Yield	(h) Flotation Cost Adjust. (F)	(i) Number of Analyst Estimates	(j) Consensus Analyst Growth (%)	(k) Expected Dividend Yield	(l) Analyst Consensus DCF ROE	(m) Mid-point Company Guidance (%)	(n) Expected Dividend Yield	(o) Company Guidance DCF ROE
1	Alliant Energy Corporation	LNT	38.67	0.3360	1.34	3.48%	0.17%	4	6.1%	3.69%	**10.00%**	6.0%	3.68%	**9.86%**
2	Ameren Corporation	AEE	54.90	0.4575	1.83	3.33%	0.17%	3	5.3%	3.51%	**8.99%**	6.0%	3.53%	**9.70%**
3	American Electric Power Company, Inc.	AEP	66.07	0.6200	2.48	3.75%	0.19%	4	5.0%	3.94%	**9.13%**	6.0%	3.98%	**10.17%**
4	Dominion Energy, Inc.	D	74.79	0.7700	3.08	4.12%	0.21%	4	9.4%	4.50%	**14.07%**	10.0%	4.53%	**14.74%**
5	DTE Energy Company	DTE	102.23	0.8825	3.53	3.45%	0.17%	7	6.4%	3.68%	**10.28%**	7.0%	3.69%	**10.87%**
6	NiSource Inc.	NI	23.34	0.1950	0.78	3.34%	0.17%	4	7.3%	3.59%	**11.09%**	6.0%	3.54%	**9.71%**
7	OGE Energy Corp.	OGE	31.19	0.3330	1.33	4.27%	0.21%	1	8.2%	4.62%		10.0%	4.70%	
8	Pinnacle West Capital Corporation	PNW	77.24	0.6950	2.78	3.60%	0.18%	5	6.1%	3.82%	**10.08%**	6.5%	3.83%	**10.51%**
9	Portland General Electric Company	POR	40.57	0.3400	1.36	3.35%	0.17%	5	6.1%	3.56%	**9.81%**	6.1%	3.56%	**9.81%**
10	WEC Energy Group, Inc.	WEC	61.09	0.5530	2.21	3.62%	0.18%	5	6.3%	3.85%	**10.30%**	6.0%	3.84%	**10.02%**
11	Xcel Energy Inc.	XEL	43.85	0.3600	1.44	3.28%	0.16%	4	5.7%	3.47%	**9.32%**	6.0%	3.48%	**9.64%**
12	**Average**						0.18%				**10.31%**			**10.50%**
13	**Minimum**						0.16%				**8.99%**			**9.64%**
14	**Maximum**						0.21%				**14.07%**			**14.74%**

Sources:

Column (d): Factset from Jan 31, 2018 through Feb 28, 2018.
Column (e): Yahoo! Finance as of Feb 28, 2018.
Column (f) = 4 x Column (e).
Column (g) = Column (f) / Column (d).
Column (h): Flotation cost adjustment of 5% of current dividend yield, as described by Roger A. Morin, "New Regulatory Finance" (2006).
Column (i): Number of Factset 3-year consensus analyst Dividend per Share ("DPS") growth estimate as of Feb 28, 2018.
Column (j): 3-year consensus analyst DPS growth estimate as of Feb 28, 2018.
Column (k) = Column (g) x (1 + Column (j)).
Column (l) = Column (h) + Column (j) + Column (k).
Column (m): AEP, D, DTE, NI, OGE, WEC, and XEL company dividend guidance. LNT and AEE company earnings guidance. PNW rate base guidance. POR calculated Factset 3-year consensus analyst DPS growth estimates.
Column (n) = Column (g) x (1 + Column (m)).
Column (o) = Column (h) + Column (m) + Column (n).

Note:

OGE excluded from primary analysis due to lack of minimum quantity of three analyst estimates.

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (SM-1)
Schedule: D-5

Witness: SMaddipati
Date: May 2018

Comparable Earnings Analysis

(a)	(b)	(c)	(d)	(e)	(f)	(g)
					2021-2023	
Line No.	**Company**	**Ticker**	**Current Beta (β)**	**Earnings Per Share**	**Book Value Per Share**	**Implied ROE**
1	Alliant Energy Corporation	LNT	0.70	2.60	22.85	**11.38%**
2	Ameren Corporation	AEE	0.65	3.75	37.25	**10.07%**
3	American Electric Power Company, Inc.	AEP	0.65	5.00	46.75	**10.70%**
4	Dominion Energy, Inc.	D	0.65	5.25	32.00	**16.41%**
5	DTE Energy Company	DTE	0.65	7.50	68.50	**10.95%**
6	NiSource Inc.	NI	0.60	1.80	15.00	**12.00%**
7	OGE Energy Corp.	OGE	0.95	2.50	22.50	**11.11%**
8	Pinnacle West Capital Corporation	PNW	0.70	5.25	51.75	**10.14%**
9	Portland General Electric Company	POR	0.70	3.00	31.75	**9.45%**
10	WEC Energy Group, Inc.	WEC	0.60	4.25	35.50	**11.97%**
11	Xcel Energy Inc.	XEL	0.60	2.75	26.25	**10.48%**
12	**Average**					**11.33%**
13	**Minimum**					**9.45%**
14	**Maximum**					**16.41%**

Sources: Columns (d), (e), and (f): data per Value Line. PNW, POR, and XEL as of January 26, 2018. D as of February 16, 2018. NI as of March 2, 2018. LNT, AEE, AEP, DTE, OGE, and WEC as of March 16, 2018.
Column (g) = Column (e) / Column (f).

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
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Case No.: U-20134
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Consensus Analyst Estimates of Earned ROE %

(a) Line No.	(b) **Company**	(c) **Ticker**	(d) **2019 Earned ROE %**
1	Alliant Energy Corporation	LNT	**10.79**
2	Ameren Corporation	AEE	**10.15**
3	American Electric Power Company, Inc.	AEP	**10.63**
4	Dominion Energy, Inc.	D	**14.04**
5	DTE Energy Company	DTE	**10.50**
6	NiSource Inc.	NI	**9.31**
7	OGE Energy Corp.	OGE	**9.95**
8	Pinnacle West Capital Corporation	PNW	**9.90**
9	Portland General Electric Company	POR	**8.56**
10	WEC Energy Group, Inc.	WEC	**11.07**
11	Xcel Energy Inc.	XEL	**10.73**
12	**Average**		**10.51%**
13	**Minimum**		**8.56%**
14	**Maximum**		**14.04%**

Source: Consensus analyst estimates of earned ROE as of February 28, 2018.

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (SM-1)
Schedule: D-5

Witness: SMaddipati
Date: May 2018

Cumulative Annual Interest Savings

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.			**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Total**
1	S&P Senior Secured Debt Credit Rating		BBB-	BBB	BBB	BBB	BBB+	BBB+	BBB+	A-	A	A	A	A	
2	Debt Issued - First Mortgage Bonds ($ millions)	A		$ -	$ 600	$ 500	$ 600	$ -	$ 725	$ 750	$ 500	$ 250	$ 450	$ 535	$ 4,910
3	Interest Spread Differential vs. BBB-	B		1.31%	1.31%	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	
4	Annual Interest Savings ($ millions)	A * B		$ -	$ 8	$ 7	$ 6	$ -	$ 9	$ 6	$ 4	$ 1	$ 3	$ 3	
5	Cumulative Annual Interest Savings ($ millions)			$ -	$ 8	$ 14	$ 20	$ 20	$ 29	$ 35	$ 39	$ 41	$ 44	$ 47	**$ 47**

Annual savings repeats going forward

(a)	(b)	(c)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
6	BBB- Rating Issuance Spread	C	NA	NA	NMF	4.40%	2.17%	2.55%	2.47%	1.71%	1.69%	1.63%	1.83%	1.47%
7	Current Rating Issuance Spread	D	NA	NA	NMF	3.09%	1.24%	1.56%	1.24%	0.90%	0.87%	1.11%	1.11%	0.86%
8	Issuance Spread Differential vs. BBB-	C - D	-	-	-	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%

Source: All issuance spreads per the Barclays Bank Utility Deal listing.
Line 3: Annual average fixed rate issuance spread versus BBB-.
Line 6: Average fixed rate BBB- issuance spread.
Line 7: Average fixed rate issuance spread for current ratings.
Line 8: Average issuance spread differential for current ratings versus BBB-.

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION		Case No.:	U-20134
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CAPM Risk Premium Analysis

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	**Period**	**Large Company Total Returns**	**Long-Term Gov Bonds Income Returns**	**Difference**	**Period**	**Large Company Total Returns**	**Long-Term Gov Bonds Income Returns**	**Difference**
1	1926	11.62%	3.73%	7.89%	1976	23.93%	7.89%	16.04%
2	1927	37.49%	3.41%	34.08%	1977	-7.16%	7.14%	-14.30%
3	1928	43.61%	3.22%	40.39%	1978	6.57%	7.90%	-1.33%
4	1929	-8.42%	3.47%	-11.89%	1979	18.61%	8.86%	9.75%
5	1930	-24.90%	3.32%	-28.22%	1980	32.50%	9.97%	22.53%
6	1931	-43.34%	3.33%	-46.67%	1981	-4.92%	11.55%	-16.47%
7	1932	-8.19%	3.69%	-11.88%	1982	21.55%	13.50%	8.05%
8	1933	53.99%	3.12%	50.87%	1983	22.56%	10.38%	12.18%
9	1934	-1.44%	3.18%	-4.62%	1984	6.27%	11.74%	-5.47%
10	1935	47.67%	2.81%	44.86%	1985	31.73%	11.25%	20.48%
11	1936	33.92%	2.77%	31.15%	1986	18.67%	8.98%	9.69%
12	1937	-35.03%	2.66%	-37.69%	1987	5.25%	7.92%	-2.67%
13	1938	31.12%	2.64%	28.48%	1988	16.61%	8.97%	7.64%
14	1939	-0.41%	2.40%	-2.81%	1989	31.69%	8.81%	22.88%
15	1940	-9.78%	2.23%	-12.01%	1990	-3.10%	8.19%	-11.29%
16	1941	-11.59%	1.94%	-13.53%	1991	30.47%	8.22%	22.25%
17	1942	20.34%	2.46%	17.88%	1992	7.62%	7.26%	0.36%
18	1943	25.90%	2.44%	23.46%	1993	10.08%	7.17%	2.91%
19	1944	19.75%	2.46%	17.29%	1994	1.32%	6.59%	-5.27%
20	1945	36.44%	2.34%	34.10%	1995	37.58%	7.60%	29.98%
21	1946	-8.07%	2.04%	-10.11%	1996	22.96%	6.18%	16.78%
22	1947	5.71%	2.13%	3.58%	1997	33.36%	6.64%	26.72%
23	1948	5.50%	2.40%	3.10%	1998	28.58%	5.83%	22.75%
24	1949	18.79%	2.25%	16.54%	1999	21.04%	5.57%	15.47%
25	1950	31.71%	2.12%	29.59%	2000	-9.10%	6.50%	-15.60%
26	1951	24.02%	2.38%	21.64%	2001	-11.89%	5.53%	-17.42%
27	1952	18.37%	2.66%	15.71%	2002	-22.10%	5.59%	-27.69%
28	1953	-0.99%	2.84%	-3.83%	2003	28.68%	4.80%	23.88%
29	1954	52.62%	2.79%	49.83%	2004	10.88%	5.02%	5.86%
30	1955	31.56%	2.75%	28.81%	2005	4.91%	4.69%	0.22%
31	1956	6.56%	2.99%	3.57%	2006	15.79%	4.68%	11.11%
32	1957	-10.78%	3.44%	-14.22%	2007	5.49%	4.86%	0.63%
33	1958	43.36%	3.27%	40.09%	2008	-37.00%	4.45%	-41.45%
34	1959	11.96%	4.01%	7.95%	2009	26.46%	3.47%	22.99%
35	1960	0.47%	4.26%	-3.79%	2010	15.06%	4.25%	10.81%
36	1961	26.89%	3.83%	23.06%	2011	2.11%	3.82%	-1.71%
37	1962	-8.73%	4.00%	-12.73%	2012	16.00%	2.46%	13.54%
38	1963	22.80%	3.89%	18.91%	2013	32.39%	2.88%	29.51%
39	1964	16.48%	4.15%	12.33%	2014	13.69%	3.41%	10.28%
40	1965	12.45%	4.19%	8.26%	2015	1.38%	2.47%	-1.09%
41	1966	-10.06%	4.49%	-14.55%	2016	11.96%	2.30%	9.66%
42	1967	23.98%	4.59%	19.39%	2017	21.83%	2.67%	19.16%
43	1968	11.06%	5.50%	5.56%				
44	1969	-8.50%	5.95%	-14.45%				
45	1970	3.86%	6.74%	-2.88%				
46	1971	14.30%	6.32%	7.98%				
47	1972	18.99%	5.87%	13.12%				
48	1973	-14.69%	6.51%	-21.20%				
49	1974	-26.47%	7.27%	-33.74%				
50	1975	37.23%	7.99%	29.24%				
51					**1926-2017 Average:**	**12.06%**	**4.99%**	**7.07%**
52							**Equity Risk Premium:**	**7.07%**
53					**1942-1951 Average**	**18.01%**	**2.30%**	**15.71%**
54							**Equity Risk Premium:**	**15.71%**
55					**2011-2017 Average:**	**14.19%**	**2.86%**	**11.34%**
56							**Equity Risk Premium:**	**11.34%**
57					**Low Interest Period, 1942-1951 & 2011-2017 Average:**	**16.44%**	**2.53%**	**13.91%**
58							**Equity Risk Premium:**	**13.91%**

Source: Columns (b), (c), (d), (f), (g), and (h): 2018 Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook, Roger Ibbotson, *et al.*
Column (e) = Column (c) - Column (d).
Column (i) = Column (g) - Column (h).

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Moody's Electric Utility Common Stocks					Yields on "A" Rated	Stock Spread Over
Line No.	Year	Year End Avg Pr/Sh	Average Div/Share	% Gain	Dividend Yield	Total Return	Utility Bonds (Year End)	"A" Rated Bond Yields
1	1931	43.23	3.47					
2	1932	39.42	2.63	-8.81%	6.08%	-2.73%	5.85%	-8.58%
3	1933	28.73	1.95	-27.12%	4.95%	-22.17%	7.22%	-29.39%
4	1934	21.06	1.60	-26.70%	5.57%	-21.13%	5.36%	-26.49%
5	1935	36.06	1.32	71.23%	6.27%	77.49%	4.29%	73.20%
6	1936	41.60	1.48	15.36%	4.10%	19.47%	3.83%	15.64%
7	1937	24.24	1.74	-41.73%	4.18%	-37.55%	4.03%	-41.58%
8	1938	27.55	1.50	13.66%	6.19%	19.84%	3.74%	16.10%
9	1939	28.85	1.48	4.72%	5.37%	10.09%	3.38%	6.71%
10	1940	22.22	1.54	-22.98%	5.34%	-17.64%	3.10%	-20.74%
11	1941	13.45	1.44	-39.47%	6.48%	-32.99%	3.06%	-36.05%
12	1942	14.29	1.26	6.25%	9.37%	15.61%	3.06%	12.55%
13	1943	21.01	1.28	47.03%	8.96%	55.98%	2.99%	52.99%
14	1944	21.09	1.31	0.38%	6.24%	6.62%	2.97%	3.65%
15	1945	31.14	1.30	47.65%	6.16%	53.82%	2.75%	51.07%
16	1946	32.71	1.43	5.04%	4.59%	9.63%	2.76%	6.87%
17	1947	25.60	1.56	-21.74%	4.77%	-16.97%	3.05%	-20.02%
18	1948	26.20	1.60	2.34%	6.25%	8.59%	3.06%	5.53%
19	1949	30.57	1.66	16.68%	6.34%	23.02%	2.78%	20.24%
20	1950	30.81	1.76	0.79%	5.76%	6.54%	2.86%	3.68%
21	1951	33.85	1.88	9.87%	6.10%	15.97%	3.29%	12.68%
22	1952	37.85	1.91	11.82%	5.64%	17.46%	3.22%	14.24%
23	1953	39.61	2.01	4.65%	5.31%	9.96%	3.38%	6.58%
24	1954	47.56	2.13	20.07%	5.38%	25.45%	3.11%	22.34%
25	1955	49.35	2.21	3.76%	4.65%	8.41%	3.35%	5.06%
26	1956	48.96	2.32	-0.79%	4.70%	3.91%	3.91%	0.00%
27	1957	50.30	2.43	2.74%	4.96%	7.70%	4.36%	3.34%
28	1958	66.37	2.50	31.95%	4.97%	36.92%	4.49%	32.43%
29	1959	65.77	2.61	-0.90%	3.93%	3.03%	4.96%	-1.93%
30	1960	76.82	2.68	16.80%	4.07%	20.88%	4.65%	16.23%
31	1961	99.32	2.81	29.29%	3.66%	32.95%	4.65%	28.30%
32	1962	96.49	2.97	-2.85%	2.99%	0.14%	4.44%	-4.30%
33	1963	102.31	3.21	6.03%	3.33%	9.36%	4.46%	4.90%
34	1964	115.54	3.43	12.93%	3.35%	16.28%	4.54%	11.74%
35	1965	114.86	3.86	-0.59%	3.34%	2.75%	4.83%	-2.08%
36	1966	105.99	4.11	-7.72%	3.58%	-4.14%	5.67%	-9.81%
37	1967	98.19	4.34	-7.36%	4.09%	-3.26%	6.67%	-9.93%
38	1968	104.04	4.50	5.96%	4.58%	10.54%	6.87%	3.67%
39	1969	84.62	4.61	-18.67%	4.43%	-14.23%	8.59%	-22.82%
40	1970	88.59	4.70	4.69%	5.55%	10.25%	8.48%	1.77%
41	1971	85.56	4.77	-3.42%	5.38%	1.96%	7.90%	-5.94%
42	1972	83.61	4.87	-2.28%	5.69%	3.41%	7.48%	-4.07%
43	1973	60.87	5.01	-27.20%	5.99%	-21.21%	8.24%	-29.45%
44	1974	41.17	4.83	-32.36%	7.93%	-24.43%	10.27%	-34.70%
45	1975	55.66	4.97	35.20%	12.07%	47.27%	10.11%	37.16%
46	1976	66.29	5.18	19.10%	9.31%	28.40%	8.62%	19.78%
47	1977	68.19	5.54	2.87%	8.36%	11.22%	8.64%	2.58%
48	1978	59.75	5.81	-12.38%	8.52%	-3.86%	9.70%	-13.56%
49	1979	56.41	6.22	-5.59%	10.41%	4.82%	11.79%	-6.97%
50	1980	54.42	6.58	-3.53%	11.66%	8.14%	14.63%	-6.49%
51	1981	57.20	6.99	5.11%	12.84%	17.95%	16.29%	1.66%
52	1982	70.26	7.43	22.83%	12.99%	35.82%	14.43%	21.39%
53	1983	72.03	7.87	2.52%	11.20%	13.72%	13.52%	0.20%
54	1984	80.16	8.26	11.29%	11.47%	22.75%	13.11%	9.64%
55	1985	94.98	8.61	18.49%	10.74%	29.23%	10.97%	18.26%
56	1986	113.66	8.89	19.67%	9.36%	29.03%	9.12%	19.91%
57	1987	94.24	9.12	-17.09%	8.02%	-9.06%	10.98%	-20.04%
58	1988	100.94	8.87	7.11%	9.41%	16.52%	10.06%	6.46%
59	1989	122.52	8.82	21.38%	8.74%	30.12%	9.44%	20.68%
60	1990	117.77	8.79	-3.88%	7.17%	3.30%	9.73%	-6.43%
61	1991	144.02	8.95	22.29%	7.60%	29.89%	8.88%	21.01%
62	1992	141.06	9.05	-2.06%	6.28%	4.23%	8.43%	-4.20%
63	1993	146.70	8.99	4.00%	6.37%	10.37%	7.34%	3.03%
64	1994	115.50	8.96	-21.27%	6.11%	-15.16%	8.76%	-23.92%
65	1995	142.90	9.02	23.72%	7.81%	31.53%	7.23%	24.30%
66	1996	136.00	9.06	-4.83%	6.34%	1.51%	7.59%	-6.08%
67	1997	155.73	9.06	14.51%	6.66%	21.17%	7.16%	14.01%
68	1998	181.84	7.83	16.77%	5.03%	21.79%	6.91%	14.88%
69	1999	137.30	8.10	-24.49%	4.45%	-20.04%	8.14%	-28.18%
70	2000	227.09	8.27	65.40%	6.02%	71.42%	7.84%	63.58%
71	2001	200.50	8.69	-11.71%	3.83%	-7.88%	7.83%	-15.71%
72	2002	169.50	9.13	-15.46%	4.55%	-10.91%	6.93%	-17.84%
73	2003					25.74%	5.78%	19.95%
74	2004					26.34%	5.46%	20.88%
75	2005					19.62%	5.56%	14.06%
76	2006					19.83%	5.83%	14.00%
77	2007					20.59%	6.06%	14.53%
78	2008					-27.06%	5.99%	-33.04%
79	2009					8.73%	5.88%	2.85%
80	2010					4.83%	5.64%	-0.81%
81	2011					19.67%	4.09%	15.58%
82	2012					0.80%	3.95%	-3.16%
83	2013					11.20%	4.75%	6.45%
84	2014					29.67%	3.94%	25.73%
85	2015					-4.48%	4.39%	-8.87%
86	2016					16.54%	4.22%	12.32%
87	2017					11.98%	3.75%	8.23%
88					**1932-2017 Average:**	**10.85%**	**6.41%**	**4.44%**
89					**1942-1951 Average:**	**17.88%**	**2.96%**	**14.92%**
90					**2011-2017 Average:**	**12.20%**	**4.16%**	**8.04%**
91					**Low Interest Period, 1942-1951 & 2011-2017 Average:**	**15.54%**	**3.45%**	**12.09%**

Sources: Columns (b) and (c): Mergent Public Utility Manual. Per Moody's & Mergent, Moody's Electric Utility Index is no longer maintained.
Column (d) = (current year Column (b) - prior year Column (b)) / prior year Column (b).
Column (e) = current year Column (c) / prior year Column (b).
Column (f) = Column (d) + Column (e). For 2003 - 2017, the total return is the average of the total returns from Bloomberg for the S&P 500 Utilities & Electric Utilities Index and the Dow Jones Utilities Index (See Exhibit A-14 (SM-1), Schedule D-5, page 11).
Column (g): 1932 - 2002 Mergent Public Utility Manual; 2003 - 2017 Bloomberg.
Column (h) = Column (f) - Column (g).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (SM-1)
Schedule: D-5

Witness: SMaddipati
Date: May 2018

Utility Index Total Returns

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		S&P 500 Electric Utilities Index			**S&P 500 Utilities Index**			**Dow Jones Utilities Index**			**Average**
Line No.	**Year**	**Dec 31 Price**	**Dividends**	**Total Return**	**Dec 31 Price**	**Dividends**	**Total Return**	**Dec 31 Price**	**Dividends**	**Total Return**	**Total Return**
	2000	179.91			216.03			412.16			
1	2001	144.69	5.620	-16.45%	145.88	5.376	-29.98%	293.94	11.698	-25.84%	-24.09%
2	2002	117.42	5.843	-14.81%	97.76	5.036	-29.53%	215.18	11.411	-22.91%	-22.42%
3	2003	139.72	5.093	23.33%	118.39	4.254	25.45%	266.90	9.446	28.43%	25.74%
4	2004	170.17	5.721	25.89%	141.60	4.789	23.65%	334.95	10.668	29.49%	26.34%
5	2005	193.16	6.655	17.42%	159.66	5.511	16.65%	405.11	12.886	24.79%	19.62%
6	2006	229.94	6.991	22.66%	186.60	5.841	20.53%	456.77	14.331	16.29%	19.83%
7	2007	274.48	7.853	22.79%	216.11	6.175	19.12%	532.53	14.972	19.86%	20.59%
8	2008	196.27	8.570	-25.37%	147.93	6.632	-28.48%	370.76	16.281	-27.32%	-27.06%
9	2009	193.33	8.799	2.99%	157.99	6.652	11.30%	398.01	16.883	11.90%	8.73%
10	2010	190.39	9.067	3.17%	159.34	6.845	5.19%	404.99	17.402	6.13%	4.83%
11	2011	219.63	9.547	20.37%	182.98	7.301	19.42%	464.68	18.134	19.22%	19.67%
12	2012	208.67	9.774	-0.54%	177.66	7.655	1.28%	453.09	19.256	1.65%	0.80%
13	2013	215.55	9.515	7.86%	193.21	7.782	13.13%	490.57	19.675	12.61%	11.20%
14	2014	271.96	9.429	30.54%	240.14	7.976	28.42%	618.08	19.965	30.06%	29.67%
15	2015	247.30	9.802	-5.46%	220.00	8.418	-4.88%	577.82	21.085	-3.10%	-4.48%
16	2016	274.98	10.324	15.37%	246.83	8.782	16.19%	659.61	22.668	18.08%	16.54%
17	2017	293.61	10.575	10.62%	267.37	9.209	12.05%	723.37	23.767	13.27%	11.98%

Sources: Columns (c), (d), (f), (g), (i), and (j): Bloomberg.
Column (e) = (Column (c(t)) - Column (c(t-1)) + Column (d(t))) / Column (c(t-1)).
Column (h) = (Column (f(t)) - Column (f(t-1)) + Column (g(t))) / Column (f(t-1)).
Column (k) = (Column (i(t)) - Column (i(t-1)) + Column (j(t))) / Column (i(t-1)).
Column (l) = Average of Columns (e), (h), and (k).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Projected Estimated Equity Risk Premium S&P 500

Equation: K_e = Dividend Yield + g

Where:
K_e = Annual required rate of return on equity
Dividend Yield = Expected dividend yield
g = Growth rate

(a)	(b)	(c)
Line No.		
1	2019 S&P 500 Expected Dividend Yield	2.12%
2	2019 S&P 500 Expected Growth Rate	10.31%
3	Market Expected ROE (Row 1 + Row 2)	12.43%
4	Less Risk Free Rate	3.85%
5	**Estimated Market Risk Premium (Row 3 - Row 4)**	**8.58%**

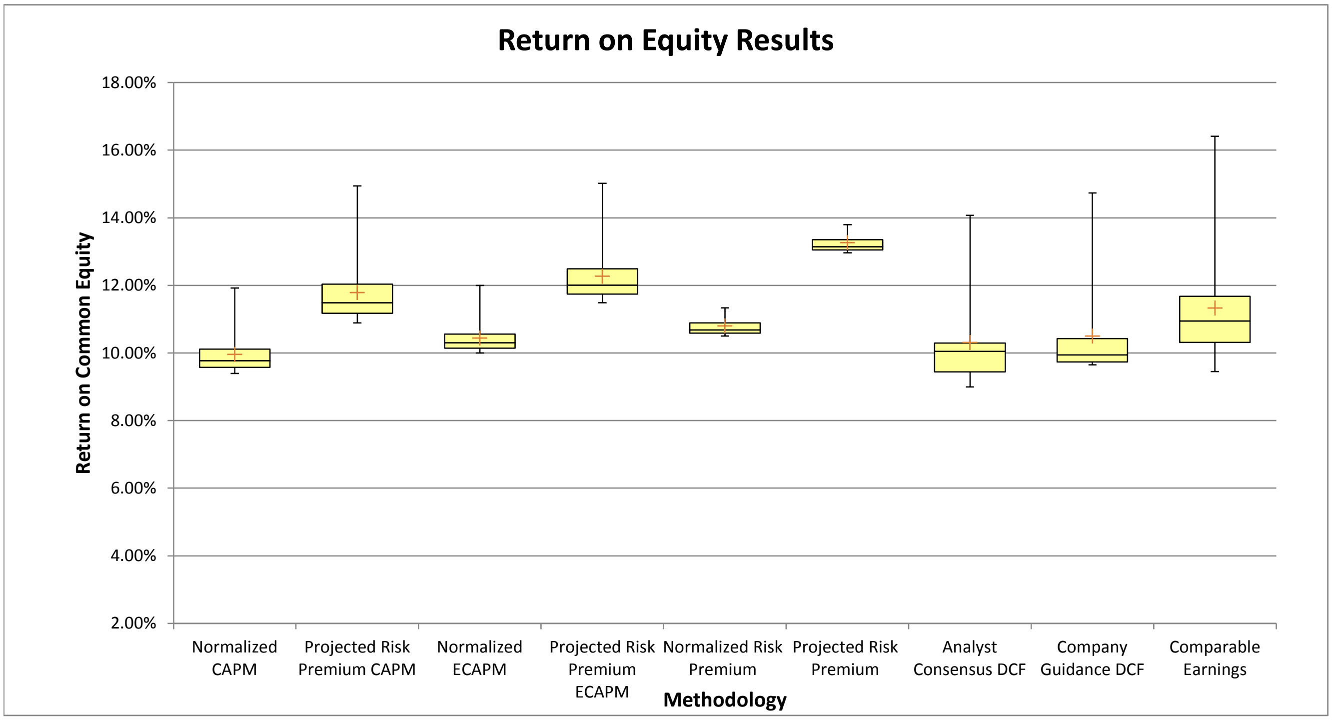
Sources:
Column (c) Rows 1 and 2: Bloomberg as of February 28, 2018.
Row 4: Exhibit A-14 (SM-1), Schedule D-5, page 2, column (f).

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Projected 12-Month Period Ending December 31, 2019

Case No.: U-20134
Exhibit No.: A-14 (SM-1)
Schedule: D-5
Page: 13 of 13
Witness: SMaddipati
Date: May 2018

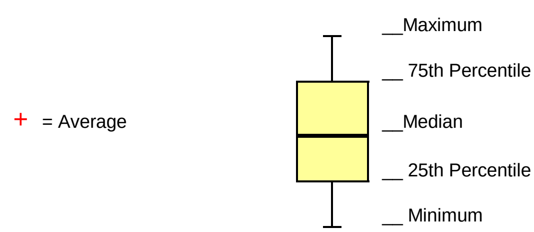
Summary of Return on Equity Results



Numerical Summary of ROE Results

		Min	25th%	Median	75th%	Max	Avg			
1	Normalized CAPM	9.40%	9.58%	9.77%	10.11%	11.92%	9.96%	Exhibit A-14 (SM-1)	Schedule D-5	Page 2 of 13
2	Projected Risk Premium CAPM	10.89%	11.18%	11.48%	12.04%	14.95%	11.78%	Exhibit A-14 (SM-1)	Schedule D-5	Page 2 of 13
3	Normalized ECAPM	10.00%	10.14%	10.30%	10.56%	11.99%	10.44%	Exhibit A-14 (SM-1)	Schedule D-5	Page 3 of 13
4	Projected Risk Premium ECAPM	11.49%	11.74%	12.01%	12.49%	15.02%	12.27%	Exhibit A-14 (SM-1)	Schedule D-5	Page 3 of 13
5	Normalized Risk Premium	10.50%	10.59%	10.68%	10.89%	11.33%	10.80%	Exhibit A-14 (SM-1)	Schedule D-5	Page 4 of 13
6	Projected Risk Premium	12.97%	13.05%	13.14%	13.35%	13.79%	13.26%	Exhibit A-14 (SM-1)	Schedule D-5	Page 4 of 13
7	Analyst Consensus DCF	8.99%	9.44%	10.04%	10.30%	14.07%	10.31%	Exhibit A-14 (SM-1)	Schedule D-5	Page 5 of 13
8	Company Guidance DCF	9.64%	9.73%	9.94%	10.43%	14.74%	10.50%	Exhibit A-14 (SM-1)	Schedule D-5	Page 5 of 13
9	Comparable Earnings	9.45%	10.31%	10.95%	11.68%	16.41%	11.33%	Exhibit A-14 (SM-1)	Schedule D-5	Page 6 of 13

10 Recommended Cost of Equity Range for Consumers Energy: 10.0% - 11.0%



UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Belmont Municipal Light Department; Braintree Electric Light Department; Concord Municipal Light Plant; Georgetown Municipal Light Department; Groveland Electric Light Department; Hingham Municipal Lighting Plant; Littleton Electric Light & Water Department; Middleborough Gas & Electric Department; Middleton Electric Light Department; Reading Municipal Light Department; Rowley Municipal Lighting Plant; Taunton Municipal Lighting Plant; Wellesley Municipal Light Plant, Complainants, v. Central Maine Power Company; Emera Maine (formerly known as Bangor Hydro-Electric Company); Eversource Energy Service Company and its operating company affiliates: The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and NSTAR Electric Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; The United Illuminating Company; Fitchburg Gas and Electric Light Company; and Vermont Transco, LLC, Respondents.	)	Docket No. EL16-64-002

ANSWERING TESTIMONY AND EXHIBITS OF

JOHN D. QUACKENBUSH, CFA

**ON BEHALF OF
THE NEW ENGLAND TRANSMISSION OWNERS**

MARCH 23, 2017

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EXHIBITS TO ANSWERING TESTIMONY

Exhibit No.	**Description**
NET-02301	Qualifications of John D. Quackenbush
NET-02302	Federal Funds Effective Rate
NET-02303	Yields on U.S. Treasury Securities
NET-02304	Yields on Ten-Year U.S. Treasury Securities
NET-02305	Moody's Baa Utility Bond Yields
NET-02306	Yields on Global Government Securities
NET-02307	Securities Held Outright by the Federal Reserve Bank
NET-02308	RRA State-Authorized ROEs

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is John D. Quackenbush and my business address is 46320 Station Road, New Buffalo, Michigan 49117. I am the President of JQ Resources, LLC.

Q2. HAVE YOU PREVIOUSLY APPEARED AS A WITNESS IN ANY CASES BEFORE THIS COMMISSION?

A2. No, but I have testified as a witness before state regulatory commissions including the Florida Public Service Commission, the Kansas Corporation Commission, the Illinois Commerce Commission, the Missouri Public Service Commission, the Nevada Public Service Commission, the New Jersey Board of Public Utilities, the North Carolina Utilities Commission, the Oregon Public Utility Commission, the South Carolina Public Service Commission, the Tennessee Public Service Commission, and the Public Utility Commission of Texas. Additionally, I have served as the Chairman of the Michigan Public Service Commission and the Chief Financial Analyst of the Illinois Commerce Commission.

A listing of my qualifications is presented as Exhibit No. NET-02301.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A3. I am appearing on behalf of the Respondents in this proceeding, a group of New England Transmission Owners (NETOs), to respond to the direct testimony of Dr. Lesser and Dr. Peters filed on behalf of Eastern Massachusetts Consumer-Owned Systems (EMCOS). In particular, my testimony will rebut the erroneous assertions of Dr. Lesser that the existence of DCF model risk is incompatible with the Commission's finding that the Efficient Market Hypothesis is valid. I will demonstrate that the anomalous capital market conditions that prevailed in the time period relevant to this proceeding have not changed from those that the Commission found to be anomalous in Opinion No. 531 and Opinion No. 551.[1] I will also rebut Dr. Peter's assertion that the New England region is in danger of building too much transmission infrastructure and Dr. Peters' recommendation that Dr. Lesser's recommended base ROE of 8.59% should be adjusted downward by 39 basis points to 8.20% due to capital structure issues. I will also explain my view that Dr. Lesser and Dr. Peters misjudge the relative risk of transmission and distribution investments and that vertically integrated electric utility state-authorized ROEs, rather than distribution-only state-authorized ROEs, are the most relevant state-regulated authorized ROEs on which the Commission should focus in this proceeding. In conclusion, I explain why the base returns on equity (ROEs) recommended by Dr. Lesser and Dr. Peters would not provide an adequate return relative to the risks of building electric transmission infrastructure and do not satisfy the requirements of the U.S. Supreme Court's guidance in the *Hope*[2] and *Bluefield*[3] decisions.

[1] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *appeals docketed*, *Emera Me. v. FERC*, No. 15-1118 (D.C. Cir. Apr. 30, 2015), *Braintree Elec. Light Dep't v. FERC*, No. 15-1119 (D.C. Cir. May 1, 2015), *Mass. v. FERC*, No. 15-1121 (D.C. Cir. May 1, 2015). *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016), *reh'g pending*.
[2] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").
[3] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("*Bluefield*").

Q4. WHAT IS THE BASIS FOR YOUR TESTIMONY?

A4. My testimony is based on my 35 years of experience working in the field of utility regulation. My career includes more than four years supporting state utility regulators as a finance staff member of the Illinois Commerce Commission; 14 years performing regulatory and treasury functions in the telecommunications industry for Sprint Corporation partially during the application of utility cost of service regulation to incumbent local exchange carriers and partially during the transition from cost of service regulation to price cap regulation; 11 years in the investment community covering approximately 80 North American companies including regulated utilities, building U.S. and Canadian domestic portfolios, and leading the global utilities team in building global utility portfolios for UBS Global Asset Management (UBS); more than four years regulating utilities as a state utility regulatory commissioner at the Michigan Public Service Commission; and most recently providing consulting services for the last year to participants in regulated utility industries.

In preparing my testimony, I relied on my own knowledge of both U.S. and global financial markets and areas of investment with which the NETOs compete in the capital markets for investor funds. Also, I regularly meet and interact with institutional investors and sell-side security analysts that focus on the utility sector and I continue to monitor how investors currently perceive and evaluate utility investment opportunities and risks.

Q5. WHAT DO YOU MEAN WHEN YOU SAY YOU COVERED 80 NORTH AMERICAN COMPANIES INCLUDING REGULATED UTILITIES AT UBS?

A5. My duties at UBS during 2001 through 2011 included building a five-year forecasted income statement, balance sheet, and cash flow statement for each covered company. The exact number of covered companies varied over time with mergers, acquisitions, and divestitures, but I generally covered approximately 40 regulated electric utilities at any time. I also met regularly with the senior management, customers, suppliers, and regulators of each covered company. During my time at UBS, I directed the investment of significant amounts of client funds in several owners of NETOs, including Northeast Utilities (a predecessor of Eversource Energy and parent of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire) in the U.S. portfolio, Emera (parent of Emera Maine) in the Canadian portfolio, NextEra Energy and its predecessor FPL Group (owner of New Hampshire Transmission LLC) in the U.S. portfolio, and National Grid (parent of New England Power Company) in the global portfolio.

Q6. WHILE WORKING IN THE TELECOMMUNICATIONS INDUSTRY, WHAT TREASURY DUTIES DID YOU PERFORM THAT ARE RELEVANT TO THE ISSUES IN THIS PROCEEDING?

A6. At Sprint Corporation, during the period from 1995 through 2000, I prepared risk-adjusted cost of capital estimates on a quarterly basis that were used for capital investment, valuation, mergers and acquisitions, Economic Value Added (EVA), and product / service costing analysis across divisions. These risk-adjusted cost of capital estimates varied by division and were utilized as hurdle rates for capital budgeting decisions across the Local, Long Distance, and Wireless Divisions.

Additionally, during 1995 through 2000, I was responsible for managing Sprint's relationships with four rating agencies. In providing the quantitative and qualitative information required by the rating agencies to rate the parent and several separately-rated subsidiaries, I became familiar with how the rating agencies differentiated risk among different companies and subsidiaries of the same company.

II. SUMMARY OF CONCLUSIONS

Q7. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A7. I conclude that the anomalous capital market conditions that the Commission previously found to exist in Opinion No. 531 and Opinion No. 551 still persist. I disagree with the conclusion of Dr. Peters that there has been too much transmission investment in New England. To the contrary, transmission investment in New England occurs under the direction of ISO-NE and only after a rigorous needs and solutions assessment. I also disagree with both Dr. Lesser and Dr. Peters on the relative risk of transmission and distribution investment and concur with the Commission's previous conclusion that transmission investment is more risky than distribution investment. Furthermore, Dr. Peters' proposal to reduce Dr. Lesser's already inadequate recommended base ROE by 39 basis points is inappropriate. Finally, I demonstrate that both Dr. Lesser's and Dr. Peters' base ROE recommendations are grossly inadequate for the NETOs to meet the *Hope* and *Bluefield* standards.

III. ANOMALOUS CAPITAL MARKET CONDITIONS PERSIST

Q8. IN OPINION NO. 531 AND OPINION NO. 551, DID THE COMMISSION REACH ANY FINDINGS THAT ARE RELEVANT TO YOUR TESTIMONY IN THIS PROCEEDING?

A8. Yes. These two opinions contain a number of findings that are relevant to my testimony. With respect to capital market conditions, the Commission stated in Paragraph 142 of Opinion No. 531:

> [W]e conclude that a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*. Therefore, based on the record in this case, including the unusual capital market conditions present, we conclude that the just and reasonable base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness.

The Commission continued in paragraph 145 of Opinion No. 531:

> We are concerned that capital market conditions in the record are anomalous, thereby making it difficult to determine the return necessary for public utilities to attract capital. In these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards. We find it necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.

Turning to Opinion No. 551, the Commission found in paragraph 122:

> Because the evidence in this proceeding indicates that capital market conditions continue to reflect the type of unusual conditions that the Commission identified in Opinion No.

> 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with *Hope* and *Bluefield*.

Furthermore, the Commission concluded in paragraph 137 of Opinion No. 551:

> [D]ue to the presence of unusual capital market conditions, we find it appropriate to look to other record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness produced by the DCF methodology.

Q9. BASED ON YOUR STATE REGULATORY EXPERIENCE, IS WHAT THE COMMISSION DID BY CONSIDERING MULTIPLE ROE METHODOLOGIES AND SETTING THE BASE ROE ABOVE THE MIDPOINT OF A ZONE AT ALL UNUSUAL?

A9. No, it is not. In making ROE decisions, it is typical for regulatory commissions to be confronted with a record consisting of multiple methodologies from multiple witnesses. Amid the plethora of evidence before it, the regulatory commission is charged with considering and weighing all the evidence and determining a specific authorized base ROE. The "weighing" part is challenging and can be different in each commissioner's reasoning, but the task at hand for commissioners is to agree on an authorized base ROE that is within the zone defined by the evidence. There are circumstances that may lead a commission to conclude that the midpoint of the zone is appropriate, but at other times, the weight of the evidence dictates that there is reason to select a different point in the zone. It is not surprising that under certain circumstances, commissions may choose to emphasize a particular methodology while downplaying that same methodology in different circumstances. Similarly, it is not surprising that under certain circumstances, a commission may find that it is appropriate to give more weight to the upper part or even the very top of the zone. Given this perpetual challenge that faces regulatory commissions in general, it is not surprising that the Commission decided to rely on multiple methods and set the base ROE above the midpoint of a zone of reasonableness.

Q10. IN ANOMALOUS MARKET CONDITIONS, SHOULD THE COMMISSION BE CONCERNED ABOUT MODEL RISK?

A10. Yes, it should. Model risk is the risk that a model used to evaluate real-world situations will fail to predict or represent the real phenomenon that is being modeled. For example, the DCF model is often used to estimate the cost of equity. The implementation of the DCF model requires inputs including the dividend yield and the expected growth rate. If a financial analyst implements the DCF model but relies on unusual or anomalous dividend yields or growth rates, the model outputs are unlikely to represent an accurate estimate of the cost of equity.

An ROE recommendation by a witness or an ROE decision by a regulator requires both the application of financial models and the use of informed judgment. An ROE based solely on judgment would be inappropriate, as would be an ROE that relied solely on the mechanical application of theoretical financial models. In my opinion, it is common for regulatory commissions to acknowledge that any theoretical model, no matter how conceptually appealing and well-supported, needs to be supplemented with informed judgment. Commissions are on a constant quest to balance the theoretical with the practical.

Q11. HOW DO INVESTORS VIEW MODEL RISK?

A11. Investors use many valuation approaches, and the traditional DCF methodology is among the most important. However, investors do not have homogeneous expectations. Not all investors use the same tools or inputs. Differing expectations are what result in different investors placing different valuations on the same investment, thus creating a marketplace. I will focus my comments on large institutional investors that are the primary price-determining force in the marketplace, as these large institutional investors tend to engage in more complex, independent analysis than retail investors do. I want to point out, though, that even sophisticated investors do not have homogeneous expectations.

While at UBS, our primary valuation approach incorporated DCF and CAPM methodologies. To enhance investment comparisons across industries, all analysts covering different industries used a specific type of multi-stage DCF model, but I know of other large institutional investors that used different and simpler single-stage or two-stage DCF models. At UBS, analysts initially developed individual cash flow projections for each company generally for the next five years and industry "normal" growth, which by default began in year ten. Years six through ten were modeled as a transition from the company-specific growth rate toward the industry growth rate in year ten. The analysts had discretion to deviate from the default five year initial period and year ten start of the "normal" period in the DCF model if justified by specific circumstances. At UBS, our DCF inputs of expected dividends and expected growth rates were driven largely by the financial modeling we did to forecast income statements, balance sheets, and cash flow statements. I know that my DCF growth rate estimates differed from other investors and often did not match consensus. I also know analysts and investors that give more weight to non-DCF valuation tools. But regardless of model differences and different inputs to the model, investors apply judgment to the results in making investment decisions. Thoughtful investors do not rely exclusively on mechanical application of a single theoretical model. As with regulators, investors are constantly balancing theory and the real world.

Q12. DR. LESSER CRITICIZES COMMISSION FINDINGS ON MODEL RISK FOUND IN OPINION NO. 531 AND OPINION NO. 551. PLEASE COMMENT.

A12. Dr. Lesser quotes from Footnote 286 of Opinion No. 531, which states:

> As the NETOs' witness Lapson testified, "There is 'model risk' associated with excessive reliance or mechanical application of a model when the surrounding conditions are outside the normal range. 'Model risk' is the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled."

Dr. Lesser also quotes from Finding 125 of Opinion No. 551, which states:

> Consistent with Opinion No. 531, we find that the DCF methodology is subject to model risk of providing unreliable outputs in the presence of unusual capital market conditions.

Dr. Lesser takes issue with the Commission's finding that model risk exists. Dr. Lesser attempts to prepare a theoretical critique of model risk and concludes model risk theoretically cannot exist. However, Dr. Lesser completely misses the point that the Commission does not need more theory, but rather, it is concerned, as are investors, with balancing the theoretical and the practical.

Q13. WHAT ARE YOUR VIEWS ON DR. LESSER'S DISCUSSION OF THE EFFICIENT MARKET HYPOTHESIS?

A13. Dr. Lesser postulates a false argument when he asserts that the efficient market hypothesis is repudiated by the FERC's past findings of the existence of model risk and anomalous capital markets conditions. Mechanical application of any model can entail model risk depending on the inputs and the model's ability to reflect reality. Dr. Lesser assumes that theoretical models do not have practical limitations and thus his comments on model risk are ill-informed, as judgment must always be applied to assess how well the mechanical application of a theoretical model reflects the real world.

Model risk exists in the real world, is a practical consideration for both investors and commissions, and does not attack or invalidate the efficient market hypothesis. Mechanically plugging data into a model, no matter how theoretically robust, can result in outputs that do not reflect the real world. Model risk and the lack of a perfect cost of capital model is further evidenced by the continual quest of academics and practitioners to discover new models.

Furthermore, Dr. Lesser's extensive exercise related to the lambda factor fundamentally misses the point that a theoretical model, by definition, is never a true reflection of all the parameters that investors consider when making investment decisions. Any model abstracts from reality and makes simplifying assumptions to get to a practicable result.

Dr. Lesser essentially treats a simplified model as the ultimate truth. Dr. Lesser's lambda exercise ignores the crux of the issue - the Commission intuitively found that outputs of alternative models were deemed more representative of reality than the two-stage DCF model results given prevailing anomalous market conditions.

Q14. DO YOU AGREE WITH THE COMMISSION'S PREVIOUS FINDING ON THE EFFICIENT MARKET HYPOTHESIS?

A14. Yes. The Commission found in paragraph 132 of Opinion No. 551 that:

> The finding that mechanical application of the DCF methodology may produce results inconsistent with *Hope* and *Bluefield* in certain circumstances is not inconsistent with the efficient market theory underlying the typical application of the DCF methodology in normal circumstances.

I agree with the Commission that a finding of anomalous capital market conditions is not inconsistent with the Efficient Market Hypothesis, and I disagree with Dr. Lesser's assertion on this point.

Q15. WHAT LEADS YOU TO CONCLUDE THAT THE ANOMALOUS CAPITAL MARKET CONDITIONS RECOGNIZED BY THE COMMISSION IN OPINION NO. 531 AND OPINION NO. 551 ARE STILL IN EFFECT?

A15. In response to the global financial crisis of 2008, the U.S. Federal Reserve Bank and other global central banks began a massive monetary stimulus program in late 2008 / early 2009 that created and have perpetuated anomalous capital market conditions. According to the Federal Reserve Bank of New York Staff Report No. 441 entitled "Large Scale Asset Purchases by the Federal Reserve: Did They Work?" dated March 2010, the Federal Reserve Bank's traditional policy instrument, the target federal funds rate, had effectively been driven to its lower bound of zero. In order to further ease the stance of monetary policy as the economic outlook deteriorated, the Federal Reserve Bank purchased massive quantities of assets with medium and long maturities. These purchased securities are reported on the Federal Reserve Bank balance sheet as "Securities Held Outright." These purchases led to significant and long-lasting reductions in longer-term interest rates on a range of securities, including securities that were not included in the purchase programs. Many other countries faced the same policy dilemma, making the impact global.

Janet Yellen, Chair of the Board of Governors of the Federal Reserve System, confirmed in a speech on March 3, 2017:

> [O]nce the Committee had cut the federal funds rate to near zero in late 2008, it became necessary to deploy new tools to supply the considerable monetary accommodation required by the extremely weak state of the job market and persistently low inflation. Those tools—especially our large-scale securities purchases and increasingly forward guidance pertaining to the likely future path of the federal funds rate—enabled the Federal Reserve to provide necessary additional support to the U.S. economy by pushing down longer-term interest rates and easing financial conditions more generally.[4]

Chair Yellen continued by mentioning that the Federal Reserve Bank completed its latest round of large-scale asset purchases, sometimes referred to as quantitative easing, or QE, in 2014. The Federal Open Market Committee (FOMC) then issued a set of "normalization principles" that indicated its intention "to maintain the overall size of the Federal

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[4] Janet L. Yellen, Chair, Bd. of Governors of Fed. Reserve Sys., From Adding Accommodation to Scaling It Back (Mar. 3, 2017), https://www.federalreserve.gov/newsevents/speech/yellen20170303a.htm.

Reserve's balance sheet at an elevated level until sometime after the FOMC had begun to raise its target for the federal funds rate." Chair Yellen's March 3, 2017 speech contained footnote 9 that explained:

> Large Federal Reserve holdings of longer-term securities reduce the total amount of such securities available for purchase by the public, exerting upward pressure on their prices and, thus, depressing their yields and contributing to lower borrowing costs for American families and businesses.

U.S. and global financial markets continue demonstrably to exhibit the effects during the relevant Complaint IV period of a massive exercise of monetary policy which has produced anomalous capital market conditions. This anomaly impacts monetary aggregates, interest rates, and the valuation of financial assets due to the significant and unprecedented amount of monetary stimulus that has been applied by the U.S. Federal Reserve Bank and other global central banks including the European Central Bank, the Bank of Japan, the Bank of England, the Swiss National Bank, and the Bank of Canada.

U.S. and global interest rates and financial markets remain subject to powerful and unprecedented monetary policy actions by the Federal Reserve Bank and other global central banks that continue to affect capital market conditions during the refund period of this proceeding beginning on April 29, 2016 and during the time periods utilized by Dr. Lesser and NETOs' Witness McKenzie for their DCF analyses in this proceeding. The abnormal capital market conditions include very low U.S. and global long-term and short-term interest rates and monetary supply significantly in excess of its normal use. The anomaly is evident in unusually low U.S. Treasury bond yields and utility bond yields.

Besides very low interest rates, a hugely significant component of the monetary stimulus has been quantitative easing, or the ramp up and maintenance of an unprecedented $4.2 trillion level of U.S. Treasuries and mortgage-backed securities purchased and held outright by the Federal Reserve Bank. Dr. Lesser focuses his comments solely on low interest rates and downplays the impact of the massive amount of Treasury and mortgage-backed securities held outright by the Federal Reserve Bank.

Q16. WHAT ARE THE IMPORTANT TIME PERIODS OF THIS PROCEEDING?

A16. The FERC has set a refund effective date of April 29, 2016 for this complaint. The refund period is therefore from approximately May 2016 through July 2017. In addition, Dr. Lesser has used a DCF analysis period of July 1, 2016 to December 31, 2016. NETOs' Witness McKenzie has utilized a DCF analysis period of September 2016 to February 2017. Both witnesses are using DCF study periods during the refund period. Prospective rates from this proceeding will be effective upon the Commission's decision in this proceeding, likely in mid-2018. Anomalous market conditions have existed during the refund period to date and continue. I cannot predict with certainty the market conditions that will exist in mid-2018 and beyond, but there have been no indications at this time that the Federal Reserve plans to sell the $4.2 trillion of securities it currently holds, even if there may be several more increases in the federal funds rate by mid-2018.

Q17. PLEASE DESCRIBE CURRENT U.S. INTEREST RATE LEVELS.

A17. Despite recent increases from record lows, interest rates are still extraordinarily low. I draw this conclusion after comparing short-term and long-term U.S. and global interest rates.

The federal funds rate is an important benchmark in financial markets and is the primary policy tool of the Federal Reserve Bank. The federal funds effective rate is the interest rate at which depository institutions lend to each other overnight. The Federal Open Market Committee (FOMC) establishes the federal funds target rate and then the Federal Reserve Bank uses open market operations to influence the U.S. money supply to ensure that the federal funds effective rate follows the federal funds target rate. A time series of the federal funds effective rate since 1954 is shown on Exhibit No. NET-02302. The current federal funds effective rate is low at 0.66% as of February 28, 2017. By comparison, the federal funds effective rate ranged from 4.24% to 5.26% during the pre-crisis base period of 2006 to 2007; 0.14% to 0.16% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 0.07% to 0.12% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 0.37% to 0.66% during the refund period to date of this proceeding, April 29, 2016 to February 28, 2017. When observers say that the FOMC is expected to raise interest rates three times during 2017, three times during 2018, and three times during 2019, it is the target federal funds rate to which they refer. On March 15, 2017, the FOMC decided to raise the target federal funds rate 25 basis points to a range of 0.75% to 1.00%. The Committee disclosed in a press release that "the federal funds rate is likely to remain, for some time, significantly below levels that are expected to prevail in the longer run." Changes in the federal funds rate have a direct influence on short-term market interest rates and a limited influence on long-term market interest rates.

A frequently cited short-term market interest rate is the yield on one-month U.S. Treasury securities. One-month U.S. Treasury yields are low at 0.40% as of February 28, 2017. A time series of one-month U.S. Treasury yields since July 2001 is shown on Exhibit No. NET-02303, along with ten-year U.S. Treasury yields. By comparison, one-month U.S. Treasury yields ranged from 2.42% to 5.27% during the pre-crisis base period of 2006 to 2007; 0.00% to 0.17% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 0.00% to 0.13% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 0.09% to 0.53% during the portion of the refund period to date of this proceeding from April 29, 2016 through the end of February 2017.

A frequently cited long-term market interest rate is the yield on ten-year U.S. Treasury securities. Ten-year U.S. Treasury yields are low at 2.36% as of February 28, 2017. A time series of ten-year U.S. Treasury yields since January 1962 is shown on Exhibit No. NET-02304, as well as since July 2001 on Exhibit No. NET-02303. By comparison, ten-year U.S. Treasury yields ranged from 3.83% to 5.26% during the pre-crisis base period of 2006 to 2007; 1.58% to 2.07% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 1.68% to 3.04% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 1.37% to 2.60% during the refund period to date of this proceeding, April 29, 2016 to February 28, 2017.

Moody's Baa-rated utility bond yields are low at 4.58% as of February 2017. A time series of Moody's Baa-rated utility bond yields since January 1968 is shown on Exhibit No. NET-02305. By comparison, Moody's Baa-rated utility bond yields ranged from 6.04% to 6.61% during the pre-crisis base period of 2006 to 2007; 4.51% to 4.74% during the Opinion No. 531 study period of October 1, 2012 to March 31, 2013; 4.39% to 5.25% during the Opinion No. 551 study period of November 12, 2013 to February 11, 2015; and 4.16% to 5.28% during the refund period to date of this proceeding, April 29, 2016 to February 28, 2017.

Q18. PLEASE DESCRIBE GLOBAL INTEREST RATE LEVELS AND HOW THEY RELATE TO U.S. INTEREST RATES.

A18. Many countries have short-term and long-term interest rates significantly lower than the U.S., due to intervention by global central banks that have, in many ways, paralleled that of the U.S. Federal Reserve Bank. A time series of global interest rates for five key countries is shown on Exhibit No. NET-02306. As of February 2017, the short-term yield on government securities was 0.88% in Canada, negative 0.33% in Germany, 0.34% in the United Kingdom, 0.06% in Japan, and negative 0.73% in Switzerland. The yields all fell precipitously in 2008 except for Japan, which experienced anomalous capital market conditions earlier than the other countries, as shown on page 1 of Exhibit No. NET-02306. Short-term central bank interest rates hovering near zero include 0.00% at the Bank of Japan and 0.00% at the European Central Bank. Negative interest rates are unsustainable and indicate that investors are paying for the privilege of holding government debt. In the U.S., as can be seen from Exhibit NET-02303, the one-month U.S. Treasury yield scraped down to 0.00% for several days at several times between December 2008 and October 2015, but never fell negative.

Likewise, as of February 2017, the ten-year yield on government securities was 1.71% in Canada, 0.26% in Germany, 1.31% in the United Kingdom, 0.08% in Japan, and negative 0.21% in Switzerland, as shown on page 2 of Exhibit No. NET-02306. The negative ten-year government yield in Switzerland is especially notable. Negative interest rates on ten-year government securities are even more anomalous and unsustainable than negative interest rates on short-term government securities.

Global interest rates even lower that U.S. interest rates motivate foreign investors to invest in U.S. securities. The capital marketplace is globally competitive. These extraordinarily low global interest rates help explain why global investors are attracted to U.S. debt and dividend-paying equities and further show the persistence of anomalous capital market conditions in the U.S. and globally.

Q19. PLEASE SUMMARIZE THE INTEREST RATES THAT YOU HAVE DISCUSSED.

A19. The following table summarizes some relevant interest rate comparisons. For comparison purposes, I began with a pre-crisis base period of 2006 to 2007. I also show the interest rate that prevailed during the Opinion No. 531 and Opinion No. 551 study periods. Finally, I show interest rates that have existed during the relevant refund period of this proceeding to date along with the most recent rates available at the time I prepared my testimony.

INTEREST RATE TABLE

(% per annum)

Interest Rates	Pre-Crisis 2006 to 2007	531 Study Period 10-1-12 to 3-31-13	551 Study Period 11-12-13 to 2-11-15	Refund Period To Date 4-29-16 to 2-28-17	Recent 2/28/2017
U.S. Interest Rates					
Federal Funds Effective Rate	4.24 to 5.26	0.14 to 0.16	0.07 to 0.12	0.37 to 0.66	0.66
One-Month US Treasury Yield	2.42 to 5.27	0.00 to 0.17	0.00 to 0.13	0.09 to 0.53	0.40
Ten-Year US Treasury Yield	3.83 to 5.26	1.58 to 2.07	1.68 to 3.04	1.37 to 2.60	2.36
Moody's Baa Utility Yield	6.04 to 6.61	4.51 to 4.74	4.39 to 5.25	4.16 to 5.28	4.58
Global Short-Term Governments Yields					
Germany	2.51 to 4.85	0.19 to 0.22	0.05 to 0.33	-0.33 to -0.25	-0.33
Japan	0.10 to 0.87	0.25 to 0.33	0.17 to 0.22	0.06 to 0.06	0.06
Canada	3.62 to 5.12	1.16 to 1.16	0.89 to 1.19	0.81 to 0.88	0.88
United Kingdom	4.52 to 6.58	0.49 to 0.54	0.50 to 0.55	0.34 to 0.57	0.34
Switzerland	1.02 to 2.90	0.01 to 0.03	-0.85 to 0.02	-0.78 to -0.73	-0.73
Global Ten-Year Governments Yields					
Germany	3.32 to 4.56	1.30 to 1.54	0.30 to 1.80	-0.15 to 0.26	0.26
Japan	1.50 to 1.96	0.49 to 0.78	0.28 to 0.69	-0.24 to 0.08	0.08
Canada	3.98 to 4.61	1.74 to 1.97	1.38 to 2.67	1.04 to 1.73	1.71
United Kingdom	4.08 to 5.43	1.77 to 2.18	1.59 to 2.95	0.74 to 1.57	1.31
Switzerland	2.15 to 3.19	0.53 to 0.79	-0.07 to 1.25	-0.54 to -0.07	-0.21

This table demonstrates that U.S. and global interest rates to date continue to be extremely, unusually, and anomalously low. Refund period interest rates are similar to or lower than interest rates during the Opinion No. 531 and Opinion No. 551 study periods and are significantly lower than interest rates observed during the pre-crisis base period of 2006 to 2007.

Q20. PLEASE DESCRIBE THE OTHER SIGNIFICANT COMPONENT OF THE U.S. FEDERAL RESERVE BANK'S EXTREME MONETARY POLICY: THE SECURITIES PURCHASED AND

HELD OFF OF THE OPEN MARKET BY THE FEDERAL RESERVE BANK.

A20. The balance of Federal Reserve Bank securities held outright is still massive at $4.2 trillion. A time series of securities held outright since 2002 is shown on Exhibit No. NET-02307. The massive Federal Reserve Bank purchases of securities during 2009 to 2014 is often referred to as quantitative easing (QE) and consists primarily of longer-term U.S. Treasury and mortgage-backed securities. The massive balance of securities held outright is a huge overhang on the Federal Reserve Bank balance sheet. The $4.2 trillion balance has been maintained since 2014 by the reinvestment of interest and principal payments. The March 15, 2017 Federal Reserve press release stated: "The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency and mortgage-backed securities and of rolling over maturing Treasury securities at auction, and it anticipates doing so until normalization of the level of the federal funds rate is well under way. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions."

This policy of maintaining massive amounts of securities held outright on the Federal Reserve Bank balance sheet indicates that anomalous capital market conditions will persist even after several increases in the federal funds target rate.

Q21. DO YOU HAVE ANY INDICATION OF HOW LOW U.S. INTEREST RATES MIGHT HAVE GONE IF THE FEDERAL RESERVE BANK

DID NOT PURCHASE THE MASSIVE AMOUNTS OF SECURITIES HELD OUTRIGHT?

A21. On February 9, 2017, Dr. Charles Evans, President of the Federal Reserve Bank of Chicago and member of the Federal Open Market Committee made a presentation to the CFA Society of Chicago entitled "Risk Management in a Low Interest Rate Environment." During the presentation, Dr. Evans indicated that the U.S. Federal Reserve Bank desired to avoid negative interest rates in the U.S. like those that were being experienced due to central bank monetary intervention in other global markets. The Federal Reserve Bank's massive purchases of long-term securities were an attempt to continue flooding the economy with liquidity instead of permitting interest rates to go negative, while more directly influencing long-term interest rates. Dr. Evans also indicated that, in his view, the level of negative interest rates needed to provide the Federal Reserve Bank's desired level of economic stimulus was negative 4.0%. In other words, the Federal Reserve's desired monetary stimulus was equivalent to negative interest rates at the level of negative 4.0%, but the Federal Reserve Bank found negative interest rates unpalatable to the U.S. economy. Instead, the Federal Reserve Bank achieved its desired level of economic stimulus by maintaining slightly positive interest rates and pursuing the unprecedented massive security purchases that grew the Federal Reserve Bank's securities balance from $0.5 trillion in 2008 to the $4.2 trillion it is today. This is evidence of the extraordinary lengths gone to by the Federal Reserve and why anomalous capital market conditions resulted. This is also evidence that anomalous market conditions are unlikely to disappear immediately just because short-term interest rates such as the federal funds rate and the one-month Treasury yield, are observed to be increasing. It will also be necessary to see evidence that the massive balance sheet overhang is eliminated. On February 9, 2017, Dr. Evans also mentioned that equilibrium interest rates are likely to be lower than they have been in the past. He cites a recent study that indicates that the effective real federal funds rate today is 325 basis points lower than the average in the 1970s, 1980s, and 1990s. He continues by observing that current forecasts of the equilibrium federal funds rate, including those of the FOMC, would imply a 250 basis point increase to get to equilibrium.

Q22. WHEN THE TIME COMES, HOW WILL THE FEDERAL RESERVE BANK LIKELY BEGIN REDUCING THE $4.2 TRILLION BALANCE OF SECURITIES HELD OUTRIGHT?

A22. The Federal Reserve Bank currently maintains the high balance of securities holdings by reinvesting interest payments and maturities into the purchase of new long-term securities. The Fed will likely begin to gradually reduce the $4.2 trillion balance by stopping the reinvestment of interest payments and maturities into new securities. When this reinvestment ceases, the massive balance sheet overhang will begin a gradual reduction.

Q23. HAS THE FEDERAL RESERVE BANK YET BEGUN TO CEASE THE REINVESTMENT OF INTEREST PAYMENTS AND MATURITIES?

A23. No.

Q24. WHEN MIGHT THE REINVESTMENT CEASE?

A24. On February 9, 2017, Dr. Evans indicated that, in his opinion, the Federal Reserve Bank may hike the federal funds rate three times per year for the next three years, and that the Federal Reserve Bank would be unlikely to entertain the notion of ceasing reinvestment until at least two or three more interest rate hikes occur.

Q25. WHAT OTHER EVIDENCE OF ANOMALOUS CAPITAL MARKET CONDITIONS EXIST?

A25. Dr. Lesser's Exhibit No. EMC-7 provides ample evidence that anomalous capital market conditions persist. Exhibit No. EMC-7 is a Client Alert from Duff & Phelps entitled "Duff & Phelps Increases U.S. Equity Risk Premium Recommendation to 5.5%, Effective January 31, 2016." I am not making a market risk premium recommendation in this proceeding and, as such, I do not endorse the Duff & Phelps market risk premium recommendation, but its client alert is instructive in acknowledging the prevalence of anomalous capital market conditions. This Duff & Phelps client alert recommends that a normalized risk-free rate of 4.0% be used in a CAPM analysis rather than a spot risk-free rate of 2.4%. The difference of 160 basis points is Duff & Phelps' estimated impact of anomalous capital market conditions. Duff & Phelps provides an extensive explanation of anomalous capital market conditions on page 9 through 33 of Exhibit No. EMC-7. The key point is summarized on page 31 of the Client Alert:

> As stated earlier, in most circumstances we would prefer to use the "spot" yield on U.S. government bonds available in the market as a proxy for the U.S. risk-free rate. However, during times of flight to quality and/or high levels of central bank intervention, those lower observed yields imply a lower cost of capital (all other factors held the same) – just the opposite of what one would expect in times of relative

> economic distress – so a "normalization" adjustment may be considered appropriate. By "normalization" we mean estimating a rate that more likely reflects the sustainable average return of long-term risk-free rates. *If spot yield-to-maturity were used at these times, without any other adjustments, one would arrive at an overall discount rate that is likely inappropriately low vis-à-vis the risks currently facing investors*.

Duff & Phelps concludes that mechanistic ROE calculations determined in the manner that Dr. Lesser advocates are likely to be inappropriately low vis-à-vis the risk currently facing investors. Duff & Phelps' recommended normalization is remarkably conceptually similar to this Commission's findings of anomalous capital market conditions and the decision to deviate from the DCF midpoint in Opinion No. 531 and Opinion No. 551.

Q26. PLEASE SUMMARIZE YOUR VIEW OF ANOMALOUS CAPITAL MARKET CONDITIONS.

A26. The Commission found that the conditions I describe above produced anomalous capital market conditions in Opinion No. 531 and Opinion No. 551. For all the reasons discussed above, the Commission's conclusions in those Opinions have applied since the beginning of the refund period in this Complaint IV and still apply today.

Q27. WHEN DO YOU ANTICIPATE THAT ANOMALOUS CAPITAL MARKET CONDITIONS CAUSED BY EXTREME MONETARY POLICY WILL BE OVER?

A27. I expect that there will come a day when the anomalous market conditions caused by extreme monetary policy will unwind and the extreme monetary policy will no longer have the distorting impact on capital market pricing that it does today. In my opinion, the evidence of this happening will consist of all of the following: (1) short-term interest rates rise significantly to a more normal level; (2) long-term interest rates rise significantly to a more normal level; (3) the Federal Reserve Bank discontinues rolling over interest payments on and maturities of its securities held outright; and (4) the Federal Reserve Bank sells on the open market most, if not all, of its $4.2 trillion securities held outright. None of these four events has happened yet, and there is no evidence that they will happen in the near future.

Q28. WHEN THE ANOMALOUS CONDITIONS CURRENTLY PRESENT IN THE CAPITAL MARKETS ARE RESOLVED, DO YOU BELIEVE IT WOULD BE APPROPRIATE FOR THE COMMISSION TO RELY SOLELY ON THE RESULTS OF A SINGLE DCF METHOD TO EVALUATE A FAIR ROE?

A28. No. As I noted earlier, no single methodological approach can be considered a wholly reliable indicator of investors' required return. In my experience, it is common practice for regulators to consider the results of alternative methods, along with their assessment of the merits of each approach, in arriving at a just and reasonable ROE that meets the requirements of regulatory standards.

IV. THE NETOS' EXPANSION OF THE NEW ENGLAND TRANSMISSION GRID IS CONSISTENT WITH PUBLIC POLICY AND SUBJECT TO THOROUGH REVIEW

Q29. DO YOU AGREE WITH DR. PETERS' CONCERN THAT THE NEW ENGLAND REGION IS IN DANGER OF BUILDING TOO MUCH TRANSMISSION?

A29. No, not at all. Transmission projects in New England are a result of a rigorous ISO New England (ISO-NE) planning process designed to ensure that system upgrades necessary to meet appropriate reliability standards are constructed. These reliability standards include those of North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The ISO-NE-led planning process may be thought of in two distinct phases with the first being the "needs" phase and the second being the "solutions" phase. The initial needs assessment evaluates the transmission system's performance against mandatory national and regional standards (NERC and NPCC) and if performance deficiencies are found, then a solution study is initiated. The solution study includes development and evaluation of a comprehensive list of mitigating alternatives, of which one ultimately is recommended as "preferred" to ISO-NE stakeholders.

It is important to note that throughout the entire process, New England stakeholders are given multiple opportunities to provide input and feedback both to the transmission owner and to ISO-NE staff. In addition, at any time throughout the needs or solutions phase, ISO-NE can, and has, declared the need to re-assess the study needs or solutions as a result of material forecasted system changes; for example, generation additions and retirements, and load forecast updates. This continual re-assessment of needs and solutions throughout the study process ensures that only justified transmission upgrades are constructed. Since May 2015, ISO-NE's Open Access Transmission Tariff provides for competitive solicitations to determine solutions. Nevertheless, the ISO-NE process remains rigorous and focused on adherence to mandatory national and regional standards.

While serving as Chairman of the Michigan Public Service Commission, I was familiar with the MISO and PJM transmission planning processes, as different Michigan regions participate in MISO or PJM. I observe that the ISO-NE transmission planning process shares many positive attributes of the rigorous MISO and PJM planning processes.

Most industry observers, including regulators and investors, are rightly concerned about the implications of too little energy infrastructure, including electric transmission in New England. As New England pursues additional renewable and low carbon energy sources, sufficient new transmission infrastructure must be built to allow access to those new resources.

Q30. HAVE CONGRESS AND THIS COMMISSION ENCOURAGED THE DEVELOPMENT OF TRANSMISSION?

A30. Yes, they have. Congress passed the Energy Policy Act of 2005 that set forth several statutory requirements intended to support transmission investment. The Commission, through a 2012 Policy Statement, reaffirmed its pricing reform encouraging transmission investment through incentive rate treatments to assist in mitigating the risks associated with developing, constructing, operating, and maintaining transmission infrastructure. The Commission also enabled regional and interregional coordination processes and supporting cost recovery processes through Order 1000.

Dr. Peters offers no compelling reason for Congress and the Commission to abandon their support for enhancement and expansion of transmission infrastructure. Transmission remains the smallest percentage of electricity costs when compared to distribution and generation costs. Only 11% of the average U.S. price of electricity results from the costs of transmission services.[5] Recently, the American Society of Civil Engineers (ASCE) released its 2017 Infrastructure Report Card. Using the simple "A to F" school report card format, the ACSE assigns a "D+" to energy infrastructure. Specific to transmission infrastructure, ASCE states:

> Much of the U.S. energy system predates the turn of the 20th century. Most electric transmission and distribution lines were constructed in the 1950s and 1960s with a 50-year life expectancy, and the more than 640,000 miles of high-voltage transmission lines in the lower 48 states' power grids are at full capacity. Energy infrastructure is undergoing increased investment to ensure long-term capacity and sustainability; in 2015, 40% of additional power generation came from natural gas and renewable systems. Without greater attention to aging equipment, capacity bottlenecks, and increased demand, as well as increasing storm and climate impacts, Americans will likely experience longer and more frequent power interruptions.[6]

Specific to New England, the New England States Committee on Electricity (NESCOE) recently studied the impact of the clean energy policy goals of the New England states on transmission needs. The NESCOE-sponsored report concluded that, if new transmission build is limited only to reliability-related upgrades that are currently in progress, "the region is forecast to be under-supplied with Renewable Energy

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[5] *Annual Energy Outlook 2017*, U.S. Energy Information Administration, January 2017, Table 8.

[6] *2017 Infrastructure Report Card, Energy Overview*, American Society of Civil Engineers, http://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf.

Certificates (REC) relative to Renewable Portfolio Standard (RPS) targets" by 10.5% in 2025 and by 17.0% in 2030.[7] It is clear that more transmission is needed to achieve the New England states' RPS and other clean energy requirements.

V. SHORTCOMINGS OF DR. LESSER'S AND DR. PETERS' ANALYSIS

A. Dr. Lesser and Dr. Peters Misjudge the NETOs' Risks, Particularly in Comparison to Distribution Investment

Q31. DO YOU AGREE WITH DR. PETERS' CONCLUSION THAT TRANSMISSION INVESTMENT IS LESS RISKY THAN DISTRIBUTION INVESTMENT?

A31. No, Dr. Peter's views are contrary to investors' views and directly challenge the findings of the Commission in Opinion No. 531 and Opinion No. 551.

On page 16 of Exhibit EMC-12, Dr. Peters lists 13 sources of risk and makes the blanket conclusion that the magnitude of each risk does not differ between transmission and distribution. However, at least four of his enumerated risks differ markedly between transmission and distribution, including permitting risk, cost overrun risk, schedule delays, and local opposition to construction. Transmission projects are larger and have a longer lead time to construction than distribution projects. Permitting requirements for transmission projects are more significant and provide more opportunities for local opposition to construction than distribution projects. The larger size and longer lead time of transmission projects contribute to higher risk of cost overruns and schedule delays.

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[7] *Renewable and Clean Energy Scenarios and Mechanisms 2.0 Study Base Case Results*, New England States Committee on Electricity, November 17, 2016.

Q32. DR. PETERS OPINES THAT THERE IS A "GUARANTEE" THAT THE NETOS WILL EARN THEIR AUTHORIZED ROE. DO YOU AGREE?

A32. No, I do not. There is no guarantee that the NETOs will earn their authorized ROE on transmission investment. Under the Commission's abandoned plant precedent, there is a risk that the NETOs may spend considerable sums developing projects that are never placed in service, yet not fully recover their costs. This Commission's Order 1000 contemplates that the NETOs could propose transmission projects in competitive solicitations and if not selected, the NETOs would not recover the associated development costs.

Q33. DR. LESSER APPEARS TO CONCLUDE THAT DISTRIBUTION INVESTMENTS ARE MORE RISKY THAN TRANSMISSION INVESTMENTS BECAUSE THE INTRODUCTION OF DISTRIBUTED ENERGY RESOURCES MAKES THE DISTRIBUTION GRID OBSOLETE AND THUS MORE RISKY. DO YOU AGREE?

A33. No, I do not. The distribution grid is ripe with investment opportunities due to the growth of distributed energy resources. As a result, the distribution grid needs to become even more robust and vibrant with investments in smart meters and sensors to enable the growth of distributed energy resources. Distributed energy resource owners are reliant on the distribution grid for the two-way flow of electricity. Also, the distribution grid relies upon the transmission grid for its own reliability and to ensure a reliable supply of energy. The growth of distributed energy resources does not place the distribution grid or the transmission grid in danger of becoming irrelevant.

Q34. WHAT HAS THE COMMISSION PREVIOUSLY CONCLUDED ABOUT THE RELATIVE RISK OF TRANSMISSION AND DISTRIBUTION INVESTMENT?

A34. The Commission, in Opinion No. 531, properly recognized that transmission investment is riskier than distribution investment. In fact, the Commission found in paragraph 149 of Opinion No. 531 that state-regulated electric distribution has lower business risks than electric transmission investment.

Some of the risks that the Commission noted for electric transmission are:

> For example, investors providing capital for electric transmission infrastructure face risk including the following: long delays in transmission siting, greater project complexity, environmental impact proceedings, requiring approval from multiple jurisdictions overseeing permits and rights of way, liquidity risk from financing projects that are large relative to the size of the balance sheet, and shorter investment history. We find that these factors increase the NETOs' risk relative to the state-regulated distribution companies.

Several of these transmission risks identified by the Commission have clear parallels to electric generation risks but not distribution risks, including the potential for long delays, greater project complexity, the burdensome impact of environmental regulations, multiple jurisdictions overseeing siting, environmental compliance decisions, and financing projects that are large relative to the size of the corporate balance sheet.

Nothing has changed to reverse the Commission's previous conclusion that transmission investment is riskier than distribution investment.

Q35. HOW DO INVESTORS PERCEIVE THE THREAT OF PANCAKED ROE COMPLAINTS TO IMPACT THE RELATIVE RISK OF TRANSMISSION?

A35. Investors perceive that the prospect of never-ending pancaked ROE complaints heightens both the risk of transmission investment and transmission's relative risk to distribution. For example, Value Line provides an example of the filing of an ROE complaint that caused an immediate 6% stock price drop for a transmission provider.[8] NETOs' Witness McKenzie cites a Wolfe Research report that observes that "pancaking of ROE challenges against the same transmission owners" represented one of the "real risks" to investors in transmission.[9] Moreover, a recent research note from UBS, in discussing the Commission's Final Order in the first MISO ROE complaint (EL14-12-002), stated "it's notable a third subsequent pancaked case has not been filed, a positive in our view."[10] It is clear that pancaked ROE complaints increase the risk associated with transmission investment.

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[8] The Value Line Investment Survey, ITC Holdings Corp., December 20, 2013.
[9] Wolfe Research, *Don't you FERCedabout ROE, Don't Don't Don't Don't!*, Utilities & Power (Apr. 6, 2015).
[10] *FERC Affirms the MISO Win*, UBS Global Research, September 29, 2016, at 1.

B. Capital Structure Differences Should Not Be Used to Reduce the Understated Base ROE Recommendation of Dr. Lesser

Q36. DO YOU AGREE WITH DR. PETERS' PROPOSAL TO REDUCE THE BASE ROE BY 39 BASIS POINTS TO ACCOUNT FOR CAPITAL STRUCTURE DIFFERENCES BETWEEN THE NETOS AND THE PROXY GROUP?

A36. No, I do not. To begin with, Dr. Peters' vague academic references about optimal capital structure do not offer any empirical evidence to pinpoint one. In the real world of practical corporate finance, academic theoretical references are interesting and may provide a helpful guide but do not provide a useful tool to fine tune a company's capital structure. Dr. Peters ignores real-world practical corporate financial realities.

A utility must be permitted latitude in managing capital structure ratios. Since there is no practical methodology to pinpoint theoretically optimal capital structure ratios, targeted ratios can only be broadly conceptualized. Appropriate ratios may shift over time as capital market conditions or business risk characteristics change. Additionally, the timing of upcoming issuances and maturities may influence the capital structure ratios because both the size and frequency of issuances are affected by the relative cost-effectiveness of various issuance increments. Treasury professionals need an adequate degree of flexibility to perform their duties. Given these practical considerations, capital structure ratios cannot be deemed to be inappropriate unless the ratios significantly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs. As Dr. Peters shows on his Figure 4 entitled "Least Cost Capital Structure" on page 22 of Exhibit No. EMC-12, the

Weighted Average Cost of Capital curve is shaped like a very shallow dish such that large variances in capital structure ratios lead to minimal change in overall costs.

Moreover, the Commission's proxy group selection criteria are meant to determine companies of comparable risk. The Commission has chosen to exclude capital structure as an explicit factor when determining the comparable risk proxy group. The Commission does include credit ratings in its criteria, and the credit rating agencies evaluate capital structure among other risk factors when determining credit ratings. As a result, the impact of capital structure is already included in the Commission's proxy group selection criteria. Dr. Peter's proposed adjustment would be redundant and is clearly inappropriate.

In Opinion No. 551, the Commission affirmed that it has never encouraged utilities to feature more debt in their capital structure and found that it would be inappropriate to encourage additional debt leveraging of utilities, many of which are undertaking large investments or do not have high credit ratings. The Commission points out in paragraph 286:

> [Complainants] seek a risk adjustment based upon a single factor, an alleged equity-rich capital structure, without consideration of any other risk factor. This is contrary to Commission policy.

Further, the Commission realized the redundant nature of this capital structure adjustment in paragraph 288:

> In any event, Complainants' position fails to take into account the fact that our criteria for selecting members of the proxy group are intended to produce a proxy group make up of companies of similar risk. Those criteria include screens to ensure that the proxy group contains only utilities with similar credit ratings to the utility at issue. . . . Consequently,

> additional reductions to the ROEs that are proposed by Complainants essentially reduce the ROE twice for featuring equity-rich capital structures.

Finally, the Commission concluded in paragraph 289:

> Furthermore, as a policy matter, the Commission does not directly incentivize utilities to adjust their preferred capital structures. The Commission has not previously directly encouraged utilities to feature more debt in their capital structure. We find that it would be inappropriate to encourage additional debt leveraging of utilities, many of which are undertaking large investments or do not have high credit ratings.

Dr. Peters' recommendation that the Commission depart from its well-conceived policy stance on capital structure is ill-advised and should be rejected.

C. Dr. Lesser's and Dr. Peters' Base ROE Recommendations Are Inadequate

Q37. WILL THE BASE ROES RECOMMENDED BY DRS. LESSER AND PETERS PROVIDE INVESTORS WITH A RETURN COMMENSURATE WITH THE ASSOCIATED RISK AND ATTRACT NEW CAPITAL TO TRANSMISSION INVESTMENT?

A37. No, the base ROEs of 8.59% recommended by Dr. Lesser and 8.20% recommended by Dr. Peters are way too low to attract investors to provide capital for electric transmission investments. Coming so soon after Opinion No. 531 in which the Commission established a base ROE of 10.57% and potential decisions in the second and third complaints, investors would react with surprise and alarm if the Commission determined a base ROE in this proceeding consistent with either Dr. Lesser's or Dr. Peters' recommendations. Measured against the Opinion

No. 531 authorized base ROE of 10.57%, their proposed decreases are in the range of 198 to 237 basis points and are even larger than the 175 basis point differential between the then-current authorized base ROE and the midpoint of the mechanically-applied DCF methodology that troubled the Commission in paragraph 150 of Opinion No. 531. An ROE consistent with either Dr. Lesser's or Dr. Peters' recommendations would discourage investment in transmission projects, and would have a chilling effect on all FERC-jurisdictional transmission providers, discouraging new capital investments in transmission assets.

Q38. HOW WOULD THE BASE ROES PROPOSED BY DRS. LESSER AND PETERS IMPACT THE NETOS' ABILITY TO COMPETE FOR CAPITAL IN THE GLOBAL INVESTMENT MARKETS?

A38. U.S. electric transmission investments compete in the financial market with other sectors and other geographies, including utilities and non-utility businesses. The most directly comparable sector is the state-regulated electric utility investments, and more specifically, the state-regulated vertically integrated electric utilities. The recommended base ROEs of Dr. Lesser and Dr. Peters are significantly below the lowest of the base ROE determinations over the last two years for vertically integrated electric utilities in state jurisdictions. Such a low base ROE determination would put transmission infrastructure at a competitive disadvantage in the capital market in comparison to investments in vertically integrated electric utilities.

Q39. DID YOU PERFORM AN ANALYSIS OF STATE JURISDICTIONAL BASE ROE DETERMINATIONS FOR ELECTRIC UTILITIES?

A39. Yes, I performed an analysis using jurisdictional allowed ROEs published by S&P Global Market Intelligence's Regulatory Research Associates (RRA). RRA is a respected source that is relied on for accurate jurisdictional authorized ROE information by both investors and expert witnesses in utility regulatory matters. RRA characterizes vertically integrated electric utilities as those that provide distribution, transmission, and regulated generation services.

Q40. TO YOUR KNOWLEDGE, DOES FERC RELY ON THE RESULTS OF STATE ROE DETERMINATIONS AS A BASIS FOR ITS OWN ROE DETERMINATIONS?

A40. The Commission has repeatedly affirmed the use of the DCF methodology as its primary model for determining the base ROE and the range or zone of reasonable ROEs. In Opinion No. 531, the Commission stated that the substantial difference between state ROE determinations and the midpoint of the modeled DCF range calls into question the sole reliance on the DCF midpoint without adjustment during a period of anomalous capital market conditions. The Commission stated in paragraph 148:

> Although we are not using state commission approved ROEs to establish the NETOs' ROE in this proceeding, the discrepancy between state ROEs and the 9.39 percent midpoint serves as an indicator that an upward adjustment to the midpoint here is necessary to satisfy *Hope* and *Bluefield*.

In other words, a significant difference between state-authorized ROEs and the results of the mechanical application of the DCF model is in itself further evidence that capital market conditions are anomalous. Furthermore, as the Commission explained in Opinion No. 531, its ROE determinations are guided by the Supreme Court's decisions in the *Hope* and *Bluefield* cases to allow returns on invested capital that are comparable to returns available to investors in businesses of similar risk. Therefore, evidence of state-authorized ROEs for companies in a related industry group is an important source of information to which the Commission should give weight when determining where the ROE should be placed within a range or zone of reasonableness. Furthermore, investors are clearly aware of the state-authorized ROEs, and transmission owners must compete for capital in the marketplace generally, as well as among divisions within a specific utility (some of which are global companies), against other types of utility investments, as well as against the entire range of investment opportunities in the capital markets. Thus, the information provided by ROEs recently authorized by a wide sample of state utility regulators is relevant to the Commission's decision in this proceeding.

Q41. HOW DID YOU PREPARE YOUR ANALYSIS OF THE STATE-AUTHORIZED ROES?

A41. To perform this analysis, I began with all cases reported by RRA in all jurisdictions. Because some cases are decided by the jurisdiction without an ROE finding, I captured only those cases in which RRA identified an ROE finding. Next, I reviewed orders to determine if any explicit incentives or penalties were identified in the applicable order. If applicable, I separated the authorized ROE into a base ROE and incentive adders or penalties. I then focused only on state-authorized base ROEs during the most recent 24 month period.

Q42. PLEASE EXPLAIN HOW YOU TREAT THE INCENTIVE ADDERS OR PENALTIES.

A42. In Exhibit No. NET-02308, I separate each authorized ROE reported by RRA into two components: the base ROE and any explicit ROE incentives or penalties. This separation allows me to focus on the base ROE for comparison purposes to the Commission base ROE. It is important to capture the base ROE information in the analysis and is conceptually similar to separating out the base ROE from electric transmission ROEs that contain incentive adders.

Q43. PLEASE DESCRIBE THE ADJUSTMENTS TO THE STATE ROE ANALYSIS ON PAGE 2 OF EXHIBIT NO. NET-02308.

A43. In several instances during the 24 month period, the Virginia Corporation Commission (VCC) issued multiple orders within a short period of time containing similar ROE determinations that relate to individual projects, not for the entire utility. These orders contain valuable information, but to include each and every order separately would over-represent the VCC's decisions. Therefore, as shown on page 2 of Exhibit No. NET-02308, I compress the VCC ROE determinations of individual projects that contained the same base ROE in close proximity into one observation. In other words, I replaced five ROE determinations of 10.00% for Virginia Electric and Power Company during the first half of 2015 with a single observation of 10.00%. Likewise, I replaced five ROE determinations of 9.60% for Virginia Electric and Power during the first quarter of 2016 with a single observation of 9.60%, as well as replacing two ROE determinations of 9.60% during the second quarter of 2016 with a single observation of 9.60%. Besides the Virginia orders, I identified one ROE determination for Indianapolis Power & Light that required adjustment as shown on page 2 of Exhibit No. NET-02308. With these adjustments, the number of observations is slightly reduced and the range is unchanged, but the results are more representative.

Q44. ARE YOUR ADJUSTMENTS TO THE STATE ROES CONSISTENT WITH ADJUSTMENTS MADE BY THE NETOS IN DOCKET NOS. EL13-33 AND EL14-86?

A44. Yes, they are.

Q45. WHY DO YOU CHOOSE A 24-MONTH PERIOD FOR YOUR STATE-AUTHORIZED ROE ANALYSIS?

A45. In each quarter of a year, there are typically only a limited number of decisions in a small number of state jurisdictions for RRA to report. For example, RRA reported electric utility ROE decisions per quarter between 2 and 12 during 2015 and between 7 and 18 during 2016. In most quarters, only a few jurisdictions are represented. The sample group from quarter to quarter over 24 months is comprised of a greater variety of companies in a greater variety of jurisdictions. Some utilities are involved in frequent rate cases, while other utilities have multiple-year rate orders or have other means to avoid regular rate cases, and are rarely reported on the list of ROE determinations. Thus, the reported ROE determinations from quarter to quarter, or even year to year, do not represent a constant population of states or companies. Extending the data to eight quarters makes the sample more representative. In my opinion, using 24 months of data provides an appropriate balance between choosing a representative sample and ensuring the sample is meaningfully recent. A 24 month period also is consistent with the Commission's finding in paragraph 148 of Opinion No. 531.

Q46. WHY DO YOU CONSIDER THE VERTICALLY INTEGRATED ELECTRIC UTILITIES TO BE THE MOST APPROPRIATE GROUP FOR THE COMPARISON OF STATE-AUTHORIZED ROES?

A46. RRA reports ROE decisions at several different levels of aggregation, including separately for electric utilities and natural gas utilities, and further splitting the electric utility cases into vertically integrated cases and delivery only cases. Vertically integrated electric utilities are electric utilities that own transmission, distribution, and regulated generation assets. As I discuss in Section V.A. "Dr. Lesser and Dr. Peters Misjudge the NETOs' Risks, Particularly in Comparison to Distribution Investment," nothing has changed to alter the Commission's previous conclusion that transmission investment is more risky than distribution investment. The natural gas and electric delivery-only utilities are generally regarded by investors and state regulators as having lower business risk than vertically integrated electric utilities. Thus, the vertically integrated electric utilities group is the most representative sample group for this analysis because it is the group most similar in risk to the NETOs. For that reason, these are the utilities that I include in Exhibit No. NET-02308.

Q47. IS THE STATE-AUTHORIZED ROE METHODOLOGY THAT YOU APPLIED FOR VERTICALLY INTEGRATED UTILITIES THE SAME AS THAT USED BY NETO WITNESS LAPSON IN DOCKET NOS. EL11-66 AND EL13-33/EL14-86?

A47. Yes, it is.

Q48. WHAT DO THE STATE ROE CASES IN EXHIBIT NO. NET-02308 SHOW ABOUT DR. LESSER'S AND DR. PETERS' ROE PROPOSALS IN THIS CASE?

A48. The sample group of 44 state ROE cases is shown on page 1 of Exhibit No. NET-02308. Dr. Lesser's recommended ROE of 8.59% is a dramatic 64 basis points below the lowest of the 44 observations. Dr. Peters' recommended ROE of 8.20% is an astounding 103 basis points below the lowest of the 44 observations. If either of their proposals were adopted, it would send a strong signal that the Commission does not want capital invested in transmission.

Q49. DO YOU HAVE ANY COMMENTS ABOUT DR. PETERS' CONCLUSION ON STATE-AUTHORIZED ROES?

A49. On page 37 of Exhibit No. EMC-12, Dr. Peters concludes that the state-authorized ROE "most similar" to those approved by state commissions generally is 9.00%. To begin with, his conclusion about state-authorized ROEs is significantly flawed by his sole reliance on lower-risk electric distribution ROEs. But his conclusion of 9.00% is especially puzzling when considering how his own data fails to support his conclusion. Dr. Peters' Table 5 shows an average state-authorized ROE of 9.31% and his Table 6 shows a state-authorized ROE range of 9.17% to 9.90%. I am uncertain how Dr. Peters can conclude that the ROE "most similar" to this data is 9.00%.

Q50. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE VERTICALLY INTEGRATED UTILITIES' STATE-AUTHORIZED ROES.

A50. The state-authorized ROEs demonstrate that the ROE recommendations of Dr. Lesser and Dr. Peters are much too low to attract investment to transmission infrastructure. If limited to the ROE recommendations of Drs. Lesser and Peters, the NETOs would be unable to achieve returns on transmission investment that meet the *Hope* and *Bluefield* standards and would not be able to raise capital for transmission investment.

VI. SUMMARY AND CONCLUSION

Q51. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A51. I conclude that the anomalous capital market conditions that the Commission previously found to exist still persist. I disagree with the conclusion of Dr. Peters that there has been too much transmission investment in New England. To the contrary, transmission investment in New England occurs under the direction of ISO-NE and only after a rigorous needs and solutions assessment. I also disagree with both Dr. Lesser and Dr. Peters on the relative risk of transmission and distribution investment and concur with the Commission's previous conclusion that transmission investment is more risky than distribution investment. Furthermore, Dr. Peters' proposal to reduce Dr. Lesser's already inadequate recommended base ROE by 39 basis points for capital structure considerations is inappropriate. Finally, I demonstrate that both Dr. Lesser's and Dr. Peters' base ROE recommendations are grossly inadequate for the NETOs to meet the *Hope* and *Bluefield* standards.

Q52. DOES THIS CONCLUDE YOUR TESTIMONY?

A52. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Belmont Municipal Light Department, *et al.*	)	
v.	)	**Docket No. EL16-64-002**
	)	
Central Maine Power Company, *et al.*	)	

AFFIDAVIT OF JOHN D. QUACKENBUSH

John D. Quackenbush, being first duly sworn, deposes and says that he is the John D. Quackenbush referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

John Quackenbush

John D. Quackenbush

Subscribed and sworn to before me this 23RD day of March, 2017, by John D. Quackenbush, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Carol C Shubert

Notary Public

Commission Expires on:

CAROL C SHUBERT
Notary Public, State of Michigan
County of Berrien
My Commission Expires 12-23-2019
Acting in the County of Berrien

156 FERC ¶ 61,234
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Tony Clark.

Association of Businesses Advocating Tariff Equity — Docket No. EL14-12-002
Coalition of MISO Transmission Customers
Illinois Industrial Energy Consumers
Indiana Industrial Energy Consumers, Inc.
Minnesota Large Industrial Group
Wisconsin Industrial Energy Group

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

OPINION NO. 551

ORDER ON INITIAL DECISION

(Issued September 28, 2016)

Paragraph Numbers

1. This order addresses briefs on and opposing exceptions to an Initial Decision issued on December 22, 2015 by the presiding Administrative Law Judge (Presiding Judge) in the captioned proceedings.[1] The Initial Decision set forth the Presiding Judge's findings concerning a complaint filed pursuant to section 206 of the Federal Power Act (FPA)[2] challenging the Midcontinent Independent System Operator, Inc. (MISO) Transmission Owners' (TOs) base return on equity (ROE) reflected in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff). In this order, we affirm the Initial Decision.

I. **Background**

2. On September 23, 2002, the Commission affirmed an initial decision that approved a base ROE of 12.38 percent for MISO TOs, but the Commission modified the initial decision to include an upward adjustment of 50 basis points for turning over operational control of transmission facilities.[3] On remand from the U.S. Court of Appeals for the District of Columbia Circuit, among other things, the Commission vacated its prior order concerning the 50 basis point adder and stated that MISO TOs may make filings under section 205 of the FPA to include an incentive adder.[4] The 12.38 percent base ROE continues to be the applicable ROE under Attachment O of the MISO Tariff used by all MISO TOs except for American Transmission Company, LLC (ATC).[5]

[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. System Operator, Inc.*, 153 FERC ¶ 63,027 (2015) (Initial Decision).

[2] 16 U.S.C. § 824e (2012).

[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 (2002), *order denying reh'g*, 102 FERC ¶ 61,143 (2003).

[4] *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,355 (2005).

[5] ATC's base ROE of 12.2 percent was established as part of a settlement agreement that was filed with the Commission on March 26, 2004. In Docket No. ER04-108-000, the Commission approved the uncontested settlement. *Am. Transmission Co. LLC*, 107 FERC ¶ 61,117 (2004).

3. On November 12, 2013, Complainants[6] filed a complaint (Complaint) alleging that the current base ROE is unjust and unreasonable. Additionally, Complainants argued that the capital structures of certain MISO TOs feature unreasonably high amounts of common equity and that MISO TOs' capital structures should be capped at 50 percent common equity. Finally, Complainants contended that the ROE incentive adders received by ITC Transmission for being a member of a regional transmission organization (RTO) and by both ITC Transmission and Michigan Electric Transmission Company, LLC (METC) for being independent transmission owners were unjust and unreasonable and should be eliminated.

4. On October 16, 2014, the Commission set for hearing the issue of whether MISO TOs' base ROE is unjust and unreasonable and established the refund effective date at November 12, 2013.[7] The Commission denied the Complaint with respect to the capital structure issue, finding that Complainants had neither demonstrated that such existing capital structures are not just and reasonable nor cited any precedent for capping, for ratemaking purposes, the level of common equity in such capital structures for individual utilities, much less groups of utilities.[8] The Commission also denied the Complaint with respect to ROE incentive adders.

5. On July 21, 2016, the Commission generally denied requests for rehearing and clarification of the Hearing Order.[9] However, the Commission clarified that non-public utility transmission owners are subject to the outcome of this proceeding. Therefore, the Commission stated that, if the Commission find that MISO TOs' existing base ROE is unjust and unreasonable and requires them to amend their Attachment Os. Accordingly, the Commission will also require those non-public utility transmission owners that incorporate the existing base ROE in their rates to amend their Attachment Os to incorporate the just and reasonable base ROE on a prospective basis. However, the Commission stated that the MISO non-public utility transmission owners would only be

[6] Complainants, a group of large industrial customers, are: Association of Businesses Advocating Tariff Equity; Coalition of MISO Transmission Customers; Illinois Industrial Energy Consumers; Indiana Industrial Energy Consumers, Inc.; Minnesota Large Industrial Group; and Wisconsin Industrial Energy Group.

[7] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.* 149 FERC ¶ 61,049, at P 188 (2014) (Hearing Order).

[8] *Id.* P 190.

[9] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 156 FERC ¶ 61,060 (2016) (Rehearing Order).

subject to any refund obligations imposed in this proceeding to the extent they have voluntarily committed to make such refunds in prior FPA section 205 proceedings relating to the inclusion of the transmission revenue requirement in MISO's jurisdictional rates.[10]

6. On February 12, 2015, in Docket No. EL15-45-000, a different set of complainants filed a second complaint challenging the public utility MISO TOs' base ROE. By order dated June 18, 2015, the Commission set this matter for hearing and established a refund effective date of February 12, 2015, the day after the expiration of the refund period established by the Hearing Order. That refund period expired May 11, 2016.[11]

7. On December 22, 2015, in this proceeding, the Presiding Judge issued the Initial Decision finding, *inter alia*, that MISO TOs' existing 12.38 percent base ROE is unjust and unreasonable and should be reduced to 10.32 percent. The Presiding Judge also prescribed refunds, with interest, for the period from November 12, 2013 through February 11, 2015.[12] In the Initial Decision, the Presiding Judge explained that the 10.32 percent base ROE represents the midpoint of the upper half of the zone of reasonableness (upper midpoint) of 7.23 percent to 11.35 percent.[13]

[10] *Id.* PP 47-48.

[11] *Arkansas Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015) (Second Complaint Hearing Order).

[12] Initial Decision, 153 FERC ¶ 63,027 at P 491.

[13] *Id.* P 110.

8. Joint Customer Intervenors,[14] Complainants, MISO TOs,[15] Resale Power Group of Iowa (Iowa Group), and Trial Staff each filed briefs on exception and opposing exceptions to the Initial Decision. Organization of MISO States (OMS) filed a brief on exceptions and jointly filed, with Joint Consumer Advocates, a brief opposing exceptions.[16]

[14] Joint Customer Intervenors consist of Arkansas Electric Cooperative Corporation, Mississippi Delta Energy Agency and its members, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi and Public Service Commission of Yazoo City, Mississippi, Hoosier Energy Rural Electric Cooperative, Inc., South Mississippi Electric Power Association, and Southwestern Electric Cooperative.

[15] MISO TOs for the purpose of this order refers to: ALLETE, Inc. for its operating division Minnesota Power (and its subsidiary Superior Water, L&P); Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Cleco Power LLC; Duke Energy Corporation for Duke Energy Indiana, Inc.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC Transmission; ITC Midwest LLC; METC; MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wolverine Power Supply Cooperative, Inc. Intervenor Xcel Energy Services Inc. did not join certain of the MISO Transmission Owners' pleadings in this proceeding, but generally supports this brief on behalf of respondents Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation. *See* MISO TOs Brief on Exceptions at n.1.

[16] On February 10, 2016, Joint Consumer Advocates also filed a brief on exceptions, which were due on January 21, 2016. Because of its lateness, we do not consider this brief part of the record in this proceeding. *See* 18 C.F.R. § 385.711(a)(1)(i) (2016).

II. Overview of the Commission's Determinations in this Order

9. In this order, we affirm the conclusions of Initial Decision. We find the Presiding Judge correctly determined that there were anomalous capital market conditions, such that we have less confidence that the midpoint of the zone of reasonableness produced by a mechanical application of the Discounted Cash Flow (DCF) methodology satisfies the capital attraction standards of *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*[17] and *Federal Power Commission v. Hope Natural Gas Co.*[18] We affirm that, in these circumstances, the Presiding Judge reasonably considered evidence of alternative methodologies for determining ROE and the ROEs approved by state regulatory commissions, for purposes of deciding whether the MISO TOs' ROE should be set at a point above the midpoint of the DCF zone of reasonableness. That evidence corroborates our determination that an ROE above the midpoint is necessary to satisfy *Hope* and *Bluefield*. Accordingly, we find that the just and reasonable ROE for the MISO TOs should be set at the central tendency of the upper half of the zone of reasonableness. We agree with the Presiding Judge that, as a result of this analysis, the appropriate base ROE for MISO TOs is 10.32 percent. We find that the Presiding Judge correctly applied the DCF methodology, including its inclusion of TECO Energy, Inc. (TECO) in the DCF proxy group. As discussed below, we also find that MISO TOs correctly employed the expected earnings alternative, though this finding does not affect the Initial Decision's conclusion.

10. We agree with the Presiding Judge that the base ROE should not be reduced for certain MISO TOs based on their capital structure or the use of transmission formula rates. We also reject Complainants' proposed "quartile approach," as discussed below. Except where specifically mentioned herein, we affirm the determinations in the Initial Decision.

III. Discussion

A. Burden of Proof

1. Initial Decision

11. The Presiding Judge explained that, to modify a rate under FPA section 206, the Commission or complainant has the burden of showing that the existing rate is unjust and unreasonable. He also explained that a "complainant shows that a Base ROE is unjust

[17] 262 U.S. 679, 692-93 (1923) (*Bluefield*).

[18] 320 U.S. 591, 603 (1944) (*Hope*).

and unreasonable by establishing that it is higher than is necessary to meet the requirements set forth in [*Hope* and *Bluefield*]."[19] The Presiding Judge further explained that *Bluefield* dictates that the return should be "equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties."[20] Additionally, the Presiding Judge noted that the return should be "commensurate with returns on investments in other enterprises having corresponding risks."[21]

12. The Presiding Judge continued, stating that the return "should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."[22] That is, the return should be "sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital."[23]

13. Finally, the Presiding Judge stated that a base ROE that "authorized a utility to collect more than is necessary to satisfy the requirements of *Hope* and *Bluefield* would exploit consumers and, therefore, would be unjust and unreasonable," so "Complainants and other participants seeking reduction of MISO TOs' Base ROE . . . have the burden of proving that MISO TOs' Base ROE exceed that level."[24] The Presiding Judge further stated that "[i]f the evidence establishes that MISO TOs exceed [the zone of reasonableness], [Complainants] will have met their burden."[25]

2. <u>Briefs on Exceptions</u>

14. Joint Customer Intervenors argue that the Initial Decision is ambiguous and could be interpreted to mean that, in order to meet their burden, Complainants and aligned

[19] Initial Decision, 153 FERC ¶ 63,027 at P 19.

[20] *Bluefield*, 262 U.S. at 693.

[21] *Hope*, 320 U.S. at 603.

[22] *Bluefield*, 262 U.S. at 693.

[23] *Hope*, 320 U.S. at 603.

[24] Initial Decision, 153 FERC ¶ 63,027 at P 24.

[25] *Id.* P 26.

parties must establish that the ROE exceeds the zone of reasonableness.[26] Joint Customer Intervenors assert that, while such a showing would suffice to meet their burden, the ROE may also be unjust and unreasonable even if it is not outside the zone of reasonableness. Joint Customer Intervenors argues that, to find otherwise would be incorrect and inconsistent with *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Electric Company*,[27] and Joint Customer Intervenors take exception to the extent that the Initial Decision held an ROE must be outside the zone of reasonableness to be unjust and unreasonable.[28]

3. <u>Briefs Opposing Exceptions</u>

15. MISO TOs challenge Joint Customer Intervenors' claim. MISO TOs argue that the Presiding Judge did not need to "delve into the nuances of the burden of proof . . . and neither should the Commission."[29]

4. <u>Commission Determination</u>

16. We affirm that FPA section 206 does not require complainants or the Commission to demonstrate that an existing ROE falls outside the zone of reasonableness in order for that ROE to be considered unjust and unreasonable. The Commission disagreed with MISO TOs' identical argument in the Rehearing Order in this proceeding.[30] Moreover, as the Commission has previously concluded, not all points within the zone of reasonableness necessarily satisfy the just and reasonable standard.[31]

[26] Joint Customer Intervenors Brief on Exceptions at 9 (citing Initial Decision, 153 FERC ¶ 63,027 at P 26).

[27] Opinion No. 531, 147 FERC ¶ 61,234, at P 12, Opinion No. 531, Opinion No. 531-A, *order on paper hearing*, 149 FERC ¶ 61,032 (2014), Opinion No. 531-B, *order on reh'g*, 150 FERC ¶ 61,165 (2015) (citing *RITELine Ill., LLC*, 137 FERC ¶ 61,039, at P 68 (2011); *N. Pass Transmission LLC*, 134 FERC ¶ 61,095, at P 46 (2011); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at P 51 (2010)).

[28] Joint Customer Intervenors Brief on Exceptions at 9-10.

[29] MISO TOs Brief Opposing Exceptions at 49.

[30] *See* Rehearing Order, 156 FERC ¶ 61,060 at P 17.

[31] *Id*.

B. Proxy Group and DCF Analysis

17. In order to determine the just and reasonable ROE for public utilities, the Commission applies the DCF model to a proxy group of comparable companies. The Commission uses the following standards to select the proxy group: (1) a national group of companies considered electric utilities by Value Line Investment Survey (Value Line); (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.[32]

18. With simplifying assumptions, the formula for the DCF model reduces to: P = D/k-g, where "P" is the price of the common stock, "D" is the current dividend, "k" is the discount rate (or investors' required rate of return), and "g" is the expected growth rate in dividends. For ratemaking purposes, the Commission rearranges the DCF formula to solve for "k", the discount rate, which represents the rate of return that investors require to invest in a company's common stock, and then multiplies the dividend yield by the expression (1+.5g) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1+.5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the "adjusted dividend yield." The resulting formula is known as the constant growth DCF model and can be expressed as follows: k=D/P (1+.5g) + g. Under the Commission's two-step DCF methodology, the input for the expected dividend growth rate, "g," is calculated using both short-term and long-term growth projections.[33] Those two growth rate estimates are averaged, with the short-term growth rate estimate receiving two-thirds weighting and the long-term growth rate estimate receiving one-third weighting.[34] The Commission generally conducts the DCF analysis based on the most recent six months of financial data in the record.[35]

[32] Opinion No. 531, 147 FERC ¶ 61,234 at P 92.

[33] *Id.* PP 15-17, 36-40, *order on paper hearing,* Opinion No. 531-A, 149 FERC ¶ 61,032 at P 10.

[34] Opinion No. 531, 147 FERC ¶ 61,234 at PP 17, 39.

[35] *Id.* P 160.

19. In this case, the Presiding Judge determined that the DCF Study Period for calculating the zone of reasonableness should be the most recent six-month period for which there is financial data in the record, January to June 2015.[36] He rejected MISO TOs' argument that the Commission should not include data subsequent to the November 12, 2013 to February 10, 2015 refund period unless the data are "reasonably representative of the refund period."[37] While the study period utilized in Opinion No. 531 roughly coincided with the refund period, the Presiding Judge noted that that similarity is not an "essential element" of the Commission's decision to consider data outside of the refund period.[38] In any case, the Presiding Judge observed, the overlap between the study period and the refund period in Opinion No. 531 was not much greater than it is here. Lastly, the Presiding Judge noted that any ROE established as part of this proceeding is likely to apply for "an appreciable period of time outside of the Refund Period." [39] Accordingly, the best course of action is to fashion a base ROE based on the most recent data in record.

20. In order to establish a proxy group, the Presiding Judge reviewed the DCF-determined cost of equity for 42 companies. The Presiding Judge determined that 37 of those companies should be included in the proxy group. Of those companies, the lowest cost of equity was Public Service Enterprise Group's 7.23 percent and the highest cost was TECO's 11.35 percent.[40] As described in more detail below, the Presiding Judge rejected contentions that TECO should be excluded from the proxy group because of certain Merger and Acquisition (M&A) Activity. However, following Opinion No. 531, the Presiding Judge excluded three companies — Edison International, FirstEnergy Corporation (FirstEnergy), and Entergy Corporation (Entergy) — because their ROEs were less than 5.65 percent, which is 100 basis points above the average yield for public utility bonds rated Baa by Moody's.[41] The Presiding Judge also excluded Madison Gas and Electric Energy, Inc. because it did not have a credit rating from either Moody's Investors Service or S&P and, therefore, could not be shown to have a credit rating of not

[36] Initial Decision, 153 FERC ¶ 63,027 at PP 56, 61.

[37] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 64.

[38] Initial Decision, 153 FERC ¶ 63,027 at P 58.

[39] *Id.* P 61.

[40] *Id.* P 63.

[41] *Id.* PP 66-67.

more than one notch above or below MISO TOs, as required by Opinion No 531.[42] In addition, the Presiding Judge also excluded Unitil Corporation (Unitil) from the proxy group because it is not one of the companies covered by Value Line and because, unlike the companies in Value Line, Unitil has a capitalization of less than $1 billion.[43]

21. For short-term growth rates, the Presiding Judge adopted the five-year growth rates proposed by Complainants' witness, Mr. Gorman, and, for companies not included in Mr. Gorman's sample, five-year growth rates proposed by Joint Consumer Advocates' witness, Mr. Hill. Both provided projected Institutional Brokers' Estimate System (IBES) growth estimates published by *Yahoo! Finance* obtained on July 13, 2015.[44] For the long-term growth rate, the Presiding Judge adopted the 4.39 percent Gross Domestic Product (GDP) growth rate proposed by Trial Staff witness, Mr. Keyton, reasoning that his method of calculating the growth rate most closely paralleled the method that the Commission used in Opinion No. 531.[45]

22. The parties' briefs on exceptions raise two issues with respect to the Presiding Judge's rulings with respect to the proxy group and the DCF analysis of each member of the proxy group. These are: (1) whether TECO should have been excluded from the proxy group and (2) whether in future cases short-term growth projections could be based on Value Line data. We address these issues below.

1. <u>Inclusion of TECO in the Proxy Group</u>

23. As explained in Opinion No. 531, the Commission's practice is "to eliminate from the proxy group any company engaged in M&A activity significant enough to distort the [company's] DCF inputs" — i.e., the company's "stock prices, dividends, or growth rates."[46] TECO is the only company whose M&A activity is at issue here. We first summarize TECO's M&A activity before turning to the Initial Decision, the briefs on and opposing exceptions, and our decision whether to include TECO in the proxy group.

[42] *Id.* PP 70, 72 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 106).

[43] *Id.* PP 74-75, 77.

[44] *Id.* P 49.

[45] *Id.* P 44.

[46] Opinion No. 531, 147 FERC ¶ 61,234 at P 114.

24. TECO engaged in two M&A activities that could potentially require its exclusion from the proxy group. First, on September 2, 2014, nearly four months before the beginning of the updated the study period, TECO completed its acquisition of New Mexico Gas Company (New Mexico Gas).[47] The record reveals that, several months later, during the January 2015 to June 2015 study period, analysts were still assessing the impact of the New Mexico Gas acquisition on TECO earnings. For example, the May 22, 2015 issue of Value Line noted that the acquisition should increase TECO's earnings, although the acquisition was just one of several factors, including strong customer growth and impending rate increases, that Value Line identified to support the projected increase in TECO's earnings for 2015 and 2016.[48]

25. Second, on October 20, 2014, roughly a month after closing the New Mexico Gas acquisition, TECO announced an agreement to sell its coal mining subsidiary, TECO Coal Corporation (TECO Coal) to Cambrian Coal Corp. (Cambrian) for $120 million and a contingent payment of up to $50 million, depending on coal prices.[49] TECO's stock price rose approximately 8 percent in the month following news of the sale. A few months later, in February 2015, TECO announced an amendment to the terms of the agreement that lowered the purchase price to $80 million, but increased the maximum contingent payment to $60 million.[50] Later in February, a securities analyst at UBS upgraded TECO from "neutral" to "buy," noting the potential sale of TECO Coal as one of the reasons for the upgrade. Throughout this period in early 2015, IBES's growth projections for TECO increased from 6.43 percent in January to 7.08 percent in February and all the way up to 9.20 percent by March 2015, even as at least one analyst expressed skepticism that TECO would complete the sale of TECO Coal.[51]

26. In April 2015, TECO announced that it was considering selling TECO Coal to other potential buyers in the event that the deal with Cambrian fell through.[52] As it happened, TECO announced in June 2015, the last month of the study period, that the deal with Cambrian had not closed as scheduled, but that it had received a non-binding

[47] Exh. S-4 at 12.

[48] Initial Decision, 153 FERC ¶ 63,027 at P 91; Exh. S-6 at 161.

[49] *Id.* P 98; Exh. S-3.

[50] *Id.* P 98. The terms of the sale were amended again in mid-April 2015.

[51] *Id.* P 101; Exh. S-4 at 15; S-6 at 147, 171.

[52] Initial Decision, 153 FERC ¶ 63,027 at P 99.

offer for TECO Coal from an undisclosed buyer. The IBES growth projections remained steady at 9.20 percent throughout April, May, and June, notwithstanding the multiple reports casting doubt on TECO's ability to complete the sale of TECO Coal.[53] In early July 2015, TECO announced that it had failed to reach an agreement with the undisclosed buyer, but that a sale of TECO Coal to Cambrian remained a possibility. A week later, on July 13, 2015, IBES's growth projection for TECO declined to 7.68 percent.[54] The Presiding Judge used the 7.68 percent IBES growth projection in his DCF analysis of TECO.

a. **Initial Decision**

27. The Presiding Judge rejected the contentions of Complainants, Joint Customer Intervenors, Iowa Group, and Trial Staff that TECO should be excluded from the proxy group.[55] The Presiding Judge concluded that neither the acquisition of New Mexico Gas nor the attempted sale of TECO Coal was sufficient to "distort" the DCF inputs.[56] Beginning with the New Mexico Gas acquisition, the Presiding Judge concluded that any earnings distortion caused by the acquisition was insufficient to exclude TECO. As an initial matter, the Presiding Judge noted that Mr. Gorman, the "principal advocate" of excluding TECO on the basis of its acquisition of New Mexico Gas, did not advocate that position in his original testimony in February 2015, but altered his position to advocate exclusion of TECO in his updated testimony in July 2015.[57] The Presiding Judge, however, concluded that the updated information on which Mr. Gorman relied did not suggest that TECO should be excluded from the proxy group. In particular, the Presiding Judge determined that Mr. Gorman was "incorrect" to suggest that TECO's IBES growth rate had increased 280 basis points between his original and updated testimony. The Presiding Judge observed that, although it was true that the IBES growth rate estimate increased from 6.43 percent in January 2015 to 9.20 percent in June 2015, that number had declined to 7.68 percent by the time of Mr. Gorman's updated testimony, meaning

[53] *Id.* P 101; Exh.S-6 at 149, 151.

[54] Initial Decision, 153 FERC ¶ 63,027 at P 101. The Presiding Judge's Order Establishing Procedural Schedule provided that the cut-off date for data to be used by any party in updates of ROE studies would be July 13, 2015. Exh. JCA-22. *See also infra* note 88.

[55] Initial Decision, 153 FERC ¶ 63,027 at PP 79, 81.

[56] *Id.* PP 81, 96, 106.

[57] *Id.* P 82.

that the actual increase in the growth rate was just 125 basis points, less than half of the 280-basis-point increase to which Mr. Gorman testified.[58]

28. In addition, the Presiding Judge determined that Mr. Gorman's characterization of the May 2015 Value Line report was also "inaccurate."[59] The Presiding Judge noted that TECO's acquisition of New Mexico Gas was just one of many factors that led Value Line to increase its projection for TECO's 2015 earnings. As the Presiding Judge explained, Value Line also emphasized the strong growth prospects for TECO's Florida utilities and an anticipated reduction in TECO's cost of debt. The Presiding Judge also noted that Value Line's increased earnings projections for 2016 were not based on the acquisition of New Mexico Gas. Instead, the Presiding Judge concluded that that increase was based on a pending rate increase for one of TECO's Florida utilities and on New Mexico Gas's own growth projections, whose sustainability was not called into question by the evidence in the record.[60] The Presiding Judge also concluded that, because the acquisition's effect on earnings was limited to 2015, there was no reason to conclude that the acquisition would have an effect on the IBES "Next 5 Years" of growth projections, which is the basis for the DCF analysis.[61] The Presiding Judge rejected arguments that the purchase of New Mexico Gas had decreased short-term earnings expectations relative to the long-term expectations to the point of "distort[ing]" the DCF input, as the Commission to exclude a proxy company on the basis of merger activity.[62]

29. The Presiding Judge also declined to exclude TECO on the basis of its attempted sale of TECO Coal. Although concluding that the "efforts to sell TECO Coal affected investors' perceptions of TECO," the Presiding Judge nevertheless concluded that this effect did not rise to the level of a distortion.[63] The Presiding Judge noted that, throughout the study period, TECO's projected growth rate increased even as the prospects of completing the sale of TECO Coal diminished. The Presiding Judge thus concluded that the growth projections for TECO "do not appear to have been related in

[58] *Id.* P 90.

[59] *Id.* P 91.

[60] *Id.* PP 94-96.

[61] *Id.* PP 95-96.

[62] *Id.* PP 90-95.

[63] *Id.* PP 100, 106.

any way to" the efforts to sell TECO Coal.[64] In addition, the Presiding Judge recognized that, in the months after the agreement to sell TECO Coal to Cambrian, TECO's stock price increased 20 percent while the industry average decreased 2 percent.[65] Based on that divergence, the Presiding Judge concluded that the potential sale of TECO Coal "may have distorted [TECO's] dividend yield downward during the study period."[66] However, the Presiding Judge declined to exclude TECO, reasoning that, because TECO was at the upper end of the zone of reasonableness and because the divestiture efforts appeared to have lowered TECO's cost of equity, to exclude TECO would have the effect of correcting a distortion that lowered the upper bound of the zone of reasonableness by *further lowering* the upper bound of the zone.[67] That result, the Presiding Judge concluded, would make the DCF analysis a "less reliable" guide to determining TECO's cost of equity.[68] Finally, the Presiding Judge also asserted that the sale of a business unit — or, in this case, an attempted sale — is neither a merger nor an acquisition and, therefore, should not be a reason to exclude a company based on M&A activity.

b. <u>Briefs on Exception</u>

30. Complainants, Joint Customer Intervenors, and Trial Staff contend that the Presiding Judge should have excluded TECO. Joint Customer Intervenors contend that the Presiding Judge erred when he decided not to exclude TECO on the basis that it was at the top of the zone of reasonableness and that the M&A activity appeared to depress TECO's dividend yield. Joint Customer Intervenors also argue that Commission precedent requires the exclusion of any company that engages in significant M&A activity, regardless of its position in the zone of reasonableness or what effect that activity appeared to have on the DCF inputs, including the dividend yield.[69] Joint Customer Intervenors also contend that the Presiding Judge erred to the extent that he declined to exclude TECO on the basis that "[a] sale of a unit (much less an attempted

[64] *Id.* P 103.

[65] *Id.* P 104.

[66] *Id.* P 106.

[67] *Id.* P 107.

[68] *Id.* P 108.

[69] Joint Customer Intervenors Brief on Exceptions at 12; Trial Staff Brief on Exceptions at 13-14.

sale) is neither a merger nor an acquisition."[70] Joint Customer Intervenors aver that a sale is a form of M&A activity—since some company is acquiring the asset being sold—and that it "defies logic" to exclude a company that purchases an asset from the proxy group, but not exclude the company that sells it.[71] Similarly, Joint Customer Intervenors argue that the fact that the sale was not completed is irrelevant as the Commission has "routinely" excluded companies from the proxy group based on contemplated or attempted merger or acquisition activity.

31. Complainants contend that the Presiding Judge erred to the extent that he declined to exclude TECO in part because TECO's acquisition of New Mexico Gas occurred several months before the beginning of the January-June 2015 updated study period on which the Initial Decision relied.[72] Complainants defend Mr. Gorman's decision to include TECO based on the original study period, but exclude TECO based on the updated study period. They argue that, although TECO both acquired New Mexico Gas and announced the agreement to sell TECO Coal during the initial study period, which covered July-December, 2014, those activities "were perceived by investors as having only a modest impact on TECO's earnings" during that period and, therefore, Mr. Gorman reasonably decided to include TECO in the proxy group.[73] Complainants contend that during the updated study period, by contrast, there was evidence that the acquisition would have a more significant impact on TECO's earnings. In particular, Complainants point to the fact that Value Line stated that TECO's earnings were likely to increase "considerably" and listed the New Mexico Gas acquisition as one of the reasons for that prediction.[74] Complainants contend that this change in earnings expectations justified Mr. Gorman's decision to change course and exclude TECO from the proxy group. In addition, Complainants take exception to how the Presiding Judge interpreted Value Line's discussion of the factors affecting TECO's earnings. Although

[70] Joint Customer Intervenors Brief on Exceptions at 12; Trial Staff Brief on Exceptions at 14-15 (observing that a sale was sufficient to trigger a company's exclusion in Opinion No. 531).

[71] Complainants Brief on Exceptions at 14.

[72] *Id.* at 13.

[73] *Id.* at 13-14.

[74] *Id.* at 15-17. Complainants also briefly suggest that TECO should have been excluded on the basis of its attempts to sell TECO Coal. They note that TECO's stock price increased 8 percent when it announced the sale of TECO Coal. Trial Staff makes a similar point. Trial Staff Brief on Exceptions at 13.

Complainants acknowledge that there were multiple factors contributing to TECO's growth estimates, they assert that these additional factors affecting the growth do not nullify the effect of the acquisition, which they argue is sufficient to exclude TECO.[75]

32. In addition, Complainants argue that the Presiding Judge erred by concluding that Value Line's earnings forecast limited the impact of the New Mexico Gas acquisition to 2015.[76] They contend that, although Value Line discussed the acquisition's impact on 2015 earnings, it never stated that that the effects of the acquisition were limited to 2015. Complainants further contend that Value Line's discussion of the factors contributing to earnings growth in 2016 were "additional factors"—i.e., over and above those affecting the 2015 earnings—that is, they were not the only factors affecting the 2016 earnings projections. In any case, Complainants argue, the Presiding Judge wrongly concluded that the 2015 earnings projections were not included in the IBES five-year growth projections. Consequently, they contend, the Presiding Judge erred in concluding that the New Mexico Gas acquisition did not affect the IBES five-year growth projections used in the DCF analysis.[77]

33. Finally, Complainants assert that the Presiding Judge erroneously discounted Mr. Gorman's testimony on the basis that the IBES growth rate projection for TECO had increased only 125 basis points, rather than the 277 basis points that Mr. Gorman testified to. Complainants contend that Mr. Gorman's calculation was correct as of July 13, 2015, when he downloaded the information from *Yahoo! Finance* and, therefore, and that the Initial Decision was wrong to conclude that the projected growth rate had increased only 125 basis points. In any case, they argue, a 125-basis-point increase still represents a meaningful change in TECO's estimated growth rate.

34. Trial Staff echoes many of these arguments regarding TECO Coal. In particular, Trial Staff contends that the Presiding Judge failed to adequately justify the conclusion that changes in TECO's stock price, estimated growth rate, and other investment measures were not related to the sale of TECO Coal.[78]

[75] Complainants Brief on Exceptions at 20-21.

[76] *Id.* at 18.

[77] *Id.* at 19-20.

[78] Trial Staff Brief on Exceptions at 13.

c. **Briefs Opposing Exception**

35. MISO TOs contend that the Presiding Judge properly included TECO in the proxy group. They argue that the Commission's screening criteria require a company's exclusion on the basis of M&A activity only when (1) that activity takes place during the study period and (2) that activity is sufficient enough to distort the inputs for the DCF analysis.[79] Because the acquisition of New Mexico Gas took place outside the updated study period, MISO TOs assert that it does not meet the first criterion for being excluded on the basis of M&A activity. In addition, MISO TOs contend that there were several factors affecting TECO's estimated growth rate and, therefore, it is not clear whether the effects of the New Mexico Gas acquisition had a significant effect on the estimated growth rates. MISO TOs also contend that the Presiding Judge correctly concluded that the change in TECO's estimated growth rate was 125 basis points, not the 280 basis points that Mr. Gorman testified to.[80] In any case, they argue, investors did not react significantly to this information and the stock price remained within "a narrow band" during the study period.[81]

36. Turning to the sale of TECO Coal, MISO TOs contend that any distortion associated with the attempted sale would have occurred when the sale was first announced, which was before the updated study period.[82] In addition, they state that there was little variation between TECO's stock prices and those of the Dow Jones Utility Average, suggesting that whatever effect the attempted sale had on TECO's stock price was minimal.[83] MISO TOs also assert that the Presiding Judge correctly determined that the attempted sale did not significantly affect TECO's IBES growth rates or Value Line's earnings per share (EPS) estimates—a result that MISO TOs contend is not surprising given that TECO Coal accounts for less than 1.5 percent of TECO's market capitalization.[84]

[79] MISO TOs Brief Opposing Exceptions at 38.

[80] *Id.* at 41.

[81] *Id.* at 42.

[82] *Id.* at 43.

[83] *Id.* at 44-45.

[84] *Id.* at 47.

d. Commission Determination

37. We affirm the Presiding Judge's decision to include TECO in the proxy group. As explained in Opinion No. 531, it is the Commission's "practice . . . to eliminate from the proxy group any company engaged in M&A activity significant enough to *distort* the DCF inputs."[85] We do not exclude a company simply because it has engaged in any M&A activity or that activity may cause changes in the DCF inputs.[86] Rather, we exclude a company if the M&A activity may cause temporary changes in DCF inputs that are not sustainable or representative of longer-term investor expectations for the company. For the reasons that follow, we conclude that neither TECO's acquisition of New Mexico Gas nor TECO's attempted sale of TECO Coal constitutes M&A activity sufficient to distort the DCF inputs.

38. We begin with New Mexico Gas. As noted, TECO's acquisition of New Mexico Gas was completed on September 2, 2014, nearly four months before the beginning of the updated study period, which covered January-June, 2015.[87] As such, speculation about whether the acquisition would be completed could not have affected, much less distorted, the stock price or the other DCF inputs during the updated study period. Nevertheless, Complainants contend that TECO should be excluded on the grounds that the acquisition of New Mexico Gas created a temporary and unsustainable increase in TECO's expected earnings. We disagree. As an initial matter, we find that, over the course of the updated study period, the IBES growth estimates increased 125 basis points, not 280 basis points that Mr. Gorman testified to.[88] However, as illustrated by the July 13, 2015 *Yahoo!*

[85] Opinion No. 531, 147 FERC ¶ 61,234 at P 114 (emphasis added).

[86] *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129, at PP 67-68 (2006) ("We also reject [the] . . . argument that Commission precedent supports, in every instance, the exclusion from a proxy group of any utility engaged in merger activity."), *order on reh'g*, 122 FERC ¶ 61,265, *order on clarification*, 124 FERC ¶ 61,136 (2008).

[87] Initial Decision, 153 FERC ¶ 63,027 at PP 80, 84.

[88] Exh. JC-22 at 7. Complainants contend that there is a disputed issue of fact regarding the appropriate growth rate for TECO at the end of the updated study period. Complainants Brief on Exceptions at 21-22. They assert that Mr. Gorman's testimony, in which he states that TECO's growth rate increased by 280 basis points from its 6.43 percent level in January 2015, implies a growth rate of 9.20 percent as of the end of the study period, while Join Consumer Advocates' witness, Mr. Hill, stated that he used a growth rate of 7.68 percent. *Id.* We affirm the Presiding Judge's decision to rely on Mr. Hill's 7.68 percent growth rate. Mr. Hill's testimony states clearly that he relied upon the numbers from *Yahoo! Finance* on July 13, 2015, the cut-off date for ROE data

Finance data included along with the testimony of Mr. Hill, the actual growth projected earnings growth for TECO at the end of the updated study period used in the parties' DCF analysis was 7.68 percent, 125 basis points above the 6.43 percent at the beginning of the study period.

39. We conclude that there is no evidence in the record suggesting that the New Mexico Gas acquisition caused a significant and unsustainable increase in TECO's earnings expectations during the updated study period. The May 22, 2015 Value Line report suggests that the acquisition will increase earnings "over and above" the savings TECO will realize from no longer paying transaction costs associated with the acquisition. There is nothing suggesting that the additional increase is unsustainable. After all, all other things being equal, an earnings increase is what we would expect when a company increases its regulated gas and electric customers by 50 percent, as TECO did in acquiring New Mexico Gas.[89] In any case, the acquisition was just one of many factors, along with rate increases for TECO's Florida utilities and an anticipated reduction in TECO's cost of debt, that supported Value Line's increased earnings

used in the updated study period, to evaluate TECO's merger activity. *See* Exh. JCA-22; Order Establishing Procedural Schedule, Docket No. EL14-12, at 3 (Jan. 23, 2015). Mr. Gorman, by contrast, does not state when he compiled the growth rate data on which he relied in deciding to exclude TECO. Exh. JC-22 at 7. Although, later in his testimony, Mr. Gorman stated that he used data taken from *Yahoo! Finance* on July 13, 2015 to perform the DCF analysis, *id.* at 8, that analysis did not include TECO, as Mr. Gorman had already determined to exclude TECO from the proxy group. *See* Exh. JC-25; Exh. JC-22 at 7. As a result, there is nothing in Mr. Gorman's testimony that suggests that he used July 13, 2015 IBES data – and not data from earlier in the study period, when the IBES growth rate was 9.20 percent, Exh. S-4 at 15 – when deciding whether to exclude TECO from the proxy group. Accordingly, we agree with the Presiding Judge that the 7.68 percent growth rate used by Mr. Hill represents the more reliable figure and more clearly represents "the most recent record evidence of the growth rates actually expected by the investment community." Opinion No. 531, 147 FERC ¶ 61,234 at P 89.

[89] *See* Joint Customer Intervenors Brief on Exceptions at 12. To the extent that the parties suggest that TECO should be excluded because its earnings outlook improved because it is no longer incurring the transaction cost associated with the acquisition, we reject their argument. Adopting that position would require that the Commission exclude companies for a year after almost any major merger or acquisition as the savings from no longer incurring the transaction costs materialize in annual earnings. That result is not the purpose of the M&A screen.

projections.[90] The Value Line report thus is not evidence suggesting that the acquisition distorted TECO's expected growth rate based on temporary, short-term developments that are unlikely to continue.

40. Turning to TECO's attempts to sell TECO Coal, we similarly conclude that there is no evidence suggesting that those efforts "distorted" the DCF inputs. Unlike the acquisition of New Mexico Gas, the efforts to sell TECO extended into the updated study period and, therefore, it is possible that speculation related to the potential merger could have affected TECO's DCF inputs. Nevertheless, we conclude that any effect was either too small or too attenuated to rise to the level of a distortion requiring TECO's exclusion from the proxy group.

41. We find that the record does not show that the attempted sale of TECO Coal distorted TECO's expected earnings. We first note that TECO Coal represents less than 1.5 percent of TECO's total market capitalization.[91] The sale of such a relatively small asset is, as a general matter, not the type of input-distorting transaction that the M&A screen is intended to address. Additionally, many of the public utilities, especially relatively large companies that make a good comparison for TECO, are regularly engaged in potential mergers or acquisitions of small business units or subsidiaries. Excluding such companies from the proxy group on the basis of any small purchase or sale would unnecessarily shrink the group of representative companies, thereby making the proxy group, and the resulting DCF analysis, a less reliable tool for ensuring that the allowed ROE satisfies the requirements of *Hope* and *Bluefield*.

42. In this case, the evidence confirms that TECO's potential sale of its underperforming asset, TECO Coal, had little impact on its projected growth rates or stock prices. As the Presiding Judge observed, IBES's projected growth rates for TECO steadily increased throughout the first five months of the six-month study period, even as the prospects for selling TECO Coal steadily deteriorated.[92] If the potential sale of TECO Coal was a significant factor affecting TECO's DCF inputs, we would anticipate

[90] Initial Decision, 153 FERC ¶ 63,027 at P 91.

[91] Exh. MTO-23 at 99 (valuing TECO Coal using the most recent non-contingent purchase price for the attempted sale to Cambrian). Although it is of course possible that the expected earnings growth rate would have further increased during this period were it not for the eroding chances of a successful sale of TECO Coal, we conclude that there is no evidence in the record suggesting that the decreasing likelihood of a sale provided any such drag on TECO's earnings expectations.

[92] Initial Decision, 153 FERC ¶ 63,027 at P 103.

at least some decline in the expected growth rate as the prospects for a sale deteriorated between February and June, 2015. Instead, as noted, TECO's expected growth rate first increased between February and March and then held steady through June.[93] In short, the record simply does not suggest that the potential sale had much, if any, effect on the growth rate used in the DCF analysis.

43. Similarly, we conclude that there is no evidence in the record that the attempted sale of TECO Coal caused a distortion in TECO's stock price. The comparison of TECO's stock price versus the Dow Jones Utility Average submitted by Dr. Avera[94] shows that the two moved in near lockstep from November 2014 through April 2015, which significantly overlaps with the study period. In any case, Dr. Avera's graph shows that TECO outperformed the industry average by an even greater amount for much of March and April, 2015, when the chances of a successful sale appeared to be diminishing.[95] Once again, if the potential sale of TECO Coal was affecting TECO's DCF inputs in any significant way, we would not expect to see TECO's stock price performing well relative to the industry average even as the prospects for the sale declined. Although it might be argued that looking at relative performance is somewhat misleading, and that TECO's stock would have performed consistently worse relative to the industry average were it not for the potential sale, there is no evidence in the record suggesting that that is the case here and our M&A screen does not require a company's exclusion from the proxy group on so speculative a basis.[96]

[93] *Id.* P 101.

[94] Exh. MTO-23 at 99.

[95] The Presiding Judge did not rely on Dr. Avera's chart because the y-axis for TECO's stock price was smaller relative to the y-axis for the industry average, which, according to the Presiding Judge, caused Dr. Avera's chart to underrepresent the variation in TECO's stock price. That observation does not require us to change our conclusion, which rests in part on the fact that TECO's performed better relative to the industry average when the prospects for the sale dimmed, than when the sale appeared most likely to occur.

[96] Although there is evidence in the record that some analysts viewed TECO Coal as "a drag on shares" of TECO, Initial Decision, 153 FERC ¶ 63,027 at P 100, that evidence does not suggest that the increasingly dim prospect of eliminating that "drag" was sufficient to "distort" the DCF inputs, especially given the absence of any apparent correlation between the DCF inputs and the prospects for a successful sale of TECO Coal.

2. Short-term Growth Projection

a. Initial Decision

44. The Presiding Judge adopted IBES short-term growth rates published by *Yahoo! Finance* obtained on July 13, 2015 for each proxy company that was included in the proxy group of at least one participant.[97] The Presiding Judge further stated that the Commission has "long relied on IBES growth projections as evidence of the growth rates expected by the investment community" and that since the discontinuation of the IBES Monthly Data Book in 2008, it has consistently used the IBES growth rate estimates published by *Yahoo! Finance* as the source of analysts' consensus growth rates.[98]

45. Additionally, the Presiding Judge stated that he did not need to address the arguments MISO TOs made in support of use of Value Line growth rates because "one can only use one set of growth rates" and the "decision . . . based on the most recent data available actually dictates the use of IBES growth rates" because they were the only data presented for the DCF study period.[99]

b. Briefs on Exceptions

46. MISO TOs do not except to the Presiding Judge's use of IBES short-term growth projections in his DCF analysis of the companies included in the proxy group in this proceeding. However, they argue that the Commission should confirm that, in future proceedings as warranted by the surrounding facts and circumstances, the growth projections published by Value Line constitute an acceptable and comparable source of short-term earnings growth estimates that may be considered for use in the two-step DCF analysis.

47. MISO TOs state that MISO TOs' witness, Dr. Avera offered alternative two-step DCF studies using the IBES short-term growth estimates, as published by *Yahoo! Finance* and Value Line short-term estimates.[100] MISO TOs state that Dr. Avera's studies relied exclusively on data from the six-month period ending on January 31, 2015 (the Refund Period). All other DCF studies entered into evidence by opposing parties,

[97] Initial Decision, 153 FERC ¶ 63,027 at P 44.

[98] *Id.* P 46.

[99] *Id.* PP 48-49.

[100] MISO TOs Brief on Exceptions at 13.

whether developed for the Refund Period or the updated six-month period ending in June 2015, used IBES growth forecasts. Hence, the record contains no Value Line short-term growth estimates for the updated six-month period ending in June 2015, which the Presiding Judge used for his DCF analysis.[101] For this reason, MISO TOs state that the Presiding Judge found that his decision to evaluate the base ROE using the updated DCF study period "actually dictates use of IBES growth rates," given the record's absence of Value Line growth rates for the Update Period.[102]

48. MISO TOs request that the Commission unequivocally announce that the Initial Decision includes no merits determination regarding the appropriateness of using Value Line growth estimates in the two-step DCF methodology in public utility cases.[103] In the alternative, MISO TOs conditionally except to this aspect of the Initial Decision to ensure that this case is not interpreted as disqualifying comparable sources of short-term growth rates, including Value Line, in future proceedings.[104]

49. In support, MISO TOs argue that, as recently as Opinion No. 531, the Commission has stated that "there may be more than one valid source of growth rate estimates" and stated that, in applying the two-step DCF methodology, the "short-term growth estimate will be based on the five-year projections reported by IBES (or a comparable source)."[105] MISO TOs argue that a number of witnesses challenged the comparability of Value Line but that the Initial Decision did not address these arguments given that no party introduced Value Line data into the proceeding to determine the short-term growth rate for the Update Period.[106]

50. MISO TOs also argue that record evidence demonstrates the comparability of Value Line growth data as both IBES and Value Line projections are expressed on an EPS basis and neither "can be endorsed as systematically more reliable than the other."[107]

[101] *Id.* at 13.

[102] *Id.* at 14 (citing Initial Decision, 153 FERC ¶ 63,027 at P 49).

[103] *Id.* at 14.

[104] *Id.* at 14.

[105] *Id.* at 15.

[106] *Id.* at 15-16.

[107] *Id.* at 16.

Additionally, MISO TOs argue that no party disputes that Value Line's growth rate estimates: (1) have a wide financial community circulation; (2) reflect projections from reputable financial analysts that develop short-term growth rate estimates; (3) are reported to investors on a timely basis; and (4) are used by institutions and other investors. For these reasons, MISO TOs argue that Value Line's forecasts satisfy the comparability requirement articulated in Opinion No. 531.[108]

51. Furthermore, MISO TOs argue that previous applications of the DCF Formula using IBES growth estimates do not preclude the future use of Value Line growth estimates or undercut their reliability. In support of this position, MISO TOs point out that Value Line is a "trusted and reputable source for investment data" because it is a "widely-followed, independent investor service."[109] Additionally, MISO TOs argue that the record discredits any attempt to disqualify Value Line growth estimates as "not strictly forward looking."[110] They further argue that the Value Line user guide explains that Value Line's projections are "of growth for each item for the coming 3 to 5 years" and that it is not a detriment to inform investors of Value Line's starting point for measuring the rate of change.[111]

52. MISO TOs state that opposing parties' suggest that the Commission disqualified Value Line growth data for use in the two-step DCF methodology when, in prior proceedings, the Commission rejected proposals to use estimates from different sources for different proxy companies and/or to average IBES data with Value Line growth estimates.[112] MISO TOs argue that these cases do not involve the explicit issue that MISO TOs hope to clarify here. MISO TOs also dispute the claim that the Value Line's EPS estimates are attributable to a single analyst. They point out that, in Opinion No. 531-B, the Commission stated that it would not rely on "an analyst head-count" to evaluate the relative reliability of data sources.[113]

[108] *Id.* at 18 (citing Opinion No. 531 at P 102).

[109] *Id.* at 18-19.

[110] *Id.* at 19.

[111] *Id.* at 19-20.

[112] *Id.* at 21.

[113] *Id.* at 22.

53. MISO TOs also dispute opposing parties' attempts to show that Value Line's estimates are less current than IBES's, arguing instead that Value Line reports its estimates on a timely basis and updates them regularly.[114] MISO TOs also ask the Commission to make explicit that the EPS growth forecasts published by Value Line and IBES are presumed to be comparable, and that the source of short-term growth data to be used in any future application of the two-step DCF model will be determined on a case-by-case basis.[115]

c. **Briefs Opposing Exceptions**

54. Complainants, OMS/Joint Consumer Advocates, Joint Customer Intervenors, Iowa Group, and Trial Staff agree with the Presiding Judge's adopting IBES as the source of short-term growth rate data for this case. Complainants argue that the Presiding Judge's adoption of the five-year IBES growth rate presented by Mr. Gorman's analysis, as supplemented by the IBES data from Mr. Hill's DCF analysis, relies on the Commission's rationale for adopting IBES growth rate projections, as outlined in Opinion No. 531. Complainants state that the Commission has "long relied on IBES growth rate projections as evidence of the growth rates expected by the investment community."[116]

55. Complainants also disagree with MISO TOs' argument that neither IBES nor *Value Line* should be presumed more reliable than the other.[117] Complainants ask the Commission to dismiss this argument as moot because Value Line growth data was absent for the time period adopted by the Initial Decision. Similarly, Joint Customer Intervenors argue that addressing MISO TOs' exception here would have no impact on this proceeding, and would only influence what may or may not be appropriate in future scenarios with different facts and circumstances.[118]

56. In a similar vein, OMS/Joint Consumer Advocates state that what MISO TOs really seek is in the nature of a declaratory order, i.e., a Commission pronouncement

[114] *Id.* at 22-23.

[115] *Id.* at 23.

[116] Complainants Brief Opposing Exceptions at 5 (citing Initial Decision, 153 FERC ¶ 63,027 at P 46).

[117] *Id.* (citing MISO TOs Brief on Exceptions at 16-18).

[118] Joint Customer Intervenors Brief Opposing Exceptions at 17-18.

applicable to unspecified future cases.[119] OMS/Joint Consumer Advocates state that the Commission's rules provide other more suitable vehicles for parties to request such broad statements of generic policy, including Rule 207(a)(2), which authorizes the filing of petitions for "[a] declaratory order . . . to . . . remove uncertainty."[120] Iowa Group also characterizes the MISO TOs' request for clarification as a collateral attack on Opinion Nos. 531 and 531-B.[121]

57. OMS/Joint Consumer Advocates further state that MISO TOs are disingenuous in suggesting that the Presiding Judge rejected reliance on Value Line's short-term earnings growth rates only out of necessity, rather than based on a finding that the IBES growth rates were shown to be preferable on the merits. OMS/Joint Consumer Advocates contend that the latest Value Line reports for the adopted study period were in fact in the record for all relevant companies,[122] and, if it had been appropriate, the Presiding Judge would have used those reports' short term EPS growth rates as DCF inputs.[123] OMS/Joint Consumer Advocates state that the Commission should reject MISO TOs' request that the Commission declare that "the EPS growth forecasts published by Value Line and IBES, if available for all proxy companies, are presumed to be comparable."[124] OMS/Joint Consumer Advocates and Joint Customer Intervenors assert that Value Line's short-term earnings growth rates are patently not comparable to IBES growth rates, in multiple respects.[125] For example, OMS/Joint Consumer Advocates and Joint Customer Intervenors state that, unlike the IBES forecasts, the Value Line EPS forecasts "consist[] of an earnings estimate of only one analyst."[126] OMS/Joint Consumer Advocates also

[119] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 14 (citing MISO TOs Brief on Exceptions at 23).

[120] *Id.* at 14 (citing 18 C.F.R. § 385.207(a)(2) (2016)).

[121] Iowa Group Brief Opposing Exceptions at 8 (citing MISO TOs Brief on Exception at 14).

[122] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 11 (citing Exh. S-6 at 9-55).

[123] *Id.*

[124] *Id.* at 15 (citing MISO TOs Brief on Exceptions at 23).

[125] Joint Customer Intervenors Brief Opposing Exceptions at 5.

[126] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 15 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 72 n.145; Joint Customer Intervenors Brief

state that IBES short-term growth projections are based on analysts' independent evaluation of prospective growth and not inherently tied to past performance. By contrast, OMS/Joint Consumer Advocates state that Value Line forecasts start from an earnings baseline that starts more than three years in the past.[127] Trial Staff also state that the "ANNUAL RATES" section Value Line data used by MISO TOs' witness, Dr. Avera, are plainly from a past three-year period to a future three-year period.[128] OMS/Joint Consumer Advocates state that, because Value Line's EPS forecasts are derived from an historical three-year baseline, those estimates will be an especially poor predictor of future EPS growth.[129] In addition, OMS/Joint Consumer Advocates state that IBES updates its consensus forecast whenever there is a change in the forecast of one of its polled analysts, whereas Value Line publishes its estimates on a fixed schedule (once every three months).[130] OMS/Joint Consumer Advocates argue that at any given point in time, the IBES consensus forecast is more likely to reflect the most up to date information.[131]

58. Additionally, OMS/Joint Consumer Advocates state that Value Line's forecasts are not consistent with the Commission's decision in Opinion No. 531 to "change the way DCF analyses are conducted in public utility cases to use *the same methodology* as the Commission uses in natural gas and oil pipeline cases."[132] OMS/Joint Consumer Advocates state that Value Line's partially retrospective growth rate is not used in

Opposing Exceptions at 5 (citing Exh. JCI-4 at 21:10-14).

[127] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 16 (citing Exh. JCA-11 at 10-12; Exh. JCI-4 at 19-20; Exh. S-1 at 79-82).

[128] Trial Staff Brief Opposing Exceptions at 8 (citing Tr. 622:10; Exh. S-1 at 80-81).

[129] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 16.

[130] *Id.* (citing Exh. JCI-4 at 21:17 – 22:3).

[131] *See also* Joint Customer Intervenors Brief Opposing Exceptions at 5-6 (citing Exh. JCI-4 at 21:10-14; Opinion No. 531, 147 FERC ¶ 61,234 at P 88).

[132] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 17 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 32 (emphasis supplied)).

pipeline cases, where the precedents specifically reject using Value Line reports to test the reasonableness of projected growth rates.[133]

59. OMS/Joint Consumer Advocates and Trial Staff oppose MISO TOs' request for a case-by-case determination of the short-term growth rate forecast data source.[134] According to OMS/Joint Consumer Advocates and Iowa Group, MISO TOs' proposal would enable litigants to select whichever source of short-term growth rate data is most advantageous for a given study period.[135] Joint Customer Intervenors go further, arguing that MISO TOs chose the Value Line growth rates because they were the most advantageous source of short-term growth rates.[136]

60. In addition, OMS/Joint Consumer Advocates state that, if the Commission grants the relief that MISO TOs request, the Commission should put some boundaries around the data source debate in the future.[137] Specifically, OMS/Joint Consumer Advocates state that the Commission should provide guidance as to how it will apply the new rules in future cases.[138] Joint Customer Intervenors also argue that, while MISO TOs portray IBES as just one among many potential sources of growth rate estimates, it is only appropriate to use a comparable source of short-term growth estimates where IBES growth rate estimates are not available.[139] Iowa Group offers that in Opinion No. 531 the Commission applied exactly the same two-step DCF model that it has used for

[133] *Id.*

[134] *Id.* at 18 (citing Initial Decision, 153 FERC ¶ 63,027 at P 48); Trial Staff Brief Opposing Exceptions at 43-44.

[135] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 19 (citation omitted); Iowa Group Brief Opposing Exceptions at 11; *see also* Joint Customer Intervenors Brief Opposing Exceptions at 7.

[136] *Id.* at 7-8.

[137] Joint Customer Intervenors also express concern about the lack of boundaries here by pointing out that MISO TOs propose no criteria for judging whether a particular source is comparable. *Id.* at 7.

[138] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 20.

[139] Joint Customer Intervenors Brief Opposing Exceptions at 7.

twenty years to set returns on equity for gas and oil pipelines to electric transmission utilities. Iowa Group explains that in doing so, the Commission relied on oil and gas pipeline precedent that established its preference for IBES short-term growth rates.[140]

61. Trial Staff states that it is not the Initial Decision that states IBES estimates are "preferable" – it is the Commission's statements and actions over many years that indicate that preference.[141] Trial State further contends that the Commission has never for any purpose used the particular data from the "ANNUAL RATES" section of the Value Line company reports, which are the basis of Dr. Avera's earnings growth input.[142]

d. Commission Determination

62. We reject MISO TOs' request for clarification that the growth projections published by Value Line constitute an acceptable and comparable source of short-term earnings growth estimates that may be considered for use in the two-step DCF analysis. In Opinion No. 531, the Commission held that "in future public utility cases, the Commission will adopt the same two-step DCF methodology it uses in natural gas and oil pipeline cases."[143] While the Commission has refrained from mandating the exclusive use of IBES data in its natural gas and oil pipeline rate of return cases, the Commission has stated that "IBES data is the preferred data source for computing the short-term growth rate."[144] The Commission has explained that the "IBES data is a compilation of projected growth rates from various knowledgeable financial advisors within the investment community."[145] As such, the IBES short-term growth estimates generally represent consensus growth rate estimates by a number of analysts. By contrast, the Commission has rejected the use of Value Line growth estimates in gas pipeline ROE

[140] Iowa Group Brief Opposing Exceptions at 8-9.

[141] Trial Staff Brief Opposing Exceptions at 6.

[142] *Id.* at 8 citing Tr. 621:20-622:2.

[143] Opinion No. 531, 147 FERC ¶ 61,234 at P 39.

[144] *Nw. Pipeline Corp.*, 92 FERC ¶ 61,287, at 62,002 (2000). *See also Nw. Pipeline, Corp.*, 79 FERC ¶ 61,309, at 62,385 (1997) (finding that "[t]he IBES figures should be used for the short-run growth rate of reach of the proxy companies.").

[145] *See, e.g.*, *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266, at 62,058-62,059 (1999); *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 234 (2002).

cases, because they are the estimates of a single analyst and thus do not constitute such consensus estimates.[146]

63. MISO TOs suggest that, despite the Commission's refusal to use Value Line short-term growth estimates in natural gas and oil pipeline ROE cases, the Commission intended in Opinion No. 531 to permit the use of Value Line estimates in public utility ROE cases. They rely heavily on the Commission's statement in Opinion No. 531 that the "short-term growth estimate will be based on the projections reported by IBES (or comparable source)."[147] Opinion No. 531 provided a more extensive discussion of short-term growth rates after the general statement relied on by the MISO TOs. There, the Commission stated that the "growth rates used in the DCF model should be the growth rates expected by the market" and that the Commission "has long relied on IBES growth projections as evidence of the growth rates expected by the investment community."[148] The Commission also addressed a proposal by Trial Staff to use Reuters Estimates Database (RED) growth projections published by *reuters.com* for those companies in the proxy group for which the IBES growth projection only reflected the view of one analyst.[149] Trial Staff argued the RED growth projections should be used because they were consensus estimates reflecting the views of more than one analyst. The Commission, however, rejected this proposal because Trial Staff had not provided RED growth projections for all the companies in the proxy group, while IBES data for all the proxy companies was available in the record.[150] While the Commission stated that it is willing to allow the substitution of "comparable data," the Commission explained that "an alternative source of growth rate data should only be used when that source can be used for the growth projections of all of the proxy group companies" because using different sources could "produce skewed results, because those sources may take

[146] *Northwest Pipeline Corp.*, 87 FERC at 62,058-62,059; and *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 234. *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at n.145, stating that the Value Line data "for any company consists of an earnings estimate from only one analyst, rather than consensus estimates."

[147] Opinion No. 531, 147 FERC ¶ 61,234 at P 39.

[148] *Id.* PP 89-90.

[149] *Id.* P 90.

[150] *Id.*

different approaches to calculating growth rates."[151] For this reason, the Commission emphasized that it has "consistently used a single investor service such as IBES for the investment analysts' growth rate estimates."[152]

64. Thus, consistent with the discussion in Opinion No. 531, the Commission is willing to use short-term growth data published by a source comparable to IBES. However, because the Commission requires the use of analysts' consensus growth rates as the short-term growth rate input in the DCF methodology, only data sources that publish analysts' consensus growth rate estimates, such as the RED growth forecasts at issue in Opinion No. 531, can be considered comparable to IBES.[153] Value Line does not publish such consensus growth rate estimates. We believe that investors, particularly larger institutional investors such as mutual funds and pension funds, are far more likely to rely upon published consensus estimates than they are to rely on Value Line. In addition, published consensus estimates sourced from investment analysts, e.g., IBES's growth rate estimates, are updated on a rolling basis, sometimes as frequently as daily, and are therefore superior to Value Line's growth rate estimates, which are updated only on a lagging, quarterly basis.[154] We therefore decline to grant MISO TOs' request that we presume that the short-term growth forecasts published by Value Line and IBES to be comparable.

65. Accordingly, we affirm the Presiding Judge's holdings concerning the proxy group and the DCF analysis of each proxy company. We therefore affirm the Presiding Judge's finding that the zone of reasonableness for establishing MISO TOs' ROE is from 7.23 percent to 11.35 percent. We now turn to the issue of where within that range to set the MISO TOs' ROE.

[151] *Id.* (citing to *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004) (finding that a presiding judge is not precluded from finding candidates for inclusion in the proxy group for which comparable data can reasonably be substituted for the growth rate data reported by IBES or Value Line)).

[152] *Id.*

[153] *See, e.g.*, *id.* P 89.

[154] While we find that Value Line's *growth rate estimates* are not acceptable as the short-term consensus growth rate input for the two-step DCF model, we reiterate that Value Line is a valid source of general financial data and affirm that Value Line estimates and financial data (e.g., betas) are acceptable as inputs for alternative cost of equity methodologies.

C. Placement of the Base ROE within the Zone of Reasonableness

66. The Commission has typically set the base ROE in RTO/ISO cases at the midpoint of the zone of reasonableness.[155] However, in Opinion No. 531, the Commission found that, because of the presence of anomalous capital market conditions in that case, the central tendency of the zone of reasonableness produced by a mechanical application of the DCF methodology would not satisfy the requirements of *Hope*[156] and *Bluefield*.[157] Opinion No. 531 corroborated that finding by reference to several alternative methodologies for determining the cost of equity. The Commission accordingly concluded that the just and reasonable ROE in that case should be set at the midpoint of the upper half of the zone of reasonableness.

67. Below, we first consider whether the Presiding Judge correctly held that there are anomalous capital market conditions in this case that would justify setting MISO TOs' ROE above the midpoint produced by a mechanical application of the DCF analysis. Because we affirm the Presiding Judge's conclusion that there were anomalous market conditions, we proceed to consider whether the relevant alternative methodologies corroborate that the mechanical application of the DCF analysis does not result in an ROE consistent with *Hope* and *Bluefield*. Based on the record in this case, including the presence of unusual capital market conditions, we conclude that the just and reasonable base ROE for MISO TOs should be set at the midpoint of the upper half of the zone of reasonableness.[158] Based on the DCF study adopted by the Presiding Judge, we affirm the Presiding Judge's finding that the just and reasonable base ROE for MISO TOs is 10.32 percent.

[155] *See S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 91, remanded on other grounds sub nom. *S. Cal. Edison Co. v. FERC*, 717 F.3d 177 (2013).

[156] *Hope*, 320 U.S. 591.

[157] *Bluefield*, 262 U.S. at 693.

[158] We calculate the midpoint of the upper half of the zone as follows: (1) calculate the midpoint of the full zone of reasonableness; (2) define the upper half of the zone of reasonableness as the range of cost of equity estimates that are bounded, on the low end, by the midpoint of the full zone of reasonableness and, on the high end, by the highest cost of equity result among the proxy group companies; and (3) calculate the midpoint of the cost of equity results in that upper range, inclusive of the endpoints.

1. Anomalous Market Conditions

a. Initial Decision

68. The Presiding Judge determined that it is MISO TOs' burden to show that anomalous capital market conditions justify selecting an ROE above the midpoint of the zone of reasonableness.[159] The Presiding Judge explained that this showing required evidence that (1) anomalous conditions make it difficult to determine whether an ROE set at the midpoint of the zone of reasonableness reflects the risks facing MISO TOs and (2) other points of comparison, including credible alternative valuation models and the ROEs allowed by state public utility commissions support an ROE above the midpoint of the zone.

69. The Presiding Judge determined that anomalous market conditions existed during the study period and that these conditions complicated the task of assessing whether an ROE at the midpoint of the zone of reasonableness accurately reflected the risks facing MISO TOs.[160] The Presiding Judge determined that the Federal Reserve's "unprecedented" purchases of debt securities were the primary factor driving the reduction in short-term interest rates and, as a result, causing a reduction in the dividend yields of public utility stocks. The Presiding Judge concluded that these circumstances are unique and, in all likelihood, unsustainable and temporary because they depend on the Federal Reserve's actions to depress interest rates. The Presiding Judge also found that investors expected the Federal Reserve to allow interest rates to "normalize."[161]

70. The Presiding Judge concluded that these conditions—and the depressed interest rates in particular—had rendered the DCF model less reliable. The Presiding Judge explained that the DCF model assumes that, under normal conditions, an investor will evaluate a stock by considering the anticipated flow of future dividends, discounted for risk, that would accrue to owners of that stock.[162] However, the Presiding Judge concluded that, during the study period, investors were not abiding by the DCF model's assumptions. Instead, the Presiding Judge determined that the Federal Reserve's actions had reduced the returns on debt securities to a level that investors "find unacceptable,"

[159] Initial Decision, 153 FERC ¶ 63,027 at P 120.

[160] *Id.* P 219.

[161] *Id.* P 224.

[162] *Id.* P 226.

causing them to move their money into other classes of assets, including electric-utility stocks.[163]

71. The Presiding Judge concluded that these investors were basing their purchasing decisions "solely [on] the current yields of those stocks" and not on the present value of future dividends, as the DCF model assumes. The Presiding Judge further concluded that investors were making these decisions notwithstanding their belief that the expected rise in interest rates would inevitably cause these stocks to decline in value. The Presiding Judge further concluded that these "hot money," short-term investors would, therefore, liquidate their positions in these stocks once they "sense" that the Federal Reserve has begun to allow conditions to normalize, causing a significant decline in their price.[164] As a result, the Presiding Judge concluded that, during the study period, the interest of hot money investors had caused electric-utility stock prices to become inflated to a level that did "not reflect the risks that investment in these securities entails."

72. As a result of these findings, the Presiding Judge determined that the MISO TOs met their burden to show that "the evidence calls into question the reliability of the DCF analysis in this proceeding" and, by extension, whether the midpoint of the zone of reasonableness is the just and reasonable ROE for MISO TOs. Accordingly, the Presiding Judge determined that Opinion No. 531 required the consideration of alternative valuation methods and the ROEs recently authorized by state public utility commissions.[165]

b. <u>Briefs on Exceptions</u>

73. Complainants argue that the Presiding Judge erred in finding that anomalous market conditions existed during the relevant study period. Complainants state that Opinion No. 531 does not articulate a standard for identifying "anomalous market conditions" and that the record in this proceeding also lacks such a standard. Complainants note that the Presiding Judge, even absent evidence, extrapolates this to mean "unprecedented" and "unsustainable." Complainants contend that the Presiding Judge is unable to meet his own "unprecedented" standard because the actions of the Federal Reserve were known to investors prior to the study period.[166]

[163] *Id.* P 227.

[164] *Id.* PP 192, 228.

[165] *Id.* PP 229-230.

[166] Complainants Brief on Exceptions at 28-29.

74. Complainants contend that the record does not demonstrate that current market conditions impacted DCF inputs, focusing on the impact of Federal Reserve actions on investor behavior. Complainants state that the Presiding Judge implies that the Federal Reserve's actions are not reflected in financial market data, a theory which conflicts with the DCF analysis' assumption of efficient market theory.[167] Complainants argue that there is no basis to dispute that the Federal Reserve's policies are relevant information that is known to investors. Rather, current market conditions are already reflected in the DCF and have no impact on MISO TOs' capital attraction capabilities.[168]

75. Complainants contend that the Presiding Judge interprets *Hope* and *Bluefield's* capital attraction standard as applying only to long-term investors, an interpretation that is both unsubstantiated and without legal precedent.[169] Complainants also argue that the evidence in this proceeding demonstrates that such a distinction is unnecessary because the DCF model accounts for both long- and short-term investors.[170] According to Complainants, even if short-term investors do not purchase and hold, the sale price of the shares they sell remains based on the long-term cash flow expectations of that security.

76. Complainants argue that the record does not demonstrate that current market conditions negatively impacted MISO TOs' ability to attract capital. The Federal Reserve's policies, Complainants contend, have not resulted in increases to the current low capital cost environment.[171] Complainants assert that, given the indications by the Federal Reserve of gradual systematic change, no significant impact on capital markets is expected, as shown in an August 2015 *Bloomberg Businessweek* article.[172] Complainants argue that there is no immediate impetus for the Federal Reserve to modify or terminate its monetary policy such that the impact of Quantitative Easing will remain in effect for the foreseeable future.[173] Consequently, MISO TOs will continue to have access to

[167] *Id.* at 30 (citing Initial Decision, 153 FERC ¶ 63,027 at P 225).

[168] *Id.* at 31; *see also* Trial Staff Brief on Exceptions at 33 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 201-205).

[169] Complainants Brief on Exceptions at 31-32 (citing Initial Decision, 153 FERC ¶ 63,027 at P 207).

[170] *Id.* at 32-33 (citing Exh. JCA-11 at 25).

[171] *Id.* at 33 (citing Exh. JC-9 at 7).

[172] *Id.* at 33-34 (citing Exh. OMS-23 at 1).

[173] *Id.* at 34 (citing Exh. JC-9 at 34).

low-cost capital for the foreseeable future. Complainants also contend that the record, including statements by the Federal Reserve, undermines the Presiding Judge's finding that investors expect significant interest rate increases in the future.[174] Complainants also cite financial publications showing that investors expect interest rates to rise only gradually.[175]

77. Complainants contend that rather than relying on assertions about the actions of "hot money," the ROE should be based on the two-stage DCF analysis, without adjustments for anomalous market conditions. Complainants state that if capital market costs increase in the future such that MISO TOs' base ROE is insufficient, they may propose adjustments under section 205 of the FPA.

78. Trial Staff asserts that, while long-term interest rates are indeed low when compared to those prevailing in the recent past, they are not anomalously low when properly viewed in a longer historical context.[176] According to Trial Staff, Mr. Keyton noted that interest rates are subject to long-term cycles that can last for decades.[177] Trial Staff asserts that interest rates on 10-year U.S. Treasury bonds were under three percent during 1953, 1954 and 1955 and generally increased for almost 30 years, reaching a peak of 13.92 percent in 1981 and then receded to a level below three percent again in 2011, where they remain today.[178] Trial Staff further states that interest rates on *Moody's* Baa bonds reached a peak of 9.38 percent during the Great Depression in 1933 and generally fell for a period of 13 years, reaching a low of 3.03 percent in 1946.[179] Then, according to Trial Staff, similar to the pattern found with Treasury debt, interest rates on *Moody's* Baa bonds increased in a secular manner until reaching a peak of 16.60 percent in 1981, and subsequently began a long and steady decline, falling below five percent in 2012, where they have remained ever since.[180] Trial Staff argues that, when viewed in the context of a historical period that is long enough to capture the entirety of an interest rate

[174] *Id.* at 35 (citing Exh. S-15 at 10).

[175] *Id.* at 36 (citing Exh. OMS-22 at 2).

[176] Trial Staff Brief on Exceptions at 20.

[177] *Id.* at 20 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 123-141; 222).

[178] *Id.* at 20-21 (citing Exh. S-2, Schedule No. 1).

[179] *Id*. (citing Exh. S-2, Schedule No. 2).

[180] *Id.* at 21.

cycle, a view not available to the Commission in the Opinion No. 531 proceeding, the interest rates on long-term bonds during the DCF study periods in this proceeding are neither unusual nor demonstrably anomalous.

79. Trial Staff asserts that the Presiding Judge erred in relying on Paragraph 50 of Opinion No. 531-B[181] to reject Trial Staff's argument that, if MISO TOs' cost of equity increases in the future and long-term investors in utility stocks begin to perceive more favorable risk-adjusted investment alternatives, MISO TOs are free to file for a return that will allow them to retain the confidence of investors willing to commit funds to ensure their creditworthiness and long-term financial integrity. Although Paragraph 50 assumes that the DCF inputs have been distorted by economic abnormalities, Trial Staff states that, in this instance, the only DCF input at issue, current dividend yield, has fallen in line with declining interest rates as a result of market forces, consistent with an economic relationship that has been long accepted by the Commission. Trial Staff explains that the decline in interest rates, to a greater or lesser extent driven by policies of the Federal Reserve, as well as other market forces, has resulted in a decline in dividend yield and in the cost of equity capital. Trial Staff further explains that the current level of dividend yield on utility stocks simply reflects the decline in the cost of equity, rather than some amorphous and unexplained distortion in measuring it. Trial Staff concludes that, given the absence of credible evidence that either of the DCF inputs, current dividend yield or earnings growth has been distorted by purportedly anomalous capital market conditions, placement of MISO TOs' base ROE at the midpoint of the DCF zone of reasonableness automatically ensures that the capital attraction standards of *Hope* and *Bluefield* will be met.[182]

80. Trial Staff avers that while the Federal Reserve's Quantitative Easing programs undoubtedly helped the Treasury Department finance the large federal deficits following the 2008 financial crisis and necessarily had some impact on lowering yields on Treasury debt,[183] other actors in the financial community besides the Federal Reserve, both public and private, were acquiring Treasury debt at historically low yields. Trial Staff asserts that after the Federal Reserve's third round of Quantitative Easing program ended in October 2014, the market interest rate on long-term Treasury debt continued to decline.[184] Trial Staff asserts that this fact implies that the participation of private

[181] *Id.* at 40 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 204-205).

[182] *Id.* at 41.

[183] *Id.* at 25 (citing Exh. S-1 at 107:20-108:10).

[184] *Id.* (citing Exh. S-7).

investors contributed meaningfully to interest rates on Treasury debt, and that resulting rates were less the result of Federal Reserve intervention than the product of private capital market activity responding to prevailing market conditions.[185]

81. Trial Staff notes that, on several occasions in his Initial Decision, the Presiding Judge dismissed assertions concerning other structural reasons for the low interest rates during the DCF study period and appeared to adopt the MISO TOs' position that intervention by the Federal Reserve was the sole or central cause.[186] For example, Trial Staff states that the Presiding Judge rejected arguments by Trial Staff and other participants that the current level of long-term interest rates and their potential future trajectory is due in part to investors' expectations concerning future inflation.[187] Furthermore, Trial Staff contends that the Initial Decision presents a distorted analysis of the array of relevant economic forces impacting the capital markets during the DCF study period.

82. Trial Staff states that, while the Presiding Judge acknowledges present circumstances, he does not concede that low interest rates, low dividend yields, and high equity prices reflect low equity costs.[188] Trial Staff asserts that this is conceptually incorrect and contrary to the Commission's accepted position and may have led the Presiding Judge to make subsequent findings that are also inconsistent with the factual record and accepted economic logic.

83. Trial Staff asserts that the record lacks evidence that long-term investors in utility stocks, with at least a partial focus on the anticipated return offered by a potentially increasing stream of future dividend payouts, are deserting utility stocks. Trial Staff states that the Presiding Judge's speculation that the "Total Returns"[189] provided by an investment in utility stocks may currently be unsatisfactory to long-term investors whose participation is necessary to maintain their financial integrity and creditworthiness[190] is

[185] *Id.* at 25-26.

[186] *Id.* at 27 (citing, *e.g.*, Initial Decision, 153 FERC ¶ 63,027 at PP 170-180, 221-223).

[187] *Id.* at 27 (citing, *e.g.*, Initial Decision, 153 FERC ¶ 63,027 at PP 169, 189 n.249).

[188] *Id.* at 34 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 137, 215, 216).

[189] *Id.* at 37.

[190] *Id.* at 37-38 (citing Initial Decision, 153 FERC ¶ 63,027 at P 218).

contradicted by long-term investors' continued investment in those stocks. Trial Staff states that, while investment by "hot money" investors in utility stocks may have contributed to an increase in utility stock prices and reduced total returns provided by them by reducing current dividend yield, this merely reflects a decline in the overall market cost of debt and equity capital in an efficient market.

84. Trial Staff further argues that the Presiding Judge accepted MISO TOs' position that interest rates are likely to rise significantly in the future while virtually ignoring other evidence that this is unlikely to happen. Trial Staff points to the fact that Dr. Avera proffers a claim almost identical to that which he has been making since his testimony in the Opinion No. 531 proceeding,[191] that the existence of "widespread expectations in the investment community are for interest rates to rise significantly as the Federal Reserve moves to normalize its monetary policies and the economy moves toward a more normal pattern of growth."[192] Trial Staff counters that interest rates have gone down rather than up since that time, as shown in Exhibit No. S-7.[193] Finally, Trial Staff offers the example that, while the Presiding Judge gave decisional weight to predictions of increases in interest rates by sources cited by Dr. Avera, he dismissed the views of other observers on this same issue.[194] According to Trial Staff, under these circumstances, there is no basis to refer to alternative methodologies to inform placement of MISO TOs' cost of equity within the DCF zone.

85. Iowa Group states that MISO TOs failed to sustain their burden of proving that alleged anomalous market conditions had skewed the DCF inputs.[195] Iowa Group argues that the Presiding Judge erred by reinterpreting *Hope* and *Bluefield* to classify investors on the basis of their investment intent or motivation. Iowa Group asserts that Ms. Lapson did not quantify any impact that "hot money" investors might have on the price or prices of any particular proxy group, observing that the retreat of "hot money" would drive proxy group prices down and dividend yields up.[196]

[191] *Id.* at 30 (citing Exh. NET-300 at 12-14; Tr. 616:17-618:11).

[192] *Id.* at 30 (citing Exh. MTO-23 at 103:15-17).

[193] *Id.* at 30.

[194] *Id.* at 30-31 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 189, 223).

[195] Iowa Group Brief on Exceptions at 11.

[196] *Id.* at 13 (citing Initial Decision, 153 FERC ¶ 63,027 at P 210).

86. Iowa Group also asserts that the evidentiary record does not establish that a utility's financial stability and growth is irrelevant (or of far less interest) to short-term investors. It further states that *Hope* and *Bluefield* require that a utility's ROE be: (1) fair to *all* shareholders, regardless of the weight a shareholder places on the growth or yield of a particular stock; and (2) fair to consumers as well, meaning protecting them from exorbitant rates[197] or as Congress opined when it enacted the FPA, from deficient markets.[198] Iowa Group states that if the Presiding Judge's classification of shareholders is correct, the possibility of overcompensating investors rises significantly.

87. Iowa Group argues that the Presiding Judge also erred in finding that (1) short-term investors are supporting the proxy group utilities' stock prices, inflating share values and depressing dividend yields, and that this "fact" provides "no assurances that these utilities' Total Returns are sufficient to satisfy the requirements of the long-term investor,"[199] as well as (2) low interest rates set by the Federal Reserve Bank had distorted DCF calculations by driving down the yields of Baa Bonds and thereby skewing the 100-basis point screen.[200]

88. Additionally, Iowa Group states that the Presiding Judge excluded Edison International, FirstEnergy, and Entergy from the proxy group because their estimated ROEs (4.38 percent, 5.01 percent, and 5.36 percent, respectfully) either fell below the average Baa Bond yield (4.65 percent) or exceeded it by less than 100 basis-points. Iowa Group asserts that if, as the Presiding Judge found, short-term investors purchase utility shares only to obtain their dividend yield, it follows that such investors would purchase FirstEnergy shares because the higher adjusted dividend yield they would receive from such purchases (3.99 percent) would equal, or exceed, the yield they would receive from two of the 39 proxy group companies. Iowa Group further asserts that the same would be true for Entergy, which, according to Appendix A, has an adjusted dividend yield of 4.23 percent. Iowa Group offers that if the Presiding Judge is correct, then short-term

[197] *Id.* at 15 (citing *American Pub. Power Assoc. v FPC*, 522 F. 2d 142, 147 (D.C. Cir. 1975) (Bazelon, J. concurring) and *Washington Gas Light Co. v. Baker*, 188 F. 2d 11, 15 (D.C. Cir. 1950) (referencing U. S. Supreme Court cases dating back to 1890)).

[198] *Id.* at 15 (citing *Morgan Stanley Capital Group, Inc. v. Pub. Util. District No. 1*, 554 U.S. 527, 564 (2008) (Ginsburg, J. concurring)).

[199] *Id.* at 15-16 (citing Initial Decision, 153 FERC ¶ 63,027 at P 210).

[200] *Id.* at 18-19 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 155-157).

investors would be purchasing Entergy shares since that yield exceeds the yields they would earn on the shares of 29 out of the 37 final proxy group companies.[201]

89. Iowa Group argues that this evidence indicates that either the Presiding Judge is correct in finding all estimated ROEs below 5.65 percent (to use Dr. Avera's word) illogical and FirstEnergy and Entergy must be excluded from the final proxy group *or* it is correct in finding that short-term investors are purchasing equity only for dividend yield and FirstEnergy and Entergy should be included in the final proxy group. Iowa Group states that these findings are mutually exclusive.

90. Iowa Group states that the Presiding Judge erred when it found that low interest rates set by the Federal Reserve distorted DCF calculations by driving down the yields of Baa Bonds and thereby skewing the 100-basis point screen.[202] Iowa Group argues that the 257 basis point fluctuation in average Baa bond yields over the six and a half years after 2008 that the Presiding Judge highlighted in the Initial Decision does not prove that the DCF's low-end outlier screen was distorted.[203] In fact, Iowa Group points out that the magnitude of this fluctuation pales in comparison to other six-year periods shown on the same exhibit.[204] Iowa Group avers that the fact that a small variance in Baa bond yields coincided with Federal Reserve Bank's implementation of an economic stabilization and stimulus policy is hardly the foundation for finding a distortion in DCF calculations. Moreover, Iowa Group states that even if the "low-end outlier" screen were increased to its 2008 level of 8.22 percent and applied to the DCF results shown in the Initial Decision's Appendix B, the resulting Base ROE would be lower than that set by the Initial Decision. Iowa Group also states that this screen produces a zone of reasonableness that extends from an estimated return of 8.32 percent for SCANA Corporation to the 11.35 percent estimated return for TECO. Iowa Group asserts that, having corrected the effect of the alleged anomalous market conditions on the DCF inputs by raising the bottom of the zone, MISO TOs' new base ROE would not exceed the midpoint, which is 9.835 percent.[205]

[201] *Id.* at 17.

[202] *Id.* at 18-19 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 155-157).

[203] *Id.* at 19 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 157).

[204] *Id.* (citing Exh. S-5 at 2).

[205] *Id.* at 19-20.

91. Iowa Group asserts that the Commission has adjusted a base ROE up or down from the midpoint when there is substantial evidence to do so.[206] Iowa Group states that, given the lack of evidence to adjust a base ROE here, three options are available: (1) acknowledge the absence of evidence and set the base ROE at the midpoint; (2) re-open the record to allow the parties to submit proof as the extent of the effect; or, (3) consider Opinion No. 531's placement of the base ROE to be a default placement unless the record supports another quantification method. Iowa Group states that the Presiding Judge chose the last option, which constitutes clear error.[207] Iowa Group asserts that under the Administrative Procedure Act, the Presiding Judge was required to "articulate a rational connection between the facts found and the choices made."[208] Iowa Group further asserts that the Presiding Judge's punting of the quantification issue by defaulting to Opinion No. 531's Base ROE placement does not establish such a connection.

92. Iowa Group asserts that the Presiding Judge's utilization of a default quantification is particularly inappropriate in this case because it assumes, without proof, that the alleged anomalous market conditions affected the DCF inputs for each of the proxy companies to exactly the same extent. Iowa states that the Commission's practice of setting RTO-wide Base ROEs at the DCF midpoint rests on the assumption (upheld by the courts) that when setting the Base ROE for a diverse set of transmission companies, the midpoint of the proxy group's DCF zone of reasonableness is reasonably representative of the range of risks experienced by the RTO members. Iowa further explains that in other words, the midpoint, by taking into account the highest and lowest results, assures that the Base ROE accurately reflects the risk experienced by companies analogous to the RTO members.[209] Iowa Group states that there is no such assurance in

[206] *Id.* at 20-21 (citing *S. Cal. Edison Co.*, 92 FERC ¶ 61,070, at 61,266 (2000); *Consumers Energy Co.*, 85 FERC ¶ 61,100, at 61,363-61,364 (1998). Iowa Group explains that both of these cases involved adjusting the utility's ROE above the DCF midpoint because, based upon the record evidence, the Commission found that the utility's risk profile differed from that of the proxy group. In the case at hand, MISO TOs did not present any evidence to support a finding that they were riskier than the ID's proxy group. Iowa Group Brief on Exceptions at n.60.

[207] *Id.* at 21.

[208] *Id.* at 22 (citing *Pub. Serv. Comm'n v. Fed. Energy Reg. Comm'n*, 397 F.3d 1004, 1008 (D.C. Cir. 2005)).

[209] *Id.* (citing *S. Cal. Edison v. Fed. Energy Reg. Comm'n*, 717 F.3d 177, 183 (D.C. Cir. 2013); *City of Charlottesville v. Fed. Energy Reg. Comm'n*, 661 F.2d 945,

this case. In fact, Iowa Group avers that there is no evidence in this case as to whether the Presiding Judge's 103 basis point upward adjustment is reasonably representative of the effect of the economic anomalies on MISO TOs' Base ROE. Iowa Group concludes that without such evidence, the Presiding Judge's placement of the Base ROE at the midpoint of the zone of reasonableness's upper quartile does not constitute reasoned decision-making.[210]

93. Iowa Group asserts that the Presiding Judge's upward adjustment of the DCF zone of reasonableness's midpoint constitutes nothing more than an adjustment to normalize the DCF results so that they reflect the results that would be produced under "normal" financial market conditions. However, according to Iowa Group, the Commission has held that it does not make such adjustments as evidenced by its findings in *Portland Natural Gas Transmission System*.[211] Iowa Group states that the Commission instead explicitly rejected the argument that DCF data from the immediately preceding time period would be more appropriate and found that the cost of capital for the pipeline was representative of the time period in issue, measured by the DCF methodology without special consideration to the underlying turmoil in the financial markets. Iowa Group further states that when the same pipeline underwent another rate review in an immediately subsequent time period, the DCF results reflected those changes.[212] Iowa Group asserts that it is therefore not impermissible or problematic for the Commission to measure the cost of capital on the basis of prevailing capital markets, whether they be favorable or unfavorable to equity investors on the one hand, or consumers on the other. Iowa Group avers that the Commission should not make a practice of "normalizing" Base ROE allowances to take account of unusual or idiosyncratic conditions in the financial markets, especially here, where, as Ms. Lapson testified, the process of normalizing markets could last up to 30 years and the exact extent of alleged anomalies on the DCF model's inputs for the proxy companies is completely unknown.[213]

950-51 (D.C. Cir. 1981)).

[210] *Id.* at 22.

[211] *Id.* at 23-24 (citing *Portland Nat. Gas Transmission System*, Opinion No. 510-A, 142 FERC ¶ 61,198, at PP 219-220 (2013), *aff'g in relevant part*, Opinion No. 510, 134 FERC ¶ 61,129 (2011)).

[212] *Id.* at 24 (citing *see* Opinion No. 510, 134 FERC ¶ 61,129 at P 225; *Portland Nat. Gas Transmission System*, Opinion No. 524, 142 FERC ¶ 61,197, at PP 6, 290, and 323 (2013)).

[213] *Id.* at 24.

94. Iowa Group asserts that the expansive character of the generalizations relied upon in the Initial Decision to justify its upward adjustment of the DCF zone of reasonableness's midpoint, combined with their amorphous evidentiary connections to the DCF inputs and the lack of data quantifying the extent of the alleged economic anomalies impacts on those inputs, provide fertile ground for future claims for similar adjustments. Iowa Group argues that avoiding this result requires the Commission to reject the Presiding Judge's upward adjustment of the Base ROE on the ground that it does not withstand the rigorous scrutiny emphasized by Commissioner Honorable in Opinion No. 531-B.[214]

95. Joint Customer Intervenors assert that the current capital market conditions are neither "unprecedented" nor "unsustainable," and do not deviate from what is normal, but are instead evidence of a new and consistent normal.[215] Joint Customer Intervenors state that the capital market conditions cited in Opinion No. 531 have lasted at minimum four years and therefore have been shown to be sustainable. Joint Customer Intervenors refer to Mr. Solomon's analysis, which demonstrates that "[t]he consistency and persistence of the levels of capital costs over that . . . period demonstrate that current bond yields cannot be considered aberrational, but rather reflect a new and consistent normal."[216] Joint Customer Intervenors state that the current bond yields appear to be "part of a long-term decline in yields that began in the early 1980s."[217] Joint Customer Intervenors assert that former Federal Reserve Board Chairman, Dr. Benjamin Bernanke, has stated that "[l]ow interest rates are not a short-term aberration, but part of a long-term trend" and that "ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since."[218]

96. Joint Customer Intervenors contend that the Presiding Judge's focus on the actions of the Federal Reserve, rather than on the actual market conditions such as the relatively low level of interest rates and inflation, appears to have contributed to the determination

[214] *Id.* at 24-25.

[215] Joint Customer Intervenors Brief on Exceptions at 17-18 (citing Exh. JCI-1 at 27:16-19).

[216] *Id.* at 18 (citing Exh. JCI-1 at 27:16-19).

[217] *Id.* at 19 (citing Exh. JCI-4 at 27:5-7).

[218] *Id.* at 20-21 (citing Exh. JCI-6 at 1).

that anomalous market conditions existed.[219] Joint Customer Intervenors state that the Federal Reserve acted to stimulate the economy after the Great Recession, which Joint Customer Intervenors argue would tend to increase economic activity, inflation, and the opportunity cost of capital.[220] Joint Customer Intervenors assert that the Presiding Judge's reliance on the actions of the Federal Reserve as the cause of the alleged anomalous market conditions is unfounded because, without the actions of the Federal Reserve, inflation and the cost of capital could have been lower.[221]

97. According to Joint Customer Intervenors, Mr. Solomon demonstrated that, despite MISO TOs' claim that Federal Reserve bond purchases had made bond investments unavailable to investors interested primarily in yield, federal debt as a percentage of annual GDP has doubled since 2008.[222] Joint Customer Intervenors state that the Presiding Judge dismissed Mr. Solomon's exhibit because the questions raised therein were highly technical and there was a lack of expert testimony.

98. Joint Customer Intervenors also state that the Presiding Judge erred by holding that *Hope* and *Bluefield* require the Commission to distinguish between short- or long-term investors, and by finding that the evidence demonstrates that MISO TOs are only attracting short-term investors.[223] According to Joint Customer Intervenors, the Presiding Judge determined that an ROE can be considered too low if the capital made available to the company comes from the wrong type of investors. Joint Customer Intervenors assert, however, that a short-term investor selling its stock has to accept a price based on the expected long-term cash flow to be derived from the stock.[224]

99. Joint Customer Intervenors also point out that "[r]ates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as

[219] *Id.* at 23.

[220] *Id.* at 24 (citing Exh. JCA-1 at 6:9-15, 7:10-12; Exh. JCA-11 at 24:10-12.).

[221] *Id.* at 24.

[222] *Id.* at 25 (citing Exh. JCI-7).

[223] *Id.* at 26.

[224] *Id.* at 27 (citing *Williston Basin Interstate Pipeline Co*., 81 FERC ¶ 61,033, at P 61,175 (1997) (*Williston Basin*) ("even a short-term investor would be concerned about long-term growth . . . ."))."

invalid."[225] Joint Customer Intervenors state that the Initial Decision appeared to take a different view by acknowledging that "the cost to electric utilities of raising capital by issuing stock is also low" but nevertheless holding that "this does not mean that the [cost of equity] is low."[226] According to Joint Customer Intervenors, the Presiding Judge thereby found that an ROE set at the DCF midpoint would enable MISO TOs to raise capital, yet would be insufficient to attract long-term investors and thus would fail to comply with the Initial Decision's interpretation of *Hope* and *Bluefield*. Joint Customer Intervenors contend that the Presiding Judge failed to support the theory that the cost of equity is higher than the cost of raising capital, and assert that this theory is contrary to existing precedent.[227]

100. Joint Customer Intervenors also argue that the Presiding Judge erred by concluding that MISO TOs would not attract a sufficient number of long-term investors if the ROE were set at the midpoint of the DCF range of reasonableness. According to Joint Customer Intervenors, the Initial Decision suggested that a period of six years and eight months may qualify as short-term.[228] Joint Customer Intervenors argue that, if six years and eight months qualifies as short-term, the Presiding Judge effectively held that the midpoint of the DCF can only be relied upon when evidence demonstrates that most investors plan to hold their securities for at least seven years. Joint Customer Intervenors assert, however, that no court or regulatory agency has ever required such a showing.[229]

101. According to Joint Customer Intervenors, the Presiding Judge assumed that the supposed prevalence of short-term investors among utility stockholders is significant because short-term investors are likely to sell their stock as soon as the allegedly anomalous conditions change. Joint Customer Intervenors state that this assumption relied on Ms. Lapson's belief that it is anomalous for investors to buy and hold yield-producing securities when they expect interest rates to rise.[230] Joint Customer

[225] *Id.* at 27 (citing *Hope*, 320 U.S. 605).

[226] *Id.* at 27-28 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 215-216).

[227] *Id.* at 28 (citing *Boston Edison Co. v. FERC*, 885 F.2d 962, 965 (1st Cir. 1989) (holding that the DCF asks "what is the minimum amount that one must pay new investors . . . to offer the utility the money that it needs for investment")).

[228] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 177).

[229] *Id.* at 29.

[230] *Id.* at 35 (citing Initial Decision, 153 FERC ¶ 63,027 at P 146).

Intervenors argue, however, that the forecasts cited in the Presiding Judge predict interest rates to rise by 2019 and that it is hardly anomalous for investors to expect interest rates and other capital market parameters to change over the ensuing several years. Furthermore,
Joint Customer Intervenors note that the Presiding Judge stated that "the Federal Reserve's calibration of its increase in the federal-funds target rate . . . may delay the rate impact of normalization, but will not prevent the suddenness of that impact once short-term rates start to provide acceptable yield."[231] Joint Customer Intervenors argue that, even if the Presiding Judge is correct and a sudden selloff of utility stocks by short-term investors leaves MISO TOs with difficulty raising capital, MISO TOs have the right under FPA section 205 to file for increased rates and to put those increased rates into effect after 60 days. Joint Customer Intervenors contend that the Presiding Judge would effectively require customers to pay excessive rates for years to avoid the possibility that MISO TOs might collect insufficient rates for 60 days. Joint Customer Intervenors, therefore, assert that the Initial Decision thus failed to engage in "a balancing of the investor and the consumer interests."[232]

102. Joint Customer Intervenors also argue that the Presiding Judge erred in finding that the reliability of the DCF analysis in this proceeding should be called into question.[233] Joint Customer Intervenors assert that the Commission's two-step DCF methodology, when properly implemented, correctly measures the market cost of capital. Joint Customer Intervenors explain that the Commission's DCF methodology is based on three major components: the dividend, the price of common stock, and the expected dividend growth rate.[234] Joint Customer Intervenors state that the dividend is published by the company and the price of common stock is determined in the competitive marketplace, while growth rate forecasts are developed and published by independent entities that generally are relied on by investors in forming their future outlook. Joint Customer Intervenors assert that, as the DCF methodology is forward-looking and based on the expectations of investors, the DCF results reflect the reality of the capital markets and the actual market cost of equity capital.[235]

[231] *Id.* at 35-37 (citing Initial Decision, 153 FERC ¶ 63,027 at P 199).

[232] *Id.* at 29-30 (citing *Hope*, 320 U.S. 345).

[233] *Id.* at 21 (citing Initial Decision, 153 FERC ¶ 63,027 at P 228).

[234] *Id.* at 21-22 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 15).

[235] *Id.* at 22-23.

103. According to Joint Customer Intervenors, the Presiding Judge relied heavily on the finding of anomalous capital market conditions in Opinion No. 531, yet failed to recognize that the record established in the instant proceeding differs from that before the Commission in Opinion No. 531 and compels the conclusion that capital market conditions cannot be considered anomalous in the relevant period.[236] Joint Customer Intervenors assert that the Presiding Judge considered arguments that were not found in Opinion No. 531 in support of MISO TOs' contention that conditions were anomalous, but dismissed arguments that conditions were not anomalous because the Commission had not accepted such arguments in Opinion No. 531.[237]

104. Joint Customer Intervenors contend that the record in the instant proceeding includes the following factors that, in contrast to the finding of anomalous market conditions in Opinion No. 531, indicate that economic conditions have not been aberrational: (1) the six-month average ten-year U.S. Treasury bond yield was above two percent by 28 basis points; (2) the unemployment rate dropped substantially to below six percent; (3) the economy expanded and the stock market was strong; (4) the Federal Reserve had substantially wound down its Quantitative Easing initiative; and (5) inflation remained below the Federal Reserve's Open Market Committee's two percent target level.[238] Joint Customer Intervenors argue that the Presiding Judge did not closely examine these conditions or explicitly reject the evidence that the market conditions do not warrant an upper-midpoint ROE for MISO TOs and thus erred in finding that market conditions were anomalous.[239]

105. Joint Customer Intervenors argue that the evidence presented in the hearing failed to demonstrate a correlation between the ROE and the level of transmission investment. They state that MISO TOs' witness, Mr. Kramer, was not able to say whether a base ROE greater than 12.38 percent would have resulted in the construction of more new projects.[240] Joint Customer Intervenors also claim that Mr. Kramer was unable to provide evidence of whether a lower base ROE would have resulted in the same level of benefits.[241] Joint Customer Intervenors also argue that the Presiding Judge relies upon

[236] *Id.* at 15-16 (citing Opinion No. 531, 147 FERC ¶ 61,234 at PP 115, 116, 119).

[237] *Id.* at 16 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 205).

[238] *Id.* at 17 (citing Exh. JCI-1 at 26:12-23).

[239] *Id.*

[240] *Id.* at 52-53 (citing Exh. JCI-14 at 1).

[241] *Id.* at 53 (citing Exh. JCI-13 at 1).

the statements of MISO TOs' witness, Ms. Lapson, asserting that an ROE reduction would result in a reduction in earnings and cash flow, and that credit ratings might be affected.[242] Joint Customer Intervenors claim, however, that no party provided evidence to suggest that the base ROE that Joint Customer Intervenors argue for would impair transmission investment in MISO.[243]

106. Joint Customer Intervenors also argue that the capital market conditions during the study period in the instant proceeding were similar to those addressed in the May 12, 2015 Entergy Initial Decision,[244] in which the Presiding Judge found that capital market conditions were not anomalous. Therefore, Joint Customer Intervenors argue that the Presiding Judge erred in finding such conditions were anomalous here.[245]

107. OMS states that evidence submitted by Trial Staff showing historical bond yields going back to the year 1919 leads to the conclusion that the low bond yields seen during the study period in this docket are not unprecedented.[246] OMS also states that the Presiding Judge essentially found that capital market conditions are "anomalous" because they are unsustainable, and they are unsustainable because either interest rates will go up or investors will stop expecting them to go up. OMS states that the simple fact is that market conditions change over time because the market forces that shape those conditions change over time. Furthermore, OMS contends that whether or not investors perceive the Federal Reserve's accommodative monetary policy as temporary is beside the point because, it can credibly be argued, *all* market forces are temporary.[247] OMS argues that what actually matters is whether investors expect that the eventual ending of the Federal Reserve's current program of accommodative actions will significantly impact their investments, such as by causing interest rates and bond yields to spike. OMS contends that the answer is far less certain than the Initial Decision suggests.

[242] *Id.* at 54 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 463-470).

[243] *Id.*

[244] *Entergy Ark., Inc.*, 151 FERC ¶ 63,008, at P 89 (2015) (Entergy Initial Decision).

[245] Joint Customer Intervenors Brief on Exceptions at 24-25.

[246] OMS Brief on Exceptions at 13-14 (citing Exh. S-1 at 12).

[247] *Id.* at 16 (emphasis supplied).

108. OMS also states that the record evidence casts considerable doubt on the extent to which Federal Reserve policies actually affect the inputs to a DCF study. For example, OMS contends that the record includes an article written by Dr. Bernanke questioning the Federal Reserve's ability to affect interest rates over the long-term, and stated that real interest rates are determined by a broad array of economic factors (including prospects of economic growth), not solely by Federal Reserve actions.[248] In addition, OMS states that the Presiding Judge agrees with MISO TOs' contention that Federal Reserve policy decreased yields on long-term U.S. Treasury bonds by increasing the demand for (and prices of) those securities, but it ignores the *supply* side of that equation.[249] OMS states that overlapping in time with Quantitative Easing, but swamping it in magnitude, large Federal deficits were being financed by the issuance of new federal debt securities, to the extent that Federal debt as a share of Gross Domestic Product more than doubled after 2008.[250] OMS argues therefore that even if Quantitative Easing bond purchases exerted a downward pressure on bond yields (by pulling down the supply of U.S. Treasury bonds, driving up their price and pushing down yields), new Federal bond issuances to finance the growing deficit had the opposite effect; by adding to the supply of Federal debt securities, prices were pushed down and yields were driven up.

109. OMS states that the Presiding Judge found that, as a result of falling interest rates and dividend yields, the cost to electric utilities of raising capital by issuing stock is low.[251] OMS states, however, that the Presiding Judge erred by rejecting the conclusion that logically follows from the finding – namely, that the costs of common equity for utilities is also low. OMS argues that the Presiding Judge's findings in this regard rely on the premise that the cost of equity must satisfy the total return requirements of a long-term investor to satisfy *Hope* and *Bluefield*.[252] OMS states that none of the testimonies prepared by MISO TOs' expert witnesses' distinguish between the required returns of long-term versus short-term investors to satisfy the standards in *Hope* and *Bluefield*. Rather, OMS states that the distinction was first included in the record during the hearing as part of the Presiding Judge's clarification question to Ms. Lapson. OMS contends that Complainants and supporting intervenors had no opportunity to include expert

[248] *Id.* at 23 (citing Exh. JCI-6 at 2).

[249] *Id.* at 24 (citing Initial Decision, 153 FERC ¶ 63,027 at P 123 (emphasis supplied)).

[250] *Id.* (citing Exh. JCI-7 at 84, figure 1).

[251] *Id.* at 25 (citing Initial Decision at P 215).

[252] *Id.* at 25-26 (citing Initial Decision, 153 FERC ¶ 63,027 at P 210).

testimony in the record to address this new distinction and whether it is at all relevant to determining the cost of equity of MISO TOs. OMS states that Complainants and supporting intervenors could not have anticipated such issues being raised during the hearing because: (1) the DCF does not distinguish between "short-term" and "long-term" investors; and (2) there is no Commission precedent discussing the proposition that there is a difference between the results of the DCF study and the true cost of equity.

110. OMS states that the finding that the DCF analysis does not reflect the true cost of equity because it does not satisfy the requirements of the long-term investors was developed by the Presiding Judge who, according to OMS, appears to be uncertain himself about the validity of this theory.[253] OMS states that the Commission should not affirm rulings that rely on such equivocal findings. OMS states that there is no credible evidence in the record showing that investors no longer care about dividend growth and continue to invest in the utility stock just for the yield. Moreover, OMS contends that if the Presiding Judge's theory is credited, then the Presiding Judge contradicted himself in discarding as illogical two low-end results that exceeded the study-period Baa utility bond yield of 4.65 percent, but did so by less than 100 basis points.[254] OMS states that the basis of the standard 100 basis point screen is a finding that investors in utility stocks require appreciably more yield than utility bonds provide.[255]

111. OMS states that investor behavior belies any expectation of sharply increased interest rates. OMS states that MISO TOs' case is grounded on the proposition that investors are (and, during the study period, were) expecting an impending end to the capital market conditions that have prevailed for the past several years, once the Federal Reserve begins to normalize its post-recession monetary policies.[256] OMS states that

[253] *Id.* at 27 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 216 (the total returns of proxy companies "are not necessarily" equivalent to their cost of equity), 218 (expectations of dividend growth "may" not be guiding investment decisions; investors "may" be purchasing stock only for the current yield; the proxy group stock prices "may" not reflect long-term investors satisfaction)).

[254] *Id.* at 27-28 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 65, 158).

[255] *Id.* at 28 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 122 ("The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt.")).

[256] *Id.* at 20 (citing Initial Decision, 153 FERC ¶ 63,027 at P 222).

MISO TOs also contend that investors expect a sharp rise in interest rates and bond yields – an expectation that renders the current conditions "anomalous." OMS argues that, while the Initial Decision accepts both premises of MISO TOs' case, there is a significant flaw in MISO TOs' theory. OMS contends that a fundamental assumption of the DCF method is that investors are rational actors who manifest their knowledge and expectation about the market through the prices they are willing to pay for stock. OMS states that if investors in utility stocks are expecting an imminent jump in interest rates due to Federal Reserve policy normalization, their rational response would be for them to sell those stocks before the increases in interest rates begin. If the expectation were sufficiently widespread and enough investors pursue the path of rational self-interest, OMS contends that utility stock prices would fall as shares are sold into the market, which would cause the dividend yields on those stocks to increase. But, OMS argues that the record evidence shows that simply has not happened. According to OMS, that yields on utility stocks have not increased implies that investors have elected not to sell their shares, a decision that can only mean that investors expect that the normalization of Federal Reserve monetary policy will be gradual and have little to no adverse impacts on the value of their holdings.[257]

112. OMS states that the Presiding Judge's finding that, during the study period, "many investors have expected that the Federal Reserve will normalize current market-capital conditions, and that interest rates will rise significantly over the next few years," is contradicted by evidence in the record.[258] OMS contends that the record demonstrates that, since the Federal Reserve ended its Quantitative Easing Program in October 2014, bond yields and interest rates changed very little.[259] OMS states that, contrary to the Presiding Judge's findings, the record shows that during the study period there was no clear consensus within the investment community as to what specific actions the normalization of Federal Reserve policy would entail, or what impact those actions might have on interest rates and bond yields. OMS states that, prior to or within the study period, the Federal Reserve reassured the investment community that any change in its accommodative monetary policy would not be drastic. OMS states the January 2015 minutes to the Federal Open Market Committee, cited by Ms. Lapson and included in the record, include a resolution to maintain the Federal Reserve policy of reinvesting principal payments from its holdings of agency debt and agency mortgage backed securities because maintaining a sizable level of long-term securities "should help

[257] *Id.* at 19-20.

[258] *Id.* at 16-17 (citing Initial Decision, 153 FERC ¶ 63,027 at P 222).

[259] *Id.* at 17 (citing Exh. S-1 at 63:21-22; Exh. JCI-1 at 27:9-14).

maintain accommodative financial conditions."[260] OMS contends that, although the Presiding Judge interpreted the Federal Open Market Committee minutes to support a finding that investors expect interest rates to rise because the minutes indicate that "normalization" could start at any time, the minutes can just as easily be understood to say that, even if investors believed that a change in the Federal Reserve's accommodative monetary policies was a certainty and that it would lead to higher interest rates, investors also knew that any such policy changes (1) could take some time to implement, and (2) would likely be carefully measured (not dramatic or sudden) because the Federal Reserve also was charged with pursuing a set of important economic objectives that were tied to promoting recovery from the recent recession.

c. <u>Brief Opposing Exceptions</u>

113. MISO TOs argue that the record demonstrates the existence of anomalous capital market conditions affecting DCF inputs and results and ask the Commission to affirm the Initial Decision's finding of anomalous market conditions.[261] MISO TOs point to the fact that the Federal Reserve holds "massive amounts" of U.S. Treasury bonds and mortgage-backed securities. They argue that these holdings cause bond prices to spike and yields to decline and suppress the short-term federal funds target rate, which leads fixed-income investors to seek yield in higher risk assets, such as electric utility stocks. MISO TOs state that these circumstances result in utility equity price increases and yield decreases.[262] In response to arguments that investors were aware of the Federal Reserve's policies during the relevant period and that the capital market has effectively settled into a "new normal" and cannot be considered anomalous, MISO TOs argue that these arguments conflate the duration of anomalies with the existence of anomalies.[263] Further, MISO TOs assert that the fact that these conditions have persisted longer than anticipated does not undercut the Presiding Judge's conclusion that investors expect the Federal Reserve to normalize and for interest rates to eventually rise.[264]

114. MISO TOs further argue that the DCF model is not infallible and dispute arguments that the DCF model accurately estimates the cost of equity capital irrespective

[260] *Id.* at 19-20 (citing Exh. S-10 at 20).

[261] MISO TOs Brief Opposing Exceptions at 7-8.

[262] *Id.* at 8.

[263] *Id.* at 9-10.

[264] *Id.* at 10.

of prevailing capital market conditions. MISO TOs argue that, in Opinion No. 531-B, the Commission stated that "all methods of estimating the cost of equity are susceptible to error when the assumptions underlying them are anomalous."[265] MISO TOs argue that accepting the opposing parties' contrary arguments here would disregard the Commission's explicit instruction in the Hearing Order that the participants' evidence and DCF analyses conform to Opinion No. 531.[266]

115. Moreover, MISO TOs argue that the Presiding Judge demonstrated how anomalies can undermine a model's ability to accurately estimate a utility's cost of equity and raised sufficient doubt about the DCF results' reliability to compel examination of alternative benchmarks.[267] In response to arguments that the Presiding Judge's analysis "failed to prove distortion of DCF inputs or quantify their impact," MISO TOs argue that Opinion Nos. 531 and 531-B require no such standard of proof, only sufficient evidence to question the reliability of the DCF midpoint.[268] MISO TOs further state that the Presiding Judge noted that the DCF midpoint will not be just and reasonable if it does not appropriately represent utilities' risks.[269]

116. MISO TOs further note that the Presiding Judge's analysis clearly links capital market conditions and the DCF model and explains that *Hope* and *Bluefield*'s dual standards can only "be rationally applied" in the context of long-term investment decisions, since short-term investors have less interest in a utility's financial integrity and creditworthiness.[270] MISO TOs contend that the Presiding Judge found credible testimony that capital market anomalies have caused investors to deploy capital in ways inconsistent with the objectives and assumptions underlying *Hope* and *Bluefield* and the DCF model. This evidence attested that historically low interest rates available from conventional long-term investments are driving investors to better yielding, riskier

[265] *Id.* at 11 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50).

[266] *Id.* at 12 (citing Hearing Order, 149 FERC ¶ 61,049 at P 186).

[267] *Id.* at 12.

[268] *Id.* at 12.

[269] *Id.* at 13.

[270] *Id.* at 14.

alternatives, such as utility equities.[271] MISO TOs assert that, consequently, utilities' stock prices have risen and associated yields have declined.[272]

117. MISO TOs also respond to arguments that the Presiding Judge's analysis reflects an interpretation of *Hope* and *Bluefield* that is improperly applied to the DCF and arguments that the Presiding judge's findings cannot "be squared" with the correlation between the cost of debt and equity and the direction relationship between low interest rates, low dividend yields, high equity prices, and a low cost of equity.[273] MISO TOs argue that, in the context of establishing returns for regulated transmission owners, the concepts of capital attraction and financial integrity only have meaning in the long-term horizon as transmission assets take years to plan and construct and are often in service for decades.[274]

118. MISO TOs also take issue with attempts to marginalize the testimony of Ms. Lapson, arguing against the use of the midpoint DCF value by citing to opposing parties' own witnesses who acknowledge the effect of current capital market conditions on DCF inputs. MISO TOs argue, in short, that there is clear evidence that the Federal Reserve's historically unprecedented monetary policies have altered normal investment behavior.[275]

d. Commission Determination

119. We affirm the Presiding Judge's conclusions, though we do not adopt the totality of his reasoning, concerning anomalous capital market conditions. For the reasons discussed below, we conclude that the record in this proceeding demonstrates the presence of unusual capital market conditions, such that we have less confidence that the central tendency of the DCF zone of reasonableness (the midpoint in this case) accurately reflects the equity returns necessary to meet *Hope* and *Bluefield*.

120. As the Commission found in Opinion No. 531, the DCF methodology, like all cost of equity estimation methodologies, "may be affected by potentially unrepresentative

[271] *Id.* at 14.

[272] *Id.* at 14.

[273] *Id.* at 15 (citing Trial Staff Brief on Exceptions at 33-35).

[274] *Id.* at 16.

[275] *Id.* at 17.

financial inputs" as a result of unusual economic conditions.[276] As Roger A. Morin states in his treatise, *New Regulatory Finance*,[277] "by relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return." Therefore, it is reasonable, under those conditions, to consider the results of alternative methods for estimating the cost of equity when determining whether a mechanical reliance on the central tendency of the DCF-produced zone of reasonableness produces a just and reasonable ROE.[278] Our finding of anomalous market conditions does not, by itself, justify awarding an ROE above the central tendency of the DCF-produced zone of reasonableness. Rather, that finding supports a consideration of other cost of equity estimation methodologies in determining whether mechanically setting the ROE at the central tendency satisfies the capital attraction standards of *Hope* and *Bluefield*.

121. The record in this proceeding raises the same concerns regarding capital market conditions that the Commission identified in Opinion No. 531. Bond yields remained at historically low levels during the study period. For example, the yield on 10-year U.S. Treasury bonds, which the Commission noted in Opinion No. 531[279] was below two percent in that case and had not been below three percent since the 1950s, was at 2.07 percent[280] during the study period. Also, the yield on short-term U.S. Treasury bonds was historically low, ranging from zero to 0.25 percent.[281] Additionally, we note that, while the Federal Reserve has ended the Quantitative Easing program under which it was purchasing unprecedented levels of U.S. Treasury bonds and mortgage-backed securities,[282] the Federal Reserve continues to hold approximately $4.25 trillion[283] of

[276] Opinion No. 531, 147 FERC ¶ 61,234 at P 41. *See also* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50 ("all methods of estimating the cost of equity are susceptible to error when the assumptions underlying them are anomalous").

[277] *New Regulatory Finance* 28 (Public Utilities Reports, Inc. 2006).

[278] *See, e.g.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 145, *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50.

[279] Opinion No. 531, 147 FERC ¶ 61,234 at n.285.

[280] *See* Exh. S-5 at 8.

[281] *See* Exh. MTO-16 at 22-23.

[282] *See id.* at 17-20.

those bonds, a level only slightly below recent record highs, and is reinvesting the principal payments from those holdings to purchase approximately $16 billion of mortgage-backed securities per month and rolling over the U.S. Treasury bonds at auction.[284] This record evidence is indicative of the same type of unusual capital market conditions that the Commission found concerning in Opinion No. 531. Parties point out that certain capital market conditions have changed since Opinion No. 531, including the winding down of Quantitative Easing, the slight increase in U.S. Treasury bond yields, the lower unemployment rate, and strong stock market performance. Though the Commission noted certain economic conditions in Opinion No. 531, the principal argument was based on low interest rates and bond yields, conditions that persisted throughout the study period. Consequently, we find that capital market conditions are still anomalous as described above, and, therefore, we disagree with Iowa Group's assertion that there is not substantial evidence to justify a potential adjustment.

122. Because the evidence in this proceeding indicates that capital markets continue to reflect the type of unusual conditions that the Commission identified in Opinion No. 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with *Hope* and *Bluefield*.[285] We conclude that the fact that these conditions have persisted over the approximately two years since the end of the study period adopted in Opinion No. 531 does not, in and of itself, mean that these conditions are not anomalous. Ms. Lapson describes the model risk associated with the reliance on mechanical application of a model and discusses how it is necessary to test model outcomes against other investment benchmarks as a check.[286] As the Commission found in Opinion No. 531, under these circumstances, we have less confidence that the midpoint of the zone of reasonableness in this proceeding accurately reflects the equity

[283] *See id*. at 18, 23.

[284] *See* Exh. MTO-1 at 22.

[285] Opinion No. 531 states:

> There is 'model risk' associated with the excessive reliance or mechanical application of a model when the surrounding conditions are outside of the normal range. 'Model risk' is the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled.

147 FERC ¶ 61,234 at n.6.

[286] *See* Exh. MTO-16 at 30-31.

returns necessary to meet the *Hope* and *Bluefield* capital attraction standards.[287] We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies and state-commission approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.

123. Complainants and intervenors make a number of arguments against the Presiding Judge's determination that anomalous market conditions justify examining alternative methodologies and state-commission approved ROEs to assess whether the ROE should be placed in the upper half of the zone of reasonableness. Such arguments, discussed in more detail below, largely pertain to the Presiding Judge's reasoning, such as the distinction between short-term and long-term investors, reasoning that we do not adopt even though we reach the same conclusions. Additionally, because we base our conclusion on a different rationale than the Presiding Judge, we need not consider arguments regarding the Presiding Judge's consideration of evidence on which we do not rely.

124. Parties argue that the record does not support the Presiding Judge's finding that capital market conditions during the study period are anomalous, either generally or based on the Presiding Judge's definition of anomalous as "unprecedented and unsustainable." We do not adopt that definition so we do not need to consider those arguments here. As described above, evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous. Although the record indicates that there was a past period of similarly low interest rates, it occurred more than sixty years ago. Similarly, while Complainants provide evidence that interest rates have been trending downwards, the current levels may be so low as to cause irregularities in the outputs of the DCF. Despite such yields remaining low for several years, we find that they are anomalous and could distort the results of the DCF model.

125. Parties also argue that MISO TOs have not presented evidence that the actions of the Federal Reserve directly affected DCF methodology results. Specifically, Trial Staff argues that there is no credible evidence that any of the DCF inputs have been distorted by purportedly anomalous capital market conditions. As described above, we find that the relevant anomalous capital market conditions cited in Opinion No. 531 are still present in this proceeding. Moreover, because the analytical approach we use here, and which we used in Opinion No. 531, gives us confidence that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*, a direct causal analysis linking specific capital

[287] Opinion No. 531, 147 FERC ¶ 61,234 at P 145.

market conditions to particular inputs or assumptions in the DCF model is not necessary. Consistent with Opinion No. 531, we find that the DCF methodology is subject to model risk of providing unreliable outputs in the presence of unusual capital market conditions.[288] The Commission has not required a mathematical demonstration of how each anomalous capital market condition specifically distorts the DCF analysis and it is uncertain whether such an analysis is even possible given the complexities of capital markets and how various phenomena could affect the DCF methodology results.[289] For that reason, in the presence of anomalous capital market conditions, the Commission examines other evidence, namely the results of alternative methodologies and state-commission approved ROEs to assess the reasonableness of the results of the DCF methodology. We find that the record contains sufficient evidence of anomalous capital market conditions.

126. We also disagree with arguments regarding the lack of effect of Federal Reserve's actions, including OMS' assertion that the effect on capital market conditions of increases in the Federal Reserve's holdings of U.S. Treasury bonds has been more than counteracted by large increases in federal debt outstanding during the same period. OMS has provided no evidence showing that increases in the amount of U.S. Treasury bonds directly counteract and nullify the effect of direct capital market interventions by the Federal Reserve.[290] Similarly, no party has shown that other global events or investor behavior caused the anomalous capital market conditions. Again, the fact remains that capital market conditions are anomalous, such that mechanical application of the DCF methodology could produce unreasonable results.

127. Parties raise numerous objections to the Presiding Judge's distinction between short-term and long-term investors in finding that the midpoint ROE produced by the application of the DCF methodology is insufficient. Because we do not adopt this

[288] Opinion No. 531, 147 FERC ¶ 61,234 at n.286.

[289] While we do not adopt the Presiding Judge's rationale concerning the specific causal link between the anomalous capital market conditions and the results of the DCF model, we acknowledge that the Presiding Judge's rationale might have merit and our determination here is without prejudice to that rationale. However, given the difficulty of establishing a causal relationship between complex capital market conditions and the results of any particular financial model, we are not persuaded that the record evidence in this proceeding is adequate to definitively conclude that the Presiding Judge's rationale explains how the current capital market conditions are impacting the DCF model.

[290] Further, we note that, even if more U.S. Treasury bonds are available, the low interest rates in the record are equally applicable to those bonds.

element of the Presiding Judge's reasoning, we need not respond to these objections. Instead, we find that where anomalous market conditions give us reason to have less confidence in DCF methodology outputs, it is reasonable to consider alternative methodologies and state-commission approved ROEs in determining a just and reasonable ROE. Our not adopting this reasoning also renders moot assertions regarding a contradiction between finding that short-term investors require lower returns and maintaining the 100-basis point low end screen in the DCF methodology.

128. Complainants are correct that the record does not contain evidence that economic conditions have "negatively impacted" the ability of MISO TOs to raise capital.[291] MISO TOs have been raising capital successfully with a 12.38 percent ROE, which we determine here is excessively high. However, MISO TOs bear no obligation to demonstrate difficulty raising capital in excess of the ROE adopted by the Initial Decision. Furthermore, there is record evidence that a decrease in ROE of that magnitude – a 309 basis point reduction from 12.38 percent to 9.29 percent –could undermine the ability of MISO TOs to attract capital for new investment in electric transmission.[292]

129. Parties also argue that, because the impending rise of interest rates will not happen suddenly or soon, the returns provided by the midpoint of the DCF analysis are sufficient. They also argue that rational investors would not invest in assets that are assumed to be likely to lose value soon. Such arguments are inapplicable to the rationale adopted in this order. Our reasoning, unlike the Presiding Judge's, does not rely on assessing investor expectations of the specific timing of potential interest rate increases that could affect utilities' future ability to raise capital. We do not find that the ROE needs to be sufficient for when interest rates increase. Similarly, we are not finding that investors are necessarily making investments without considering the potential effects on stock valuation of likely future interest rate increases. Rather, we find that current capital market conditions may cause the mechanical application of the DCF methodology to produce an ROE that does not meet the requirements of *Hope* and *Bluefield*.

[291] Complainants Brief on Exceptions at 33.

[292] Exh. MTO-1 at 7. For example, Ms. Lapson pointed out a June 11, 2013 Wolf Research paper that stated "Material reductions in the base ROE could lower the quality of and divert capital away from the transmission business, given its generally riskier profile than that for state-regulated utility businesses, such as distribution and generation. Moreover, investors could deploy capital to infrastructure projects with higher allowed returns, such as Commission-regulated natural gas pipelines, or to other industries generally."

130. Similarly, we disagree with Iowa Group's argument that any upward adjustment represents an improper attempt to "normalize" the DCF results to reflect normal capital market conditions. Any finding of anomalous capital market conditions and subsequent adjustments represents an attempt to counteract imprecision in the DCF model caused by capital market conditions and not a results-oriented attempt to raise the ROE to what it more typically is.

131. Trial Staff and others also argue that, if and when capital market conditions change, MISO TOs can request an increase in their effective ROE. As described above, anomalous market conditions may skew the current outputs of the DCF methodology, such that the mechanical application of the DCF methodology could provide an unjust and unreasonable ROE. Subsequent requests for rate increases would not address this shortcoming. The Commission also addressed this argument in Opinion 531-B where it found that transmission owners' "ability to subsequently request a rate increase if economic conditions change does not excuse the Commission from establishing an ROE under FPA section 206 that meets the requirements of *Hope* and *Bluefield*."[293]

132. We also disagree with arguments that the DCF methodology fully incorporates available information and investor expectations such that capital can be raised as inexpensively as the DCF results suggest. We find that such an outcome may not be the case due to model risk inherent in the DCF methodology in the presence of unusual market conditions. The finding that mechanical application of the DCF methodology may produce results inconsistent with *Hope* and *Bluefield* in certain circumstances is not inconsistent with the efficient market theory underlying the typical application of the DCF methodology in normal circumstances. Thus, consistent with the rationale explicated in Opinion No. 531, we disagree with Joint Customer Intervenors' assertion that the Presiding Judge erred in questioning the reliability of the DCF methodology in this proceeding based on the sources of information employed by this methodology.

133. We disagree with Joint Customer Intervenors' contention that the findings of the Presiding Judge in the Entergy Initial Decision are relevant to the ROE determination in this proceeding. Regardless of the timing of the study period in that proceeding, the findings in an initial decision, unless affirmed by the Commission, are not precedential.

134. We also disagree with Iowa Group's contention that any finding of anomalous capital market conditions and potential subsequent upward adjustment of the ROE is a "default" policy. In each proceeding, the Commission will evaluate the facts during the relevant period to determine whether capital market conditions are unusual and, if so, the Commission will consider alternative benchmark methodologies and state commission-

[293] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50.

approved ROEs as additional evidence that might suggest that a mechanical application of the DCF results in an ROE insufficient to satisfy the requirements of *Hope* and *Bluefield*.[294] We also disagree with Iowa Group's assertion that there is no evidence that anomalous market conditions apply equally to DCF inputs from each member of the proxy group. This argument implies that MISO TOs would need to provide detailed studies of the effects of capital market conditions for each member of the proxy group, which would be unduly burdensome, if not impossible. Moreover, such a showing is unnecessary since capital market conditions apply across the entire economy and are not specific to individual utilities.

135. MISO TOs presented three alternative methodologies for estimating the cost of equity in this proceeding: a risk premium analysis, a capital asset pricing model (CAPM) analysis, and an expected earnings analysis. These alternative methodologies are the same ones that the Commission relied upon in Opinion No. 531 to corroborate the Commission's determination that a mechanical application of the DCF methodology results in an ROE that does not satisfy *Hope* and *Bluefield*. MISO TOs' risk premium analysis based upon Commission-authorized ROEs indicates that the Operating Companies' cost of equity is 10.36 percent.[295] MISO TOs' CAPM analysis produces a midpoint cost of equity estimate of 10.06 percent once an adjustment for the effect of firm size is made.[296] MISO TOs' expected earnings analysis produces a midpoint ROE range of 11.99 percent. Thus, all three alternative methodologies produce cost of equity estimates substantially in excess of the 9.29 percent midpoint of the zone of reasonableness produced by the DCF analysis in this case. As the Commission did in Opinion No. 531, we find that these analyses are informative and corroborate our decision to place MISO TOs' ROE at the central tendency of the upper half of the zone of reasonableness produced by our DCF analysis of the proxy group companies, rather than the midpoint.

136. In addition, the record indicates that all of the current state ROEs exceeded the 9.29 percent midpoint of the DCF zone of reasonableness in this case. The midpoint of the current state ROEs is 9.95 percent.[297] As the Commission explained in Opinion No. 531, in situations where our DCF methodology produces ROEs below those

[294] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 145.

[295] Exh. MTO-29 at 1.

[296] *See* Exh. MTO-1 at 95:9-18.

[297] Exh. MTO-42 at 1-2. *See* Exh. MTO-16 at 52-56. Ms. Lapson eliminated a Base ROE of 10.95 percent as an outlier.

approved at the state level, for functions that are riskier than the state-regulated functions, such a relationship might indicate that a mechanical application of the DCF methodology with the use of the central tendency of the resulting zone of reasonableness will not satisfy the requirements of *Hope* and *Bluefield*.

137. As the Commission found in Opinion No. 531, in considering these other methodologies and the ROEs allowed by state commissions, we do not depart from our use of the DCF methodology; rather, due to the presence of unusual capital market conditions, we find it appropriate to look to other record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness produced by the DCF methodology.[298] Below, we address the participants' arguments against each of MISO TOs' alternative ROE methodologies.

2. <u>CAPM</u>

138. Investors use CAPM analysis as a measure of the cost of equity relative to risk.[299] The CAPM methodology is based on the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. Specifically, the CAPM methodology determines the cost of equity by taking the "risk-free rate" and adding to it the "market-risk premium" multiplied by "beta."[300] The risk-free rate is represented by a proxy, typically the yield on 30-year U.S. Treasury bonds.[301] Betas, which are published by several commercial sources, measure a specific stock's risk relative to the market. The market risk premium is calculated by subtracting the risk-free rate from the expected return. The expected return can be estimated either using a backward-looking approach, a forward-looking approach, or a survey of academics and investment professionals.[302] A CAPM analysis is backward-looking if the expected return is determined based on historical, realized returns.[303] A CAPM analysis is forward-looking if the expected return is based on a DCF study of a large segment of

[298] Opinion No. 531, 147 FERC ¶ 61,234 at P 146.

[299] *Id.* P 147.

[300] Roger A. Morin, *New Regulatory Finance* 150 (Public Utilities Reports, Inc. 2006).

[301] *Id.* at 151.

[302] *Id.* at 155-162.

[303] *Id.* at 155-156.

the market.[304] Thus, in a forward-looking CAPM analysis, the market risk premium is calculated by subtracting the risk-free rate from the result produced by the DCF study.[305]

139. In this proceeding, MISO TOs submitted a forward-looking CAPM analysis of each company in the proxy group using the 2.7 percent 30-year U.S. Treasury bond yield for the risk-free rate, beta values for each proxy company reported by Value Line, and a market risk premium based on a DCF study of all dividend-paying companies in the S&P 500.[306] In that DCF study, MISO TOs added the weighted average dividend of those companies (2.4 percent) to the average of the weighted average growth rates projected for the companies by IBES and Value Line (8.9 percent). This resulted in a uniform cost of equity for the dividend-paying companies in the S&P 500 of 11.3 percent. The MISO TOs then subtracted from that figure the 2.7 percent risk-free rate to obtain a risk premium of 8.6 percent. The MISO TOs multiplied this risk premium by the beta listed for each proxy company by Value Line and added the risk-free rate to that product. This CAPM analysis produces an unadjusted ROE range of 7.86 percent to 10.87 percent for the proxy group, with a midpoint value of 9.37 percent.

140. However, after adjusting for the effect of each proxy company's size, MISO TOs' CAPM analysis produced an ROE range of 7.50 percent to 12.61 percent, with a midpoint value of 10.06 percent.[307] MISO TOs' witness, Dr. Avera, explained that the "size adjustment reflects the fact that differences in investors' required rate of return that are related to firm size are not fully captured by beta."[308] Dr. Avera based his size adjustments on data contained in a table published in Morningstar Inc.'s (Morningstar) "2015 Ibbotson SBBI Market Report." The table adjusts each proxy company's cost of equity based on its size, reducing the unadjusted cost of equity of larger companies, while increasing those of smaller companies.[309]

[304] *Id.* at 159-160.

[305] *See id.* at 150, 155.

[306] Exh. MTO-1 at 97-98.

[307] Initial Decision, 153 FERC ¶ 63,027 at P 264 (citing Exh. MTO-30 at 1).

[308] Exh. MTO-1 at 98.

[309] Exh. MTO-30 at 1.

a. Initial Decision

141. The Presiding Judge determined that the CAPM model offered by Dr. Avera was credible and supported allowing MISO TOs to earn a base ROE above the 9.29 percent midpoint of the zone of reasonableness.[310] The Presiding Judge explained that Dr. Avera's model was "substantially similar" to the CAPM that the Commission found useful in determining the placement of the base ROE in Opinion No. 531. The Presiding Judge rejected Mr. Gorman's contention that the growth rate used for the DCF analysis in Dr. Avera's CAPM was unsustainable and should be based, at least in part, on long-term growth rates, noting that the Commission had rejected this argument in Opinion No. 531-B on the grounds that the long-term growth rate does not necessarily apply to a curated set of large companies, like those included in the S&P 500. The Presiding Judge also rejected Mr. Gorman's arguments that Morningstar does not make size adjustments for companies with betas of less than 1.0, including public utilities, concluding that these arguments were not born out by the Morningstar data.[311]

142. The Presiding Judge also rejected Mr. Gorman's contention that, based on the utility industry's low beta, Morningstar also makes a downward "industry premium" adjustment that offsets any upward adjustment for size.[312] Mr. Gorman contended that Morningstar's SBBI 2013 Valuation Yearbook recommends an industry premium, as well as a size adjustment. Mr. Gorman stated that Morningstar recommends a negative industry premium adjustment for the electric-utility industry of between 3.4 percent and 4.09 percent. However, the Presiding Judge found that, on cross-examination, Mr. Gorman admitted that the Morningstar industry premium to which he referred was used for its "buildup method" of estimating cost of equity, and is not used to develop a CAPM.

143. The Presiding Judge also rejected the CAPM analysis advanced by Mr. Gorman and Mr. Hill, noting that it differed in several material respects from the CAPM that Commission relied upon in Opinion No. 531. The Presiding Judge noted, for instance, that this analysis did not use forward-looking data for its risk premium, nor did it use the 30-year U.S. Treasury bonds as its proxy for the risk-free rate of return, and that this analysis made no effort to adjust for the capitalization of the companies considered.[313]

[310] Initial Decision, 153 FERC ¶ 63,027 at P 313.

[311] *Id.* PP 268-269.

[312] *Id.* PP 270-271.

[313] *Id.* PP 280-283.

144. The Presiding Judge also rejected, as inconsistent with Opinion Nos. 531 and 531-B, arguments by Mr. Hill that Dr. Avera's model was invalid because it considered historical data and because it did not consider long-term growth rates.[314] The Presiding Judge also rejected Mr. Hill's criticism of Dr. Avera's size-based adjustments to the risk premium, concluding that they "fail[ed] to grasp, much less address, the rationale underlying the size adjustment."[315] The Presiding Judge also elected not to rely on Mr. Hill's CAPM on the grounds that it was partly backward looking, in contrast to the CAPM relied upon by the Commission in Opinion No. 531, and also because it addressed stock price appreciation rather than earnings growth and failed to adjust for the companies' market capitalization, which, as noted, is required by the CAPM model.[316]

145. The Presiding Judge also rejected the Joint Consumer Advocates' critiques of Dr. Avera's methodology, which were based largely on the testimony of Mr. Solomon, concluding that they were inconsistent with the Commission's reliance on a CAPM model in Opinion Nos. 531 and 531-B. In particular, the Presiding Judge noted that Mr. Solomon's critiques would have excluded companies that the Commission in Opinion No. 531-B found appropriate to include in the CAPM model.[317]

146. Finally, the Presiding Judge rejected Mr. Keyton's critiques of Dr. Avera's CAPM. The Presiding Judge concluded that Mr. Keyton's arguments regarding the sustainability of the growth the rates and the measure of a risk-free return used by Dr. Avera were effectively rejected by the Commission in Opinion No. 531-B, substantially for the reasons stated above.

b. <u>Briefs on Exceptions</u>

147. Complainants and other parties contend that the Presiding Judge erred by accepting Dr. Avera's CAPM analysis despite evidence demonstrating that flaws in the analysis render the results unreliable.[318] Complainants explain that Mr. Gorman

[314] *Id.* PP 284-286.

[315] *Id.* P 290.

[316] *Id.* PP 294-297.

[317] *Id.* PP 298-303.

[318] Complainants Brief on Exceptions at 48-51; Joint Customer Intervenors Brief on Exceptions at 43-47; OMS Brief on Exceptions at 33-37; Trial Staff Brief on Exceptions at 42-44.

proposed certain adjustments to correct Dr. Avera's CAPM analysis, such as replacing the size premium adjustment with an industry premium adjustment.[319] Complainants explain that the Presiding Judge stated that "Mr. Gorman failed to demonstrate that [the Morningstar] analysis is inappropriate for utilities."[320] Complainants state that the Presiding Judge appears to have misunderstood Mr. Gorman's proposal, which argues that Morningstar recognized that there are differences in risk that are not captured by the beta attributable to the industry in which a company operates.[321]

148. Complainants state that the Presiding Judge misunderstands Opinion No. 531 and Morningstar's methodology. Complainants aver that the Opinion No. 531 proceeding did not include evidence involving the industry risk premium and Morningstar's broad variation of the CAPM model to reflect firm size and industry risk. Complainants argue that Morningstar does not limit its risk return criteria to only a size adjustment, and instead uses all available and applicable information to accurately adjust the CAPM to reflect investment risk.[322] Complainants state that the Presiding Judge erred by concluding that the buildup method is not a variation of CAPM, and assert that Morningstar undertakes multiple adjustments from the base CAPM to account for both a size adjustment and an industry risk premium.[323]

149. Trial Staff states that Dr. Avera's CAPM calculation arrives at the weighted average growth rates projected for all dividend-paying companies on the S&P 500 through the use of both IBES and Value Line. Trial Staff further states that the Presiding Judge found that in Opinion No. 531, "the Commission found a CAPM using a format substantially similar to that used by Dr. Avera in this case to be a useful guide in determining the placement of the Base ROE," and that "Dr. Avera's CAPM is credible and supports allowing the MISO TOs' to collect a Base ROE above the Midpoint."[324] Trial Staff asserts, however, that this finding is in error because Dr. Avera's CAPM

[319] Complainants Brief on Exceptions at 48 (citing Exh. JC-9 at 20-22 (stating that an industry premium adjustment for the electric utility industry would be negative)).

[320] *Id.* at 49 (citing Initial Decision, 153 FERC ¶ 63,027 at P 281).

[321] *Id.* (citing Exh. JC-9 at 20-21).

[322] *Id.* at 49-50 (citing Exh. JC-9 at 21-22).

[323] *Id.* at 49-50.

[324] Trial Staff Brief on Exceptions at 42 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 310-311).

calculation in the Opinion No. 531 proceeding used only IBES growth rate projections.[325] Trial Staff states that Dr. Avera's CAPM calculation in the instant proceeding is contrary to the Commission's stated preference, which the Presiding Judge acknowledges in his Initial Decision, to use IBES as the source for growth rates and to use only one source for growth rates in a given calculation.[326] Trial Staff asserts that Opinion No. 531 leaves no doubt that it is "inappropriate to use estimates from different sources for different proxy group companies."[327] Trial Staff asserts that Dr. Avera's use of both IBES and Value Line data contradicts the Presiding Judge's finding in the Initial Decision that use of IBES alone is appropriate for growth rate projections used in the Commission's DCF analysis in this proceeding.[328]

150. Trial Staff argues that the Presiding Judge incorrectly concluded that (1) the beta component of the CAPM risk-premium calculation "serves to mitigate any differences" between the divergent growth rates used in Dr. Avera's CAPM and DCF analyses, and (2) the beta component of the CAPM "serves the same purpose as the long-term growth rate component" of the DCF.[329] Trial Staff argues that beta measures risk (i.e., the variability of expected returns) and is a different concept than a sustainable growth rate, which measures a firm's long-term expansion. Trial Staff, therefore, asserts that it is not possible for beta to mitigate an unsustainable growth rate or serve the same purpose as the long-term growth rate.[330]

151. Joint Customer Intervenors state that Dr. Avera used a 9 percent market risk premium instead of the independently-published Morningstar market risk premium of 6.2 percent.[331] Joint Customer Intervenors assert that had Dr. Avera used Morningstar's

[325] *Id.* (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 110 ("The growth rate in the NETOs' CAPM analysis is based on IBES data, which the Commission has long relied upon as a reliable source of growth rate data")).

[326] *Id.* at 43 (citing Initial Decision, 153 FERC ¶ 63,027 at P 43).

[327] *Id.* at 44 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 90).

[328] *Id.* at 43-44.

[329] *Id.* at 44 n.84 (citing Initial Decision, 153 FERC ¶ 63,027 at P 305).

[330] *Id.* n.84.

[331] Joint Customer Intervenors Brief on Exceptions at 44 (citing Exh. MTO-1 at 97).

6.2 percent market risk premium, his midpoint unadjusted ROE would have been just 7.5 percent.[332]

152. Joint Customer Intervenors assert that Dr. Avera inappropriately adjusted the theoretical construct based on his contentions that "financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size" and that "empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn somewhat less than predicted."[333] According to Joint Customer Intervenors, Dr. Avera's adjustments increased the CAPM-derived midpoint ROE from 9.53 percent to 10.24 percent.[334]

153. Joint Customer Intervenors state that Mr. Solomon noted that the Commission has previously rejected the use of the CAPM methodology because its beta does not fully capture and differentiate risks of common stocks, and argued that CAPM results are thus unreliable and should not be used. Joint Customer Intervenors assert that the Presiding Judge did not address the merit of this argument.[335]

154. Joint Customer Intervenors note that the Presiding Judge found that Dr. Avera's "decision to include only . . . short-term growth components inevitably skews his zone of reasonableness upward."[336] Joint Customer Intervenors contend that this finding indicates that for a DCF study of non-utility companies to produce a reasonable result, a second-stage growth rate must also be included. Joint Customer Intervenors argue, however, that Dr. Avera failed to apply a second-stage growth rate, which the Commission found necessary in Opinion No. 531. Joint Customer Intervenors state that the Presiding Judge recognized that the Commission reasoned in Opinion No. 531-B that "[w]hile an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization."[337] Joint

[332] *Id.* (citing Exh. JCI-4 at 45:11-13).

[333] *Id.* at 44-45 (citing Exh. MTO-1 at 113).

[334] *Id.* at 45 (citing Exh. JCI-4 at 45:17-19; Exh. MTO-7 at 1).

[335] *Id.* at 44 (citing Exh. JCI-4 at 45:22-46:11).

[336] *Id.* at 45-46 (citing Initial Decision, 153 FERC ¶ 63,027 at P 328).

[337] *Id.* at 46 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 267 & 304; Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113).

Customer Intervenors argue, however, that Dr. Avera's CAPM analysis did not use a stock index; rather it used a fixed portfolio of approximately 400 stocks picked *ex ante*. Moreover, Joint Customer Intervenors assert that the Presiding Judge effectively conceded that each company in that portfolio will see its growth trend towards the long-term GDP growth rate and, therefore, the portfolio as a whole must likewise trend towards the long-term GDP growth rate. Joint Customer Intervenors explain that the beta component of CAPM is a measure of stock volatility, and disagree with the Presiding Judge's finding that the "beta component serves the same purpose of the long-term growth-rate . . . ."[338]

155. Joint Customer Intervenors state that Dr. Avera's approach relies on a DCF analysis of approximately 400 dividend-paying companies culled from the S&P 500. Joint Customer Intervenors contend that, if the Commission has concerns about the accuracy of the DCF methodology employing a proxy group of electric utilities, it makes even less sense to depend on an aggregation of dividend-paying companies in the S&P 500. According to Joint Customer Intervenors, dividends are less important and less reliable for S&P 500 companies when compared to electric utilities, which have been known as relatively low risk, income-producing investments.[339]

156. OMS states that Dr. Avera's CAPM study for the instant proceeding, which incorporates Value Line growth estimates, differs materially from his CAPM study cited in Opinion No. 531, which relied on growth rates taken from Yahoo! Finance's reporting of IBES estimates.[340] OMS asserts that Value Line growth estimates are substantially backward-looking, and notes that the Initial Decision found Value Line to be inferior in a separate passage.[341]

157. OMS argues that the Presiding Judge erred by treating beta as a substitute for second-stage growth. OMS states that beta is a measure of volatility, or systematic risk, of a security or a portfolio in comparison to the market as a whole.[342] OMS states that,

[338] Joint Customer Intervenors Brief on Exceptions at 46-47 (citing Initial Decision, 153 FERC ¶ 63,027 at P 305).

[339] *Id.* at 45.

[340] OMS Brief on Exceptions at 37 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 110; Exh. MTO-30 at 1, note (b)).

[341] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at PP 48-49).

[342] OMS Brief on Exceptions at 36 (citing Andrew J. Cueter, *Using Beta* (Oct. 2012),

while the beta for utility stock consistently averages well below 1.0, exceptions in which a utility stock's beta exceeds 1.0 and thus increases that proxy's CAPM result, are Common.[343] OMS states that the second-stage growth rate, on the other hand, is necessary to incorporate the effect of changes in the general economy (as represented by GDP growth) in forecasting the long-term growth of an individual company or group of companies. According to OMS, the second-stage growth rate is part of getting to a reliable number for the expected long-term return on a fully diversified equity portfolio – an essential ingredient for a CAPM study to produce any sort of useful result. OMS argues that to equate beta and the second-stage growth rate because in this particular instance "[e]ach serves to lower the top of the zone of reasonableness" is not well-reasoned.[344]

158. OMS states that the growth component of the portfolio return calculation used by Dr. Avera weighted short-term growth rates forecasted by IBES and Value Line at 100 percent, thereby assuming that the growth rates over the next five years will continue forever. OMS asserts that this premise is implausible and flies in the face of the Commission's determination in Opinion No. 531 to use a weighted average of short and long-term growth rates in its two-step DCF analysis. OMS states that the failure to incorporate a blended growth rate is the precise reason the Presiding Judge rejected Dr. Avera's DCF study of non-utility companies, wherein the Presiding Judge observed that "[Dr. Avera's] decision to include only dividend yields and short-term growth components inevitably skews his zone of reasonableness upward."[345] OMS argues that it is arbitrary and capricious for the Initial Decision to reject one of Dr. Avera's studies for its failure to incorporate long-term growth rates, while adopting another that suffers from precisely the same flaw.[346]

http://www.valueline.com/Tools/Educational_Articles/Stocks/Using_Beta.aspx#.Vp5VhZorJaQ).

[343] *Id.* at 36 (citing Richard A. Michelfelder and Panayiotis Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings* (Nov. 2013), at 60, 66 (showing in Figure 1 that the top decile of utility betas exceeded 1.0 for some years and the highest utility beta exceeded 1.0 in most years)).

[344] *Id.* at 36-37 (citing Initial Decision, 153 FERC ¶ 63,027 at P 305).

[345] OMS Brief on Exceptions at 34 (citing Initial Decision, 153 FERC ¶ 63,027 at P 328).

[346] *Id.*

159. OMS acknowledges that Opinion No. 531-B rejected arguments that the Commission erred by adopting a CAPM formulation that failed to include a second-stage growth rate. OMS states that, consistent with Opinion No. 531-B, the Presiding Judge held that "[w]hile an individual company cannot be expected to sustain high short-term growth rates into perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization."[347] OMS contends, however, that such reasoning makes no more sense in the Initial Decision than it did before.[348]

160. OMS states that, in rejecting Dr. Avera's non-utility DCF analysis for its failure to incorporate a second-stage growth factor, the Presiding Judge implicitly recognized that, over time, each individual company in Dr. Avera's portfolio will see its growth rate trend downward toward the long-term GDP growth rate. OMS asserts that, if each company in the portfolio will see its growth rate trend toward the GDP growth rate, so also will the portfolio as a whole. OMS, therefore, contends that the CAPM calculation is illogical and indefensible.[349]

161. OMS asserts that the rationale, as stated in Opinion No. 531 and adopted by the Initial Decision, simply does not apply. OMS explains that the portfolio Dr. Avera used in his CAPM study was not the S&P 500 itself, with a constantly updated cast of high-capitalization companies; rather, it was a fixed portfolio of 400 stocks. OMS stresses that the 400 stock portfolio will not be "regularly updated" to include only companies with high market capitalizations.[350]

c. <u>Briefs Opposing Exceptions</u>

162. MISO TOs contend that the Presiding Judge correctly accepted Dr. Avera's CAPM analysis and correctly found that this analysis supports establishing a base ROE above the midpoint. MISO TOs argue that the arguments raised by Complainants, Joint Customer Intervenors, and OMS were all considered and rejected in Opinion No. 531-B and thus were appropriately rejected, implicitly or explicitly, in the Initial Decision.[351]

[347] *Id.* at 35 (citing Initial Decision, 153 FERC ¶ 63,027 at P 304 (quoting Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113)).

[348] *Id.*

[349] *Id.* at 35-36.

[350] *Id.* at 35.

[351] MISO TOs Brief Opposing Exceptions at 28.

MISO TOs state that Opinion No. 531-B analyzed and found meritless arguments critical of Dr. Avera's CAPM analysis because Dr. Avera (1) performed a DCF study on the S&P 500, (2) employed a size adjustment, (3) did not employ a long-term growth component, and (4) relied on betas based on historical data as a risk measure.[352]

163. MISO TOs argue that Complainants' advocacy for Mr. Gorman's CAPM analysis does not withstand scrutiny because Mr. Gorman's CAPM market premium is not based on a DCF analysis or any other forward-looking approach. MISO TOs assert that Mr. Gorman's use of Morningstar's buildup method is distinct from, and not used in, the CAPM methodology.[353] Furthermore, MISO TOs state that the publication on which Mr. Gorman relied only applies an industry-based adjustment factor to the buildup method of estimating risk premiums and not to the well-established CAPM that Dr. Avera employed and that the Commission accepted in Opinion No. 531.[354]

164. With regard to Trial Staff's objections to Dr. Avera's use of both IBES and Value Line growth rate estimates in his CAPM analysis, MISO TOs assert that the Presiding Judge cited Dr. Avera's CAPM analysis for the limited purpose of informing placement of the base ROE within the zone of reasonableness. MISO TOs argue that the Presiding Judge did not explicitly find that only IBES growth rate data are acceptable for purposes of applying the DCF model.[355]

d. <u>Commission Determination</u>

165. We affirm the Presiding Judge's findings that the MISO TOs' witness, Dr. Avera, properly performed his CAPM analysis and that the CAPM methodology supports the Commission's determination that the mechanical application of the DCF methodology results in an ROE that is inconsistent with *Hope* and *Bluefield*.

166. With regard to MISO TOs' size premium adjustment, the Commission stated in Opinion No. 531-B that the use of such an adjustment was "a generally accepted approach to CAPM analyses."[356] The Commission explained that "[t]he purpose of the

[352] *Id.* at 28-29.

[353] *Id.* at 29 (citing Complainants Brief on Exceptions at 48-51).

[354] *Id.* at 29-30 (citing Initial Decision, 153 FERC ¶ 63,027 at P 271).

[355] *Id.* at 31.

[356] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117.

. . . size adjustment is to render the CAPM analysis useful in estimating the cost of equity for companies that are smaller than the companies that were used to determine the market risk premium in the CAPM analysis."[357] Moreover, Mr. Gorman acknowledged that Morningstar proposes to add a size premium adjustment to the CAPM return because research suggests that systematic risk for small companies may not be completely reflected in the company's beta.[358] While Mr. Gorman asserted that Morningstar uses portfolios with a beta greater than one and the national proxy group has a beta less than one,[359] he does not explain how or why that fact would produce overstated results that would bar MISO TOs from making a size premium adjustment. Indeed, nothing in the record supports the notion that there is a correlation between beta and the size premium adjustment used by MISO TOs. As such, we are not persuaded by Complainants' and Joint Customer Intervenors' assertions that the size premium adjustment that is used by Morningstar cannot be used by MISO TOs.[360] For these reasons, we reject Complainants' argument that the size premium adjustment is flawed.

167. With regard to Complainants' proposed industry premium adjustment, the primary issue is whether it should be included in CAPM analyses or it should be limited to Morningstar's buildup method of determining the cost of equity. Complainants assert that the buildup method is a variation of CAPM. However, a thorough examination of Morningstar's buildup method reveals that the underlying formula differs from the generally accepted CAPM formula.[361] Indeed, the buildup method formula used by Morningstar does not consider beta, a fundamental input used in CAPM analyses. Therefore, as an initial matter, we affirm the Presiding Judge's conclusion that Mr. Gorman has failed to demonstrate that Morningstar's use of an industry premium adjustment in its buildup method has any relevance to CAPM analyses.[362]

[357] *Id.* P 117.

[358] Exh. JC-9 (corrected) at 20-21.

[359] *Id.* at 20.

[360] *See* Initial Decision, 153 FERC ¶ 63,027 at P 281.

[361] Exh. MTO-59 at 6 (the buildup method formula used by Morningstar is as follows: Cost of Equity Estimate = Riskless Rate + Equity Risk Premium + Industry Risk Premium + Size Premium). For comparison, the CAPM formula is as follows: Required return = Risk-free Rate + Beta x (Expected Return – Risk-free Rate). *See* Initial Decision, 153 FERC ¶ 63,027 at P 259 (citing Exh. JC-9 at 41:2-10).

[362] *See* Initial Decision, 153 FERC ¶ 63,027 at P 271.

168. Nevertheless, Complainants assert that an industry premium adjustment to the CAPM analysis is necessary. Therefore, they bear the burden of demonstrating that the inclusion of this adjustment is appropriate. Morningstar explains that the industry premium "measures how risky the industry is in relation to the market as a whole, regardless of size."[363] As discussed above, beta, like the industry risk premium, is a measure of risk relative to the market. We note that every company in the national proxy group has a beta of less than one.[364] From that, we conclude that the betas already reflect the fact that the proxy group companies are low risk relative to the market generally. Accordingly, because the betas already reflect the relative risk of the industry, we conclude that it would be inappropriate to add an industry risk premium to the CAPM analyses.

169. Trial Staff argues against the use of Value Line growth rates in MISO TOs' CAPM analysis. While the Commission has found that Value Line's growth rate estimates are not acceptable as the short-term consensus growth rate input for the two-step DCF model, the Commission has nevertheless found that Value Line is a valid source of general financial data. In the instant CAPM analysis, the Value Line data is used in conjunction with IBES data and both are averaged over a 400-company data set. This use of growth rate data is fundamentally different from how growth rate data is used in our DCF model, because it is intended to provide a less precise cost of equity estimate than the DCF model. Although we require more precision from our DCF model—as the primary financial model that we use, and have used for decades, to determine public utility ROEs—that same degree of precision is less essential in the CAPM analysis because that analysis is but one of multiple pieces of evidence corroborating the results of our DCF analysis. Furthermore, no party demonstrated that the Value Line growth rate estimates for dividend-paying S&P 500 companies are unreasonably high or low, or that reliance on IBES growth rate estimates alone would produce a materially different CAPM result using data from the study period. For these reasons, we conclude that MISO TOs' use of both IBES and Value Line growth rate estimates in their CAPM analysis is reasonable for purposes of corroborating the results of the DCF analysis.

170. While we agree with Trial Staff, Joint Customer Intervenors, and OMS that beta does not serve the same function as the long-term growth rate component of the DCF,[365] we note that a long-term growth rate component is not required in the DCF study used to develop the market risk premium for MISO TOs' CAPM analysis. As the Commission

[363] Exh. MTO-59 at 4.

[364] *See* Exh. MTO-30 at 1-2.

[365] Trial Staff Brief on Exceptions at 44 n.84.

explained in Opinion No. 531-B, the rationale for requiring a two-step DCF methodology that incorporates a long-term growth rate input when conducting a DCF study on a specific group of public utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. While it is often unrealistic and unsustainable for high short-term growth rates for an individual company to continue in perpetuity, the S&P 500 is regularly updated to only include companies with high market capitalization.[366] Joint Customer Intervenors and OMS argue that this rationale does not apply because MISO TOs did not rely on the S&P 500 index, but instead studied approximately 400 dividend-paying companies culled from the S&P 500. We disagree. MISO TOs did not arbitrarily select companies; they selected every dividend-paying stock included in the S&P 500, a group that is regularly updated.[367] As such, it is indisputable that each company selected by MISO TOs had a high market capitalization at that time. Therefore, consistent with Opinion No. 531-B, we find that the DCF study of the approximately 400 dividend-paying stocks selected by MISO TOs need not include a two-step DCF methodology that incorporates a long-term growth rate input.

171. Joint Customer Intervenors assert that MISO TOs' CAPM analysis should have used the Morningstar market risk premium of 6.2 percent, which was based on the arithmetic average difference between stocks and Treasury bills from 1926 to 2013.[368] However, the Morningstar market risk premium relies on historical data and, therefore, any CAPM analyses using the Morningstar market risk premium would be backward-looking.[369] Joint Customer Intervenors, therefore, request that the Commission accept a backward-looking CAPM analysis despite the fact that the Commission has historically accepted forward-looking CAPM analyses and rejected backward-looking CAPM analyses.[370] Accordingly, we reject Joint Customer Intervenors' requested use of the

[366] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113.

[367] *See* Initial Decision, 153 FERC ¶ 63,027 at P 260. Non-dividend paying S&P companies must be excluded from the DCF analysis, because a DCF analysis cannot be performed for a non-dividend paying company.

[368] Exh. JCA-1 at 21:21-27.

[369] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 108 (citing Roger A. Morin, *New Regulatory Finance* 155-156 (Public Utilities Reports, Inc. 2006)).

[370] Initial Decision, 153 FERC ¶ 63,027 at PP 279-280 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147 n.292).

Morningstar market risk premium because doing so would result in a CAPM analysis that is not representative of the capital market conditions present during this proceeding.[371]

172. For the reasons stated above, we affirm the Presiding Judge's acceptance of the CAPM analysis to be used as corroborative evidence, in determining whether the midpoint of the zone of reasonableness produced by the Commission's DCF analysis provides a return that satisfies the requirements of *Hope* and *Bluefield*.[372]

3. <u>Risk Premium</u>

173. The risk premium methodology, in which interest rates are a direct input, is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[373] As the Commission found in Opinion No. 531, investors' required risk premiums expand with low interest rates and shrink at higher interest rates. The link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the interest rate environment.

174. Multiple approaches have been advanced to determine the equity risk premium for a utility.[374] For example, a risk premium can be developed directly, by conducting a risk premium analysis for the company at issue, or indirectly by conducting a risk premium analysis for the market as a whole and then adjusting that result to reflect the risk of the company at issue.[375] Another approach for the utility context is to "examin[e] the risk premiums implied in the returns on equity allowed by regulatory commissions for utilities

[371] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 118 (finding that a CAPM study is reliable and sufficiently representative of capital market conditions if it is prospective and does not pre-date the Great Recession).

[372] *See* Initial Decision, 153 FERC ¶ 63,027 at P 311.

[373] Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (citing Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006).

[374] *See generally* Roger A. Morin, *New Regulatory Finance* 107-130 (Public Utilities Reports, Inc. 2006).

[375] *Id.* at 110.

over some past period relative to the contemporaneous level of the long-term U.S. Treasury bond yield."[376]

175. MISO TOs' witness, Dr. Avera, followed a variation of the latter approach, developing a risk premium study by analyzing the ROEs allowed by this Commission for the period from 2006 through 2014, relative to the contemporaneous level of the yield of BBB-rated bonds, to calculate equity risk premiums for each year during that period.[377] Dr. Avera then averaged these annual risk premiums to determine an average risk premium for the entire 2006-2014 period of 4.77 percent.[378]

176. Dr. Avera next adjusted this risk premium to reflect the tendency of risk premiums to rise as interest rates fall. Dr. Avera stated that the average yield of bonds rated BBB by S&P during the period 2006 to 2014 was 5.90 percent. However, the average yield of bonds rated Baa by Moody's during the January-June 2015 period used for the DCF analysis in this case was 4.55 percent, a difference of 1.35 percent.[379] This difference reflects the extent to which current bond yields have fallen below the 2006-2014 average. Based on MISO TOs' regression analysis of the annual equity risk premiums he calculated for each of the nine years from 2006 to 2014, the risk premium during that period increased by approximately 77.07 basis points for each percentage drop of the BBB-rated bond yields.[380] By applying the 77.07 basis point coefficient to the 1.35 percent reduction in bond yields, Dr. Avera calculated a risk premium adjustment of 1.04 percent, which Dr. Avera added to the 4.77 percent average risk premium for the 2006-2014 period to calculate an adjusted risk premium for the six-month DCF study period of 5.81 percent. Finally, Dr. Avera added the 5.81 percent adjusted risk premium to the 4.55 percent Baa-rated bond yield during the six-month DCF study period to calculate a risk premium-based cost of equity of 10.36 percent.[381]

[376] *Id.* at 123.

[377] Exh. MTO-29 at 3; *see also* Exh. MTO-29 at 3.

[378] Exh. MTO-1 at 101:18-19.

[379] Exh. MTO-29 at 1. MISO TOs treated BBB and Baa rate bonds as having equivalent yields.

[380] *See* Exh. MTO-29 at 6.

[381] Exh. MTO-29 at 1; *see also* Initial Decision, 153 FERC ¶ 63,027 at PP 233-235.

a. Initial Decision

177. The Presiding Judge determined that the risk premium model offered by Dr. Avera was valid and supports awarding MISO TOs a base ROE above the midpoint of the zone of reasonableness. The Presiding Judge noted that the Commission in Opinion No. 531 accepted Dr. Avera's risk-premium analysis and that he had supported his contention that the risk premium rises as the interest rates fall with numerous authorities.[382] The Presiding Judge rejected Mr. Gorman's risk premium model, observing that it was "appreciably different" from the analysis used by the Commission in Opinion No. 531 and that Mr. Gorman did not justify these differences. The Presiding Judge also noted that Mr. Gorman did not address the inverse relationship between bond yields and the risk premium that the Commission "endorsed" in Opinion No. 531.

178. The Presiding Judge also rejected the criticisms of the risk premium model advanced by various witnesses, noting that, although they might be a reason not to rely on the risk premium model in lieu of a DCF analysis, they did not demonstrate that it shouldn't be used as a check on the DCF model.[383] Relying on the Commission's determinations in Opinion No. 531-B, the Presiding Judge also rejected arguments that risk premium model suffered from regulatory lag—the idea that bond yields were not contemporaneous with the various study periods—and that the risk premium analysis was flawed because many of the included ROEs were set by settlement. Finally, the Presiding Judge rejected critiques of Dr. Avera's sample size and statistical methodology, noting that they were equivalent or superior to those that the Commission accepted and relied upon in Opinion No. 531.

b. Briefs on Exceptions

179. Complainants argue that Dr. Avera's risk premium analysis, which the Initial Decision adopted, is inconsistent with the finding of anomalous market conditions. Complainants contend that, because the Initial Decision found that current market conditions are unsustainable, it is inappropriate to accept Dr. Avera's risk premium model, which Complainants assert is based on an unsustainable relationship between equity returns and bond yields during a period of unsustainable capital market conditions.[384]

[382] Initial Decision, 153 FERC ¶ 63,027 at P 260.

[383] *Id.* P 241.

[384] Complainants Brief on Exceptions at 37-39.

180. Complainants assert that Dr. Avera's risk premium analysis is flawed because the regression study is based on only nine observations (the annual equity risk premiums for each year from 2006 to 2014). Complainants note that, rather than looking at the individual company-authorized ROEs, Dr. Avera made simplifying assumptions that likely increased the results.[385] Complainants also allege that, rather than relying on independent market participants' projected Baa-rated bond yield, Dr. Avera developed his own projected utility bond yield.[386] Complainants further assert that Dr. Avera's adjustments to the data produce excessive ROEs based on today's current capital market environment.[387] Complainants also cite to arguments from Mr. Solomon and Mr. Hill regarding flaws in the risk premium analysis.[388]

181. Complainants state that Dr. Avera's risk premium analysis should be disregarded and that Mr. Gorman's risk premium analysis should be considered.[389] According to Complainants, unlike Dr. Avera's risk premium analysis, Mr. Gorman's risk premium analysis is based on two estimates of equity return over the period of 1986 to 2015 to account for variations of the risk premium based on market conditions and investor risk perceptions.[390] Complainants explain that Mr. Gorman's risk premium analysis using U.S. Treasury bonds resulted in a range of 8.25 percent to 10.57 percent, his risk premium analysis using Baa-rated bonds resulted in a range of 7.53 percent to 10.13 percent, and the two analyses together resulted in a range of 7.53 percent to 10.57 percent with a midpoint of 9.05 percent.[391]

182. Complainants state that the current A-rated utility-bond yield to U.S. Treasury bond yield spread is approximately 116 basis points, while the 36-year average A-rated

[385] *Id.* at 45-46 (citing Exh. JC-9 at 27). Mr. Gorman seems to have argued that Dr. Avera erred by relying on the average authorized returns for each year, thereby weighing each of the eight authorized returns from 2013 less than each of the five authorized returns from 2014.

[386] *Id.* at 46 (citing Exh. JC-9 at 28).

[387] *Id.* at 46 (citing Exh. JC-9 at 28-29).

[388] *Id.* at 46-47 (citing Exh. JCI-4 at 41, Exh. JCA-11 at 36-42).

[389] *Id.* at 47.

[390] *Id.* at 39-40 (citing Exh. JC-9 at 47).

[391] *Id.* at 42-43 (citing Exh. JC-22 at 17).

utility-bond yield spread is 152 basis points. Complainants further state that the current Baa-rated utility-bond yield to U.S. Treasury bond yield spread is approximately equal to the 36-year average utility-bond yield spread. According to Complainants, the utility-bond yield spreads are evidence that the market considers electric utilities to be relatively low-risk investments and that utilities continue to have strong access to capital markets.[392]

183. Joint Customer Intervenors contend that several witnesses demonstrated flaws in Dr. Avera's risk premium analysis. Joint Customer Intervenors assert that the Initial Decision improperly rejected the identification of flaws in Dr. Avera's regression analysis on the basis that the Commission accepted the methodology in Opinion No. 531. Joint Customer Intervenors argue, however, that MISO TOs broadened the limited purpose for which the alternative analyses were used in Opinion No. 531 and that the flaws identified in the instant proceeding were not considered in Opinion No. 531.[393]

184. Joint Customer Intervenors argue that Dr. Avera's risk premium analysis was flawed because it relied completely on historical data, inconsistent with the Commission's long-established policy that the ROE methodology must be forward-looking.[394] Joint Customer Intervenors contend that the use of a historical risk premium analysis in conjunction with a forward-looking DCF analysis amounts to an unreliable mismatch.[395]

185. Joint Customer Intervenors contend that the Initial Decision dismissed their witness Mr. Solomon's arguments without addressing them.[396] First, Joint Customer Intervenors assert that Dr. Avera's risk premium analysis lacked a direct equity market input, thereby producing an unreliable and inflated estimate of the current cost of common equity capital. Second, Joint Customer Intervenors also assert that Dr. Avera's risk premium analysis' use of interest rates and risk premiums as the only inputs in its

[392] *Id.* at 42.

[393] Joint Customer Intervenors Brief on Exceptions at 39-43.

[394] *Id.* at 40 (citing Exh. JCI-4 at 41:15-16; *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 (2000)).

[395] *Id.*

[396] *Id.* at 40-42 (citing Initial Decision, 153 FERC ¶ 63,027 at P 255; *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998)).

regression analysis failed to consider other factors that influence risk premiums and thus cannot account for historical volatility in risk premiums.[397]

186. According to Joint Customer Intervenors, Mr. Solomon demonstrated that more recent data indicates that Dr. Avera's analysis was upwardly and improperly biased. Joint Customer Intervenors state that Dr. Avera's risk premium analysis calculated a 5.62 percent risk premium for the DCF study period during the first half of 2015, which Joint Customer Intervenors point out is 27 basis points above the 5.35 percent risk premium Dr. Avera observed for 2014.[398]

187. Joint Customer Intervenors also state that Dr. Avera's risk premium analysis calculated that, for every 1 percent drop in utility bond yields, the cost of equity capital goes down by just under 23 basis points. Joint Customer Intervenors note, however, that Dr. Avera concluded in a separate state commission-based risk premium analysis that ROEs declined over 57 basis points for every 1 percent reduction in the average utility bond yield. Joint Customer Intervenors argue that the disparity between the two analyses further supports placing no reliance on the results of such historical analyses.[399]

188. OMS asserts that Dr. Avera's risk premium study is fatally flawed by the inclusion of at least one data point that is demonstrably invalid and results in a grossly excessive risk premium. OMS states that one of the Base ROE decisions that Dr. Avera included in his data set can in no way be considered a cost of equity determination and, therefore, had no place in the data set of historic risk premiums.[400] OMS states that *ITC Holdings* was merely a docketing order insofar as ROE is concerned; it established that litigation of a just and reasonable ROE for the Entergy Operating Companies' transmission assets would be determined prospectively in the instant proceeding, rather than in the Entergy transmission rate docket. OMS argues that, by treating *ITC Holdings* the same as other orders where the Commission actually calculated a just and reasonable return for a company, Dr. Avera grossly inflated the historical risk premium.[401]

[397] *Id.* at 41 (citing Exh. JCI-4 at 51:17-20, 42:1-15).

[398] *Id.* at 41-42 (citing Exh. MTO-6 at 3).

[399] *Id.* at 43 (citing Exh. MTO-10).

[400] OMS Brief on Exceptions at 31 (citing *ITC Holdings Corp.*, 143 FERC | ¶ 61,257 (2013), *order on reh'g*, 146 FERC ¶ 61,111, at P 25 (2014) (*ITC Holdings*)).

[401] *Id.*

189. OMS states that it is a straightforward matter to correct the errors committed by Dr. Avera. OMS states that the Commission may take administrative notice of its past decisions and those decisions' underlying bases to the extent necessary to consider OMS' corrected version of Exhibit No. MTO-29.[402] OMS states that, by limiting the data points to actual base ROE determinations, its corrected version of Exhibit No. MTO-29 produces a value significantly lower than 10.32 percent.[403]

c. Briefs Opposing Exceptions

190. MISO TOs argue that the Presiding Judge correctly accepted Dr. Avera's risk premium analysis, and that his analysis simply serves as a check on the midpoint of the DCF range, and not the cost of capital model used to set the authorized ROE. MISO TOs assert that the Commission has previously accepted Dr. Avera's approach for its limited purpose.[404] MISO TOs state that the Presiding Judge properly concluded that Mr. Gorman's alternate risk premium analysis was "unreliable and produced cost of equity estimates that were unrepresentatively low."[405] MISO TOs disagree with OMS' characterization of the Commission's decision in *ITC Holdings* as "merely a docketing order insofar as ROE is concerned."[406] MISO TOs assert that the Commission found the current 12.38 percent ROE to be just and reasonable for Entergy as a MISO transmission owner, and rejected arguments for a different ROE.[407]

[402] *Id.* at Attachment 1 (removing or revising various data points from the list compiled by MISO TOs).

[403] OMS Brief on Exceptions at 32-33. OMS proposes a risk premium cost of equity of 9.94 percent. *Id.*, Attachment 1.

[404] MISO TOs Brief Opposing Exceptions at 24 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 97-101).

[405] *Id.* at 26.

[406] *Id.* (citing OMS Brief on Exceptions at 31); *see ITC Holdings*, 146 FERC ¶ 61,111.

[407] MISO TOs Brief Opposing Exceptions at 27 (citing *ITC Holdings*, 146 FERC ¶ 61,111 at P 60).

d. Commission Determination

191. We affirm the Presiding Judge's findings that the MISO TOs' risk premium study is valid and supports awarding the MISO TOs a base ROE above the midpoint. We disagree with Complainants' assertion that risk premium analyses cannot be relied upon during a period of anomalous capital market conditions. The Commission has already considered this question. In Opinion No. 531, the Commission stated that alternative methodologies serve as additional evidence to gain insight into the potential impacts of unusual capital market conditions on the appropriateness of using the resulting midpoint. The Commission found the risk premium analysis to be informative, and used it and other alternative methodologies to inform the placement of the just and reasonable ROE within the zone of reasonableness established by the DCF methodology.[408] Consistent with this precedent, we find that, as a general matter, it is appropriate to rely on risk premium analyses as corroborative evidence during periods of anomalous capital market conditions.

192. With regard to assertions regarding the number of observations in MISO TOs' regression analysis, we find that the nine-year period is sufficiently large to inform a risk premium study. Since the issuance of Order No. 679, when the Commission commenced setting "up-front ROEs," a substantial amount of ROE data points became available. Moreover, MISO TOs' regression analysis covers a period both before and after the financial crisis, and considers approximately 80 Commission-accepted ROE data points over the nine-year period.[409] Neither Complainants nor Complainant-aligned parties provided additional Commission-accepted ROE data points for the years preceding 2006, so we have no evidence that doing so would substantially impact MISO TOs' regression analysis.[410]

193. While Complainants suggest that each ROE data point should be its own observation in the regression analysis, we are not persuaded that doing so would be superior to MISO TOs' regression analysis, based on the nine annual equity premiums

[408] Opinion No. 531, 147 FERC ¶ 61,234 at PP 145-146.

[409] Exh. MTO-29 at 4-5.

[410] Complainants' risk premium analysis considers state commission-accepted ROEs for the period from 1986 through March 2015. *See* Exh. JC-19. The Commission rejected the results of a similar risk premium study due to the risk differential between state-regulated distribution and Commission-regulated interstate transmission. Opinion No. 531-B, 150 FERC ¶ 61,165 at P 99. Accordingly, we reject Complainants' risk premium analysis.

during the years 2006-2014. Complainants' proposal would require each ROE data point to be matched with the bond yield that existed on the date of the Commission's acceptance of that data point.[411] However, Complainants have not demonstrated why the bond yield on that specific date is more representative of the interest rate environment than the average annual bond yields used by MISO TOs. Indeed, there is no fixed relationship – and there is a lag – between dates of the relevant study period and the date on which the Commission adopts an ROE, with the variation depending on the facts of the case. Therefore, it seems that assigning the bond yield on one specific date to each data point would add an unnecessary amount of volatility to the regression analysis. Furthermore, the Commission already held in Opinion No. 531-B that assigning approximate dates to the cost of equity determinations is often unavoidable and does not undermine the relevance of risk premium analyses. For these reasons, we find that the methodology used by MISO TOs in their regression analysis is appropriate.

194. We also reject Complainants' argument that MISO TOs should have relied on independent market participants' projected Baa-rated bond yield. The Presiding Judge held that projected yields used in risk premium analyses are speculative and less reliable than historical yields, and rejected Dr. Avera's use of projected Baa-rated bond yields. As an initial matter, we agree with the Presiding Judge and, for that reason, reject Complainants' argument.

195. With regard to Joint Customer Intervenors' argument that MISO TOs' risk premium analysis was flawed because it relied completely on historical data, we note that the risk premium analysis accepted in Opinion No. 531-B was based on "empirical observations and regression analysis of bond yields and Commission-allowed ROEs"—i.e., forms of historical data.[412] In any event, because the risk premium analysis uses regulated ROEs, it would be inappropriate to attempt to project what such ROEs would be. Moreover, despite Joint Customer Intervenors' assertion that MISO TOs' risk premium analysis is inconsistent with the Commission's policy that the ROE methodology must be forward-looking, we are not relying on the risk premium analysis to set the ROE itself. Instead, we find that MISO TOs' risk premium analysis is sufficiently reliable to corroborate our decision to place MISO TOs' base ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.[413]

[411] Exh. JC-9 (corrected) at 27.

[412] Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 97-101.

[413] *Id.* P 98.

196. We disagree with Joint Customer Intervenors' assertion that MISO TOs' risk premium analysis is flawed because it lacks a direct market input and fails to consider other factors that influence risk premiums. MISO TOs' risk premium analysis is similar to the risk premium analysis accepted in Opinion No. 531-B. Therefore, in order to demonstrate that MISO TOs' risk premium analysis is flawed, Joint Customer Intervenors must either raise and reasonably support new arguments that were not considered in the Opinion No. 531 proceeding, or differentiate between the two risk premium analyses. Joint Customer Intervenors fail to do either. For example, Joint Customer Intervenors generically claim that MISO TOs' risk premium analysis is lacking, but do not propose specific factors that should be considered. As a result, we have no basis to conclude that any further considerations are necessary. Moreover, while Joint Customer Intervenors claim that MISO TOs' risk premium analysis cannot account for historical volatility, they fail to demonstrate that this purported historical volatility would result in materially different risk premium results.[414]

197. Joint Customer Intervenors disagree with MISO TOs' regression analysis and its result: for every percentage drop of the BBB-rated bond yields, the risk premium increased approximately 77.07 basis points and, therefore, the cost of equity capital would decrease by approximately 22.93 basis points. We note, however, that the 77.07 basis point coefficient proposed by MISO TOs is substantially less than the 93 basis point coefficient in the analysis that the Commission relied upon in Opinion No. 531-B.[415] Furthermore, despite Joint Customer Intervenors' arguments to the contrary, the Commission held in Opinion No. 531-B that it was not persuaded by arguments that the results of a Commission-based risk premium analysis "are invalid simply because they differ from the inferred rate relationship reflected in historical state commission-approved ROEs, particularly where anomalous capital market conditions exist that may impact the inferred relationship between risk premiums and interest rates."[416]

198. As for OMS' argument that MISO TOs included data points in their risk premium analysis that should not have been considered, the Commission dismissed similar arguments in Opinion No. 531-B by concluding that "whether the regulatory decision involved a settlement agreement or the application of a cost of equity that was calculated in the past, e.g., the 12.38 percent ROE established for the MISO region, does not affect

[414] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98.

[415] *Id.* P 99.

[416] *Id.* P 99.

the reliability of a risk premium analysis."[417] Accordingly, we reject OMS' arguments that *ITC Holdings* and other data points should be removed from MISO TOs' risk premium analysis.

199. OMS also proposes revisions to the dates of several data points included in MISO TOs' risk premium analysis. Although we agree with OMS that any necessary corrections should be made, OMS has not demonstrated that its proposed date corrections would materially affect the results of MISO TOs' risk premium analysis.[418] Therefore, we find that these discrepancies do not undermine the usefulness of MISO TOs' risk premium analysis as corroborative evidence.

200. For the reasons stated above, we find that MISO TOs' risk premium analysis is sufficiently reliable to corroborate the results of the DCF analysis in this proceeding. We, therefore, affirm the Presiding Judge's acceptance of the risk premium analysis to be used as corroborative evidence, in determining whether the midpoint of the zone of reasonableness produced by the Commission's DCF analysis provides a return that satisfies the requirements of *Hope* and *Bluefield*.[419]

4. <u>Expected Earnings</u>

201. A comparable earnings analysis is a method of calculating the earnings an investor expects to receive on the book value of a particular stock. The analysis can be either backward looking using the company's historical earnings on book value, as reflected on the company's accounting statements, or forward-looking using estimates of earnings on book value, as reflected in analysts' earnings forecasts for the company.[420] The latter approach is often referred to as an "expected earnings analysis" and is the approach that MISO TOs used in this proceeding. As the Commission explained in Opinion No. 531-B, "returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk" and, as

[417] *Id.* P 98. In *ITC Holdings*, the Commission approved the Entergy Operating Companies' use of the 12.38 percent ROE established for the MISO region. *ITC Holdings*, 146 FERC ¶ 61,111 at P 25.

[418] While OMS calculated a risk premium cost of equity of 9.94 percent, OMS' analysis revised dates for several data points *and* removed approximately 15 data points from MISO TOs' risk premium analysis. OMS Brief on Exceptions, Attachment 1.

[419] *See* Initial Decision, 153 FERC ¶ 63,027 at P 258.

[420] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 125.

a result, an expected earnings analysis can be useful for corroborating whether the results produced by the DCF model may have been skewed by the anomalous capital market conditions reflected in the record.[421]

202. MISO TOs' forward-looking expected earnings analysis uses the same proxy group used in their two-step DCF analysis. MISO TOs' witness, Dr. Avera, started with the return on book equity that Value Line forecasts for each proxy company for the period 2017 to 2019.[422] He then multiplied each of those returns by an adjustment factor to determine each utility's average return, rather than its year-end return. After the elimination of one outlier result,[423] Dr. Avera's analysis produced an adjusted ROE range of 7.61 percent to 16.37 percent, with a midpoint value of 11.99 percent. As with the other alternative methodologies accepted herein, this midpoint value exceeds the 9.29 percent midpoint value of the Commission's two-step DCF analysis.[424]

a. Initial Decision

203. The Presiding Judge declined to rely on Dr. Avera's forward-looking expected earnings analysis. While acknowledging that the Commission in Opinion No. 531 relied upon an expected earnings analysis "identical in all material respects" to Dr. Avera's, the Presiding Judge observed that the Commission was not aware of a critique by Dr. Morin—on whose authority the Commission relied in accepting the expected earnings analysis in Opinion No. 531—that such analysis should be based on a sample of unregulated, rather than regulated, companies. Because Dr. Avera's analysis relied on the regulated companies in the proxy group, and because of "Dr. Avera's inability to address [Dr. Morin's] rejection" of the use of regulated companies in an expected earnings analysis, the Presiding Judge elected not to rely on Dr. Avera's analysis.[425]

[421] *Id.* PP 128-129.

[422] Ex. MTO-31.

[423] Dr. Avera eliminated Dominion Resources' adjusted return on common equity of 18.38 percent.

[424] *See* Initial Decision, 153 FERC ¶ 63,027 at P 118.

[425] *Id.* P 325.

b. Briefs on Exceptions

204. MISO TOs ask the Commission to reverse the Initial Decision and instead find that the expected earnings analysis provides a useful and probative benchmark for purposes of evaluating DCF results when anomalous capital market conditions justify consideration of alternative estimates of the cost of equity.[426] MISO TOs refer to the Presiding Judge's conclusion that Dr. Avera failed to follow the approach in Dr. Morin's *New Regulatory Finance*.[427]

205. MISO TOs assert that Dr. Avera's study was the same analysis submitted and accepted in Opinion No. 531 and, although the Presiding Judge argues that the Commission was not aware of Dr. Morin's statement that proxy groups should be made up of unregulated companies, the record in neither proceeding supports this inference.[428] MISO TOs assert that *New Regulatory Finance* does not mandate exclusive reliance on unregulated companies.[429] MISO TOs argue that Dr. Morin's critique of using regulated companies relates entirely to the application of the comparable earnings approach using historical data, which reflects in part past actions of other regulators and historical conditions. MISO TOs argue that this is distinct from the forward-looking expected earnings approach relied upon by the Commission in Opinion No. 531, which MISO TOs contend is no more susceptible to concerns over regulatory influence than the analysts' EPS growth rates that are used to apply the DCF model.[430]

206. MISO TOs argue that the critical inquiry for assessing the merits of an expected earnings analysis is whether the studied companies are of comparable risk to the utilities whose rates are at issue, not whether they are regulated.[431] MISO TOs further state that, although Dr. Avera conceded that expected earnings of non-regulated companies may also provide a logical benchmark for evaluating a just and reasonable ROE, this does not

[426] MISO TOs Brief on Exceptions at 2.

[427] *Id.* at 24 (citing Initial Decision, 153 FERC ¶ 63,027 at P 323).

[428] *Id.* at 25 (citing Initial Decision, 153 FERC ¶ 63,027 at P 323).

[429] *Id.* (citing Roger A. Morin, *New Regulatory Finance* 381 (Public Utilities Reports, Inc. 2006) (stating that "[t]he reference group is usually made up of unregulated industrial companies.")).

[430] *Id.* at 25-26.

[431] *Id.* at 26.

preclude consideration of other electric utilities' expected earnings. MISO TOs argue that *Principles of Public Utilities Rates* supports Dr. Avera's assertion that an analysis of comparable earnings may be conducted for "utilities or nonregulated firms."[432]

207. Finally, MISO TOs argue that the Presiding Judge failed to credit Dr. Avera's testimony regarding the use of the expected earnings model by the Virginia State Corporation Commission (Virginia Commission), which is required by statute to consider the earned returns on book value of electric utilities in its region and has established allowed ROEs based on earned returns on book value for peer groups of other electric utilities.[433] MISO TOs argue that Dr. Avera's point was to show that regulators do not consider the expected earning analysis to be useful only when applied to unregulated enterprises and that there is no reason to assume that the Virginia Commission's rationale for its practice is different than the rationale offered by Dr. Avera and Mr. Bonbright – that an expected earnings study of comparable enterprises can provide useful estimates of investor expectations.[434]

c. **Briefs Opposing Exceptions**

208. Complainants and other parties contend that the Commission should affirm the Presiding Judge's rejection of Dr. Avera's expected earnings analysis.[435] Complainants point out that Dr. Avera's methodology departs from Dr. Morin's prescribed method of composing a proxy group by using a group of electric utilities, rather than a group of unregulated companies.[436] Complainants argue that Dr. Avera was unable to justify this

[432] *Id.* (citing James C. Bonbright *et al.,* Principles of Public Utility Rates 329 (2d ed. 2006)).

[433] MISO TOs Brief on Exceptions at 27.

[434] *Id.*

[435] Complainants Brief Opposing Exceptions at 7-11; Trial Staff Brief Opposing Exceptions at 9-16; Iowa Group Brief Opposing Exceptions at 11-16; Joint Customer Intervenors Brief Opposing Exceptions at 8-17; OMS/Joint Consumer Advocates Brief Opposing Exceptions at 21-24.

[436] Complainants Brief Opposing Exceptions at 7 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 315-316, 323).

departure from Dr. Morin's expected earnings methodology such that their arguments should be rejected.[437]

209. Complainants assert that MISO TOs' arguments that the Commission was aware of Dr. Morin's statement that proxy group should be made up of unregulated companies are unpersuasive and made up of circumstantial evidence.[438] Complainants also disagree with MISO TOs' argument that this departure from Dr. Morin's expected earnings approach is permissible given the Commission's recognition of Dr. Morin as an authority on the expected earnings analysis.[439] According to Complainants, the record in this proceeding is lacking evidence that justifies such a departure. Complainants state that a plain reading of Opinion No. 531 demonstrates that the Commission was unaware of the proxy group flaw in the expected earnings analysis. Complainants assert that Dr. Avera's expected earnings results in circular ratemaking,[440] problems of which the Commission has recognized.[441]

210. Complainants contend that the Presiding Judge's rejection of Dr. Avera's expected earnings analysis was based on the record in this proceeding and represents reasoned decision making. According to Complainants, the Presiding Judge's rejection of Dr. Avera's expected earnings analysis does not affect the Presiding Judge's ultimate ROE recommendation and, by taking exception, MISO TOs are seeking what is effectively an inappropriate advisory opinion from the Commission.[442]

211. Complainants disagree with MISO TOs' argument regarding the Virginia Commission's use of a similar expected earnings methodology.[443]

[437] *Id.* at 8.

[438] *Id.* (citing MISO TOs Brief on Exceptions at 25-26).

[439] *Id.* at 8-9 (citing Initial Decision, 153 FERC ¶ 63,027 at P 315).

[440] *Id.* at 9 (citing Exh. S-1 at 97-98).

[441] *Id.* (citing *Minnesota Power and Light Co.*, Opinion No. 12, 3 FERC ¶ 61,045, at 61,132 (1978)).

[442] *Id.* at 9-10.

[443] *Id.* at 10 (citing MISO TOs Brief on Exceptions at 27).

Complainants assert that a mere description of a state Commission's purported use of this method is not sufficient to justify Dr. Avera's departure from Dr. Morin's guidance.[444]

212. Complainants also argue that the record demonstrates other flaws in Dr. Avera's expected earnings analysis. Complainants state that the non-regulated assets of MISO TOs can affect the expected return on their consolidated operations. Complainants also state that the earned return on book equity does not describe the return investors currently require to make an investment in the National Proxy Group of companies and, therefore, it does not establish what the current market cost of equity is for these companies.[445] Complainants note that, in addition to Mr. Gorman, the following witnesses testified that Dr. Avera's expected earnings study is fundamentally flawed and consequently produces unreliable results: Mr. Hill, Iowa Group's witness Mr. Parcel, Mr. Solomon, and Mr. Keyton.[446]

213. Trial Staff notes that the Presiding Judge relied on Mr. Keyton's observations that both the Commission, in Opinion Nos. 531 and 531-B, and Dr. Avera, in his testimony, referred extensively to Roger Morin's *New Regulatory Finance*.[447] Trial Staff argues, however, that Dr. Avera failed to follow the specific three step methodology outlined by Dr. Morin, and instead repeated the type of expected earnings analysis that he used in the Opinion No. 531 proceeding.[448]

214. Trial Staff objects to the use of utility book rates of return as data inputs for an expected earnings study, and asserts that doing so introduces an element of circularity into the analytical process. Trial Staff states that limiting the data field to regulated utilities perpetuates established allowed ROEs rather than estimating the current market costs of equity.[449] Despite MISO TOs' argument that circularity concerns have been

[444] *Id.* at 10 (citing Initial Decision, 153 FERC ¶ 63,027 at P 321).

[445] *Id.* at 10-11 (citing Exh. JC-9 at P 17).

[446] *Id.* at 11.

[447] Trial Staff Brief Opposing Exceptions at 10 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 315-323).

[448] *Id.* (citing Roger A. Morin, *New Regulatory Finance* 383 (Public Utilities Reports, Inc. 2006)).

[449] *Id.* at 11 (citing Exh. S-1 at 98).

obviated by Dr. Avera's use of projected Value Line rates of return on book equity,[450] Trial Staff contends that Dr. Avera's use of projected book rates of return intensifies rather than ameliorates the noted defect. Trial Staff states that if utilities are awarded an ROE on the basis of what Value Line expects them to earn, there is a clear likelihood that they will converge in the future.[451]

215. According to Trial Staff, Dr. Avera used the Value Line data for the period from 2017 to 2019 when shorter-term projections were also available.[452] Trial Staff argues that, given that the expected accuracy of predictive estimates decline as their temporal horizon increases, it would have been preferable for Dr. Avera to average the three available Value Line earned rate of return projections instead of relying solely on the most distant one.[453]

216. Trial Staff disagrees with MISO TOs' contention that the methodology used by Dr. Avera is analytically identical to the one the Commission accepted in Opinion No. 531. Trial Staff acknowledges that, in Opinion No. 531, the Commission cited Dr. Morin's treatise in support of use of this methodology as a check on DCF results.[454] However, according to Trial Staff, the general discussion of this issue in Opinion No. 531 can hardly be read as an endorsement of the particular calculations performed by Dr. Avera on the data he selected for his study. Trial Staff argues that, as with the case of the Commission's inadvertent use of Dr. Avera's dividend yield calculation in Opinion No. 531, the Commission cannot be held to have approved an expected earnings methodology that it had not substantively examined.[455]

217. Regarding MISO TOs' contention that other authorities, such as the Virginia Commission, find comparable earnings studies relying on regulated utility data to be acceptable, Trial Staff states that MISO TOs do not attempt to defend or even explain the

[450] *Id.* at 14 (citing MISO TOs Brief on Exceptions at 25-26 (noting that Dr. Morin generally discusses the use of historical data in his discussion of the comparable earnings methodology)).

[451] *Id.* at 14.

[452] *Id.* at 11-12 (citing Exh. S-1 at 100-101).

[453] *Id.* at 12 (citing Exh. S-1 at 100-101).

[454] *Id.* at 13 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147).

[455] *Id.* at 13-14.

rationale underlying that choice.[456] Furthermore, Trial Staff states that the Commission has expressly ruled on this issue, indicating its preference for the use of nonregulated firms in conducting a comparative earnings analysis.[457] Trial Staff asserts that neither Dr. Avera nor MISO TOs' brief on exception explain the rationale for the Virginia Commission's ROE determinations.[458]

218. Iowa Group asserts that an expected earnings analysis on regulated utilities produces a rate-making circularity that perpetuates allowed returns on equity rather than measuring the actual cost of capital. Iowa Group asserts that the authorities cited by MISO TOs each recognize and discuss this limitation.[459]

219. According to Iowa Group, the purpose of regulation is to produce the same result that would occur in an unregulated market and, therefore, focusing on regulated returns does not produce a reliable measure of the cost of equity for an unregulated firm.[460] Iowa Group states that conducting an expected earnings analysis based on a proxy group consisting solely of regulated utilities involves allowed returns on equity and requires setting a utility's return based on other utilities' returns. Iowa Group, therefore, states that a utility-based expected earnings study will reflect a regulated marketplace over time and that such a result is contrary to one of the fundamental economic principles of utility regulation. Iowa Group asserts that a historical versus forward-looking distinction is meaningless in this context, since both rely on regulated returns. [461]

220. Joint Customer Intervenors assert that Dr. Avera's expected earnings analysis was invalid because it was applied to regulated utilities, while his primary authority, *New Regulatory Finance*, states that the comparable earnings approach should only be

[456] *Id.* at 15.

[457] *Id.* at 15 (citing Opinion No. 12, 3 FERC at 61,132).

[458] *Id.* at 15 (citing Initial Decision, 153 FERC ¶ 63,027 at P 321.

[459] Iowa Group Brief Opposing Exceptions at 14-15 (citing James C. Bonbright, Principles of Public Utility Rates 329-330 (Public Utilities Reports, Inc. 2006); Roger A. Morin, *New Regulatory Finance* 383 (Public Utilities Reports, Inc. 2006); David C. Parcell, The Cost of Capital: A Practitioner's Guide 118-119 (2010)).

[460] *Id.* at 14.

[461] *Id.* at 16.

applied to a comparable risk group of unregulated companies.[462] Joint Customer Intervenors contend that MISO TOs cannot be permitted to rely on a source as a standard for analysis and then disregard that source at will.[463]

221. Joint Customer Intervenors object to MISO TOs' citation to *Principles of Public Utility Rates*, arguing that MISO TOs cite to this source for the first time in their brief on exceptions. Joint Customer Intervenors also note that MISO TOs omitted statements in *Principles of Public Utility Rates* that suggest that the issue of circularity is raised if the comparable earnings approach is applied to regulated utilities.[464]

222. Joint Customer Intervenors contend that MISO TOs' argument is anecdotal and without explanation for why or how the Virginia Commission applied its approach. Joint Customer Intervenors assert that MISO TOs failed to justify departure from the methodology that both Dr. Avera and the Commission have cited as the principal authority on the expected earnings model.[465]

223. In response to MISO TOs' argument that Opinion No. 531's cite to *New Regulatory Finance* demonstrates that the Commission was aware of Dr. Morin's prohibition on the use of regulated utilities in the expected earnings analysis, Joint Customer Intervenors assert that the prohibition was not discovered or brought to the Commission's attention in that proceeding.[466]

224. Joint Customer Intervenors assert that MISO TOs' reference to Dr. Morin's statement that "[t]he reference group is *usually* made up of unregulated industrial companies" is without context, does nothing to refute Dr. Morin's conclusion and

[462] Joint Customer Intervenors Brief Opposing Exceptions at 9-10 (citing Dr. Roger A. Morin, *New Regulatory Finance* 381-382 (Public Utilities Reports, Inc. 2006); Initial Decision, 153 FERC ¶ 63,027 at P 316).

[463] *Id.* at 13.

[464] *Id.* at 11 (citing MISO TOs Brief on Exceptions at 26; James C. Bonbright, Principles of Public Utility Rates 239-330 (Public Utilities Reports, Inc. 2006)).

[465] *Id.* at 12.

[466] *Id.* at 13-14 (citing MISO TOs Brief on Exceptions at 25).

rationale for excluding regulated utilities, and fails to recognize the multiple additional instances where Dr. Morin cautions against the use of regulated utilities.[467]

225. Joint Customer Intervenors assert that MISO TOs' claim that Dr. Morin's prohibition on the use of regulated utilities does not apply to forward-looking analyses amounts to a conclusory statement. Joint Customer Intervenors argue that this claim is refuted by Dr. Morin's recognition of the use of the projected comparable earnings approach, and by the absence of any statement by Dr. Morin that the projected comparable earnings approach ameliorates the issue of circularity.[468]

226. Joint Customer Intervenors note that Mr. Solomon explained that Dr. Avera's expected earnings analysis was not based on market data, but on projected returns on book equity, and that the Commission has historically rejected the comparable earnings method.[469] According to Joint Customer Intervenors, the Commission has recognized that the allowed rate of return shall be set "at the rate of return investors require on their investment" and that "when the price-to-book ratio is greater than one, the rate of return investors expect to earn on common equity is greater than the rate of return investors require from their investment in common stock."[470] Joint Customer Intervenors note that Dr. Avera's expected earnings analysis shows a midpoint of 11.44 percent and that the average price-to-book ratio for the proxy group is 1.79.[471]

227. Joint Customer Intervenors assert that an investor willing to pay more than the book value for a utility's expected earnings expects to earn something less than the expected earned rate of return on book value on that investment. Joint Customer Intervenors contend that the range for investors' required ROE should be bracketed by the earnings-to-price ratio and the expected earned rate on return on book value. Joint

[467] *Id.* at 14 (citing MISO TOs Brief on Exceptions at 25 & n.67; Dr. Roger A. Morin, *New Regulatory Finance* 381-382 (Public Utilities Reports, Inc. 2006)).

[468] *Id.* at 14-15 (citing MISO TOs Brief on Exceptions at 26; Dr. Roger A. Morin, *New Regulatory Finance* 385 (Public Utilities Reports, Inc. 2006)).

[469] *Id.* at 15 (citing Exh. JCI-4 at 49:14-20).

[470] *Id.* at 15 (citing *Orange and Rockland Utilities, Inc.*, 44 FERC ¶ 61,253, at 61,952 (1988) (*Orange and Rockland*)).

[471] *Id.* at 16 (citing Exh. JCI-4 at 50:14-17).

Customer Intervenors assert that the midpoint of that range is below the 9.29 percent midpoint of the Presiding Judge's DCF range.[472]

228. OMS/Joint Consumer Advocates state that Dr. Avera's inclusion of regulated utilities in his expected earnings sample group creates an inescapable circularity. According to OMS/Joint Consumer Advocates, a regulatory commission's actions necessarily will affect a utility's future earnings, a forecast of which, in turn, then becomes a factor in establishing the ROE in the next regulatory decision, which itself will then affect future earnings and forecasts thereof. OMS/Joint Consumer Advocates state that excluding regulated utilities from the sample group, as indicated to be necessary by the very source on which Dr. Avera relied,[473] is essential if such circularity is to be avoided.[474]

229. OMS/Joint Consumer Advocates state that MISO TOs give no indication in their brief on exceptions that the base ROE adopted in the Initial Decision would be any different had Dr. Avera's expected earnings study been accepted, nor would any such claim be plausible. OMS/Joint Consumer Advocates state that MISO TOs, therefore, seek nothing more than a request for Commission guidance about how the expected earnings method should be applied in other proceedings in the future. OMS/Joint Consumer Advocates contend that there are other avenues, more appropriate for the task, for obtaining generic guidance of that sort from the Commission.[475]

d. <u>Commission Determination</u>

230. We reverse the Presiding Judge's rejection of MISO TOs' expected earnings analysis. Complainants and Complainant-aligned parties assert that MISO TOs' expected earnings analysis is flawed for a variety of reasons. As discussed in more detail below, we disagree with these assertions and find that the results of MISO TOs' expected

[472] *Id.* at 16-17.

[473] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 22 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 315, 320, and 323).

[474] *Id.* (citing Opinion No. 12, 3 FERC at 61,132 (stating that "while the comparative earnings technique can be helpful in determining whether an allowed rate of return is commensurate with the return on investments in other enterprises, if the comparison is only with regulated companies, there is a certain circularity.")).

[475] *Id.* at 23.

earnings analysis corroborates our determination that MISO TOs should be awarded an ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.[476]

231. The Presiding Judge's rejection of MISO TOs' expected earnings analysis relies on the premise that Dr. Morin's guidance in *New Regulatory Finance* precludes the inclusion of regulated companies in expected earnings proxy groups.[477] MISO TOs argue that *New Regulatory Finance* does not mandate exclusive reliance on unregulated companies in forward-looking expected earnings analyses. We agree. In particular, we note that that conclusion is consistent with Dr. Morin's analysis in *New Regulatory Finance*:

> In defining a population of comparable-risk companies, care must be taken not to include other utilities in the sample, since the rate of return on other utilities depends on the allowed rate of return. The *historical* book return on equity for regulated firms is not determined by competitive forces but instead reflects the *past* actions of regulatory commissions. It would be circular to set a fair return based on the *past* actions of other regulators, much like observing a series of duplicative images in multiple mirrors. The rates of return earned by other regulated utilities may well have been reasonable under historical conditions, but they are still subject to tests of reasonableness under current and prospective conditions.[478]

Dr. Morin's recommendation to avoid other utilities in the sample is based on his concern that the use of historical book ROE would be based on past actions of regulatory commissions and, therefore, reliance on those past actions to set an ROE would raise issues of circularity. However, MISO TOs' expected earnings analysis is forward-looking and based on Value Line forecasts, adjusted to reflect each utility's average return.[479] As the Commission explained in Opinion No. 531-B, an expected earnings analysis, in contrast to a comparable earnings

[476] Our analysis below does not rely on the arguments regarding the Virginia Commission's use of expected earnings analyses; therefore, we dismiss such arguments as moot.

[477] *See* Initial Decision, 153 FERC ¶ 63,027 at P 323.

[478] Dr. Roger A. Morin, *New Regulatory Finance* 383 (Public Utilities Reports, Inc. 2006) (Emphasis supplied).

[479] *See* Initial Decision, 153 FERC ¶ 63,027 at P 314.

analysis, is sound when it is forward-looking and based on a reliable source of earnings data.[480]

232. Moreover, while Complainants and Complainant-aligned parties refer to various other excerpts from Dr. Morin's *New Regulatory Finance*, each appears to refer to comparable earnings analyses that are based on historical earnings on book value.[481] Thus, even if the Commission did not consider Dr. Morin's statement that proxy groups for comparable earnings analyses should be made up of unregulated companies, that statement alone does not invalidate MISO TOs' expected earnings analysis.

233. We disagree with Complainant-aligned parties' assertions that MISO TOs' expected earnings analysis will nevertheless raise issues of circularity or lead to the convergence of Commission-approved ROEs and the Value Line projections. MISO TOs' zone of reasonableness, in which Commission-approved ROEs are placed, is established by the results of the DCF study. The expected earnings analysis, like the other alternative methodologies accepted herein, is merely used as corroborative evidence. Therefore, we are not persuaded that our acceptance of the expected earnings analysis, which at most can corroborate the Commission's decision to place an ROE above the midpoint of the zone of reasonableness, will raise issues of circularity or lead to a convergence of Commission-approved ROEs to the Value Line projections.

234. We also disagree with Complainants' contention that MISO TOs' expected earnings analysis is flawed because the return on book value does not establish the current market cost of equity for proxy group companies.[482] As the Commission explained in Opinion No. 531-B, investors rely upon the return on book equity to determine the opportunity cost of investing in a particular company, and investors rely upon expected earnings analysis for this purpose without attempting to convert that

[480] Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 125-126. *See, e.g.*, *Southern California Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, at 61,263 (2000) (finding it necessary to adjust Value Line's forecasted returns on book equity to reflect average returns rather than year-end returns); *see also* Roger A. Morin, *New Regulatory Finance* 305-306 (Public Utilities Reports, Inc. 2006).

[481] *See, e.g.*, Dr. Roger A. Morin, *New Regulatory Finance* 382 (Public Utilities Reports, Inc. 2006) (providing the three steps required to implement a comparable earnings analysis).

[482] This appears to be another way of saying that MISO TOs' expected earnings analysis did not consider market-to-book ratios.

opportunity cost into the current market cost of equity.[483] Therefore, consistent with Opinion No. 531-B, we find MISO TOs' expected earnings analysis reliable as corroborative evidence in this proceeding, notwithstanding the lack of a market-to-book adjustment in their analysis. Furthermore, even assuming *arguendo* that a market-to-book adjustment was appropriate, we are not persuaded that Joint Customer Intervenors' approach would accurately estimate the utility's market cost of equity.[484]

235. We also disagree with Joint Customer Intervenors' reliance on *Orange & Rockland* in crafting their argument that the expected earnings analysis cannot be relied upon because the market-to-book ratio of the proxy group exceeds one.[485] As the Commission explained in Opinion No. 531-B, *Orange & Rockland* did not involve a comparable earnings analysis; it involved a proposal to alter the DCF model by adjusting the dividend yield to reflect the expected earnings of the company whose rates were at issue in that proceeding.[486] MISO TOs do not make such a proposal. Instead, MISO TOs have submitted an expected earnings analysis based on their national proxy group of utilities with comparable risk profiles to MISO TOs. Therefore, unlike *Orange & Rockland*, where the Commission rejected a proposal that would have had the effect of setting the base ROE at the company's own expected ROE, MISO TOs' expected earnings analysis is only relevant to the determination of whether the midpoint of the DCF-produced zone of reasonableness provides a market cost of equity sufficient to meet the requirements of *Hope* and *Bluefield*.[487] The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk. Such a calculation is consistent with the requirement in *Hope* that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[488]

[483] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 132.

[484] *See* Joint Customer Intervenors Brief Opposing Exceptions at 16.

[485] *Id.* at 15 (citing *Orange and Rockland*, 44 FERC ¶ 61,253 at 61,952 (*Orange and Rockland*)).

[486] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 127.

[487] *Id.* P 128.

[488] *Hope*, 320 U.S. at 603; *see also Petal Gas Storage, L.L.C.*, 496 F.3d 695

236. As the Commission explained in Opinion No. 531-B,[489] investors rely on both the market cost of equity and the book return on equity in determining whether to invest in a utility, because investors are concerned with both the return the regulator will allow the utility to earn *and* the company's ability to actually earn that return. If, all else being equal, the regulator sets a utility's ROE so that the utility does not have the opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility. Thus, all else being equal, an investor is more likely to invest in a utility that it expects will have the opportunity to earn a comparable amount on its book equity as other enterprises of comparable risk are expected to earn. Because investors rely on expected earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in corroborating whether the results produced by the DCF model may have been skewed by the anomalous capital market conditions reflected in the record.

237. We are also not persuaded by Trial Staff's assertion that MISO TOs should have also considered shorter term Value Line projections than the 2017-2019 projects they used. While Trial Staff asserts that shorter term projections were available to MISO TOs, it is unclear if those shorter term projections would have resulted in materially different results. Therefore, we are not persuaded that MISO TOs' reliance on Value Line projections for 2017-2019 undermined the usefulness of MISO TOs' expected earnings analysis as corroborative evidence.

238. We also reject the arguments that MISO TOs' exception to the Presiding Judge's rejection of their expected earnings analysis has no relevance on this proceeding and is effectively an attempt to receive general guidance from the Commission. While it is true that, despite his rejection of MISO TOs' expected earnings analysis, the Presiding Judge elected to set the ROE at the upper midpoint of the DCF-produced zone of reasonableness, the placement of the ROE was disputed by Complainants and Complainant-aligned parties in their briefs on exceptions. Given that the expected earnings analysis can further corroborate our finding that a mechanical application of the DCF methodology does not satisfy *Hope* and *Bluefield*, MISO TOs' exception to the Presiding Judge's rejection of their expected earnings analysis is appropriate.

(D.C. Cir. 2007).

[489] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 129.

239. For the reasons stated above, we reverse the Presiding Judge's rejection of MISO TOs' expected earnings analysis.[490] We find that MISO TOs' expected earnings analysis is sufficiently reliable to be used as corroborative evidence that the midpoint of the zone of reasonableness produced by the mechanical application of the DCF methodology does not result in a return that satisfies the requirements of *Hope* and *Bluefield*.

5. State ROEs

240. MISO TOs' witness, Ms. Lapson, presented evidence that all state-authorized ROEs during the period April 1, 2013 through March 31, 2015 for integrated electric utilities providing generation, transmission, and distribution services ranged from 9.5 percent to 10.4 percent.[491] In addition, 87.34 percent of state-authorized ROEs for both integrated electric utilities and distribution-only electric utilities during that period were within this range. Ms. Lapson also testified that investing in Commission-regulated electric transmission involves significant risks that investment in other utilities does not and that setting MISO TOs' ROE at a level generally below state-authorized ROEs will make investment in interstate electric transmission less attractive than investment in conventional electric utility activities.

a. Initial Decision

241. The Presiding Judge determined that the state-authorized ROEs in the record support setting MISO TOs' base ROE above the midpoint of the DCF zone of reasonableness. The Presiding Judge observed that the midpoint of the DCF zone of reasonableness is lower than all of the state-authorized ROEs for integrated electric utilities and two-thirds of the state-authorized ROEs for distribution-only utilities. The Presiding Judge noted that MISO TOs face risks that are at least as great as the risks facing both categories of companies.[492] The Presiding Judge rejected arguments regarding the data used to identify the state-authorized ROEs, noting that, consistent with Opinion Nos. 531 and 531-B, this data reflected the most recent data in the record.[493] The Presiding Judge also rejected the argument that the 50 basis point incentive ROE adder should be considered in setting the base ROE, noting that the Commission flatly

[490] *See* Initial Decision, 153 FERC ¶ 63,027 at P 323.

[491] Exh. MTO-42 at 1-2.

[492] Initial Decision, 153 FERC ¶ 63,027 at PP 454-456.

[493] *Id.* PP 366-367.

rejected this argument in Opinion No. 531.[494] Finally, the Presiding Judge rejected a host of arguments contending that differences in the risk profile of the state-regulated utilities rendered base ROE comparisons inapt.

b. Briefs on Exceptions

242. OMS states that the Presiding Judge interpreted Opinion No. 531-B as requiring that he give more weight to the fact that the average state-authorized ROE exceeded the DCF midpoint than to the demonstrated downward trajectory in state-authorized ROEs.[495] OMS argues that, in this regard, the Presiding Judge misconstrues Opinion No. 531-B. According to OMS, the Commission did not, in that instance, consider and dismiss a proven downward movement in state ROEs; rather, it simply found that the record lacked proof of such a downward trend.[496] OMS states that the record evidence clearly shows a downturn in state-authorized ROEs over the past decade continuing through the DCF study period. It further contends that the failure of Ms. Lapson's study to account for this trend is a "fatal flaw" that disqualifies the study for use as support for setting the base ROE above the midpoint.[497] Furthermore, OMS contends that the downward trend in state-authorized ROEs should alleviate concerns about capital being shifted away from transmission investments into distribution investments.

243. OMS further argues that, in Opinion No. 531, the Commission compared the investment risks of electric infrastructure with those of electric distribution infrastructure and concluded that the Commission-approved ROE for transmission assets should be higher than the state-authorized ROEs for distribution assets.[498] OMS avers that the basis for this finding was the Commission's determination that investing in transmission carries greater risk than investing in distribution. However, OMS states that Ms. Lapson's analysis is based solely on state-authorized ROEs for integrated utilities, and that Ms. Lapson consciously avoided using data from distribution-only companies.[499]

[494] *Id.* P 380.

[495] OMS Brief on Exceptions at 38-39 (citing Initial Decision, 153 FERC ¶ 63,027 at P 363).

[496] *Id.* at 39 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at n.176).

[497] *Id.*

[498] *Id.* at 40 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 149).

[499] *Id.* (citing Exh. MTO-16 at 54:5-14 and OMS Reply Brief at 31).

244. OMS states that the Presiding Judge found that the mean, median, and midpoint of the state-authorized ROEs for distribution-only utilities (9.45 percent, 9.55 percent, and 9.41 percent, respectively) are above the midpoint of the DCF analysis adopted in the Initial Decision (i.e., 9.29 percent).[500] OMS contends, however, that the mean and the midpoint of the state-authorized ROE numbers for distribution-only utilities are below the base ROE of 9.54 percent recommended by Mr. Gorman and that the median is only 0.01 percent above Mr. Gorman's proposed ROE for MISO TOs.[501] OMS states that, to the extent that state-authorized ROEs for distribution-only utilities are a meaningful consideration in setting transmission ROEs, the base ROE proposed by the Complainants in this proceeding is reasonable and sufficient.

245. OMS also asserts that the Commission should reject the Presiding Judge's finding that investing in MISO TOs' Commission-regulated electric transmission entails risks that are at least as great as the risks of investing in the integrated electric utilities analyzed by Ms. Lapson, and therefore it would be illogical to award a base ROE for MISO TOs that is below the state-authorized ROEs of these integrated electric utilities.[502] OMS states that there is no evidence in the record that supports the proposition that the risks assumed by MISO TOs, or by transmission companies in general, are at least as great as those of the integrated utilities studied by Ms. Lapson. On the contrary, OMS states that evidence presented by Mr. Hill indicates that the risks of transmission service are less than the risks of integrated utility operations, which include the risks of competitive operations.[503] Joint Customer Intervenors similarly argue assert that the Presiding Judge failed to consider evidence demonstrating that the formula rate-based transmission service at issue here is less risky than the integrated generation and distribution service regulated by the state commissions.[504]

246. OMS also states that, should the Commission find that MISO TOs are largely or predominantly integrated or that MISO TOs have risks "at least as great" as those of integrated utilities, an upward adjustment from the DCF midpoint based on comparing utilities having similar risk profiles would not be supportable here. OMS reiterates

[500] *Id.* at 41 (citing Initial Decision, 153 FERC ¶ 63,027 at P 400).

[501] *Id.* (citing Exh JC-1 at 2:13; Exh. JC-9 at 32:7-8).

[502] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 453).

[503] *Id.* at 41-42 (citing Exh. JCA-1 at 35:17-22).

[504] Joint Customer Intervenors Brief on Exceptions at 47-48 (citing Exh. JCI-4 at 32:21-36:2).

its Reply Brief argument that an upward adjustment of the base ROE in reliance on Ms. Lapson's state ROE benchmark would not compensate investors by an amount that is in any way linked to the risks that purportedly exceed those associated with distribution companies. Rather, according to OMS, it would simply confer on investors in transmission infrastructure a premium, but one that has no nexus to the risks it is meant to address.[505] OMS states that over-compensating investors for transmission risks is not without its own adverse impacts, including potentially reducing the amount of capital available for other necessary electric infrastructure investments.

247. Joint Customer Intervenors state that the Commission, prior to Opinion No. 531, had long held that wholesale ROE determinations should not be influenced by state-authorized ROEs.[506] Joint Customer Intervenors also argue that incentives should be taken into consideration when comparing the base ROEs awarded to MISO TOs in this proceeding to the state-awarded ROEs. Joint Customer Intervenors assert that it is inappropriate to compare state-awarded ROEs that do not include incentives to Commission-awarded ROEs that do not include incentives.[507]

248. Joint Customer Intervenors explain that Mr. Solomon presented an analysis by SNL Financial that demonstrated that the overwhelming majority of electric utilities are not able to earn their state-awarded ROEs, while MISO TOs' transmission formula rates provide assurance that MISO TOs are able to earn their Commission-awarded ROE. Joint Customer Intervenors state that the utilities in the SNL Financial study earned ROEs that were, on average, 120 basis points below their state-awarded ROEs. Joint Customer Intervenors therefore argue that MISO TOs' ROE should not be compared to state-awarded ROEs but should instead be compared to the ROEs that utilities can reasonably be expected to earn under those state-awarded ROEs.[508]

[505] OMS Brief on Exceptions at 42 (citing OMS Reply Brief at 32).

[506] Joint Customer Intervenors Brief on Exceptions at 47 (citing *Middle S. Services, Inc.*, Opinion No. 124, 16 FERC ¶ 61,101, at 61,221 (1981); *Boston Edison Co.*, Opinion No. 411, 77 FERC ¶ 61,272, at 62,172 (1996); *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009 (1996)).

[507] *Id.* at 48-49.

[508] *Id.* at 49-50 (citing Exh. JCI-7 at 110-113).

c. Briefs Opposing Exceptions

249. MISO TOs argue that the Presiding Judge properly credited Ms. Lapson's state ROE evidence and correctly found that wholesale transmission is at least as risky as an integrated electric utility and more risky than a distribution-only electric utility.[509] MISO TOs agree that Ms. Lapson's study supports allowing MISO TOs to collect a base ROE above the midpoint, as the DCF midpoint is lower than all the state-authorized ROEs for integrated utilities and lower than two-thirds of the distribution-only electric utilities' state-authorized ROEs.[510] MISO TOs argue that, given "the clear Commission precedent support consideration of state-authorized" ROEs, the Presiding Judge correctly discredited the arguments made in Joint Customers' and OMS's exceptions, which MISO TOs assert, were previously rejected in Opinion Nos. 531 and 531-B.[511] In particular, MISO TOs contend that the Presiding Judge correctly disregarded arguments that the downward trend in state ROEs undermined the usefulness of Ms. Lapson's evidence. Additionally, MISO TOs argue that it is equally unpersuasive for Joint Customers to argue that the Presiding Judge erred by excluding from consideration any ROE incentives awarded under FPA section 219.[512]

d. Commission Determination

250. We agree with the Presiding Judge that the state-authorized ROE study by Ms. Lapson corroborates the finding that a mechanical application of the DCF methodology does not satisfy *Hope* and *Bluefield*. We do so because the 9.29 percent midpoint calculated by the Presiding Judge's DCF study is lower than all of the state-authorized ROEs of integrated electric utilities and most of the distribution-only utilities in that study and because investing in MISO TOs' Commission-regulated electric transmission entails risks that are "at least as great" as those faced by investors in integrated electric utilities.[513] In Opinion No. 531, the Commission found that record evidence of state commission-approved ROEs supported adjusting the New England transmission owners' base ROE above the midpoint of the zone of reasonableness. In that decision, the Commission stated that it was not "using state commission-approved

[509] MISO TOs Brief Opposing Exceptions at 31.

[510] *Id.* at 32.

[511] *Id.* at 32-33 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 353-81).

[512] *Id.* at 33.

[513] Initial Decision, 153 FERC ¶ 63,027 at P 455.

ROEs to establish the . . . ROE" but that the Commission found that "the discrepancy between state ROEs and the . . . midpoint serve[d] as an indicator that an adjustment to the midpoint . . . is necessary to satisfy *Hope* and *Bluefield*."[514] In Opinion No. 531-B, the Commission further explained that "the Commission merely relied on the state commission-authorized ROEs – in conjunction with evidence that interstate transmission is riskier than state-level distribution – as evidence that the . . . midpoint of the . . . zone of reasonableness was insufficient to satisfy . . . *Hope* and *Bluefield*."[515] We find that the rationale employed there justifies our adoption of the Presiding Judge's finding with regard to Ms. Lapson's study.

251. We also find that OMS's and Joint Customer Intervenors' claims about a downward trend in overall state-authorized ROEs from 10.54 percent in 2005 to 9.58 percent during the first six months of 2015, are not enough, in and of themselves, to overcome the fact that the midpoint is below the vast majority of state-authorized ROEs that became effective during the April 1, 2013 through March 31, 2015 period of Ms. Lapson's study.[516] As noted above, the relevance of the study is to examine whether a survey of state-authorized ROEs might support making an upward adjustment to the Commission-allowed ROE. A study demonstrating that the vast majority of state-authorized ROEs studied exceed the midpoint of the zone of reasonableness suggests that the midpoint of that zone may be too low, and the asserted downward trend in state-authorized ROEs does not, in and of itself, counter this suggestion. First, irrespective of any downward trend in overall state commission-approved ROEs, the fact remains that every single state commission-approved ROE for a vertically integrated utility in the April 1, 2013 through March 31, 2015 study period exceeded the midpoint of the Presiding Judge's DCF study, including those in the first three months of 2015. Mr. Gorman's study, which asserted that the average of state-authorized ROEs declined to 9.58 percent during the first six months of 2015, included distribution-only electric utilities, as well as integrated electric utilities.[517] In addition, Mr. Gorman's 9.58 percent figure is still above the 9.29 percent midpoint of the DCF zone of reasonableness. Moreover, Mr. Gorman excluded base ROEs authorized by the Virginia Commission. As the Presiding Judge pointed out, inclusion of the Virginia Commission-authorized ROEs would have raised the average of the state-authorized ROEs approved in the first half of

[514] Opinion No. 531, 147 FERC ¶ 61,234 at P 148.

[515] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 84.

[516] Initial Decision, 153 FERC ¶ 63,027 at P 353.

[517] Exh. JC-26 at 1.

2015 to 10.09 percent,[518] 80 basis points above the 9.29 percent midpoint of the DCF zone of reasonableness.

252. We further disagree with OMS that Ms. Lapson's analysis is "based solely on state-authorized ROEs for *integrated* utilities" and that "she consciously avoided using data from distribution-only companies."[519] As the Presiding Judge noted, Ms. Lapson's study includes data from distribution-only utilities.[520] Additionally, OMS makes arguments comparing the mean and midpoint of the state-authorized ROE numbers for distribution-only utilities to the 9.54 percent base ROE recommended by Mr. Gorman. Again, we note that the Ms. Lapson's study's only relevance is to determine whether state-authorized ROEs are higher than the midpoint of the DCF zone of reasonableness. The study does not prescribe where in the zone of reasonableness the base ROE should be established. Ms. Lapson's study clearly indicates that the 9.29 percent midpoint is lower than all of the state-authorized ROEs of integrated electric utilities in the study and lower than two-thirds of all of the state-authorized ROEs of distribution-only electric utilities in the study.[521]

253. We also disagree with arguments that the record does not contain evidence that MISO TOs and other transmission companies face risks that are at least as great as the risks of investing in integrated electric utilities. Ms. Lapson's study contains an extended discussion of the risks faced by MISO TOs and transmission owners in general.[522] For instance, Ms. Lapson explains that developing interstate electric transmission is subject to "controversy and public opposition" and "subject to the requirements of multiple jurisdictions," which can increase project complexity and force transmission developers to "make economic concessions to . . . gain approvals."[523] Furthermore, Ms. Lapson states that transmission-owning utilities face "execution risks in completing the project and the risk that parties may seek to disallow rate recovery of any cost overruns."[524]

[518] Initial Decision, 153 FERC ¶ 63,027 at P 370.

[519] OMS Brief on Exceptions at 40.

[520] *See*, *e.g.*, Initial Decision, 153 FERC ¶ 63,027 at PP 338, 401, 402.

[521] Initial Decision, 153 FERC ¶ 63,027 at PP 455-56.

[522] *See id.* PP 340-48.

[523] Exh. MTO-39 at 40:14, 18-22.

[524] *Id.* at 40: 22-24.

Lapson also notes that medium or small utilities, such as "quite a few of the MISO [TOs]" require external funding, a consideration which creates uncertainty associated with capital market conditions and access to the debt and equity markets.[525]

254. Ms. Lapson also asserts that MISO TOs have capital expenditure (capex) commitments higher than most electric utilities and observes that utilities with high capex are exposed to execution or implementation risks associated with large capital investment, risks associated with the fact that "nearly all of the MISO TOs are invested in capex in excess of their internal cash from operations," and risks associated with the need for external financing.[526] Additionally, we note, and agree with, the Presiding Judge's conclusion that "investment in electric transmission poses a number of unique risks that investment in integrated electric utilities does not" and that investment in "MISO TOs' transmission entails additional risks due to the owners' high capex requirements."[527]

255. We also disagree with Joint Customer Intervenors' argument that "failing to consider the incentives included in state-awarded ROEs and then comparing them to FERC-awarded ROEs that do not include incentive adders is inappropriate on its face."[528] Ms. Lapson stated that she removed all incentive adders from the state-authorized ROEs included in her study, and the Presiding Judge found that the other parties had not provided evidence to show that any of the state-authorized ROEs included in her study did include such incentives.[529] It is appropriate to compare state-authorized ROEs that do not include incentive adders with FERC-approved ROEs that also do not include incentive adders, as Ms. Lapson did. As the Commission explained in Opinion No. 531, "[a]lthough section 219 of the FPA gives [the Commission] authority to provide incentives above the base ROE, nothing in section 219 relieves [the Commission] from first setting the base ROE at a place that meets *Hope* and *Bluefield*."[530] Since the base

[525] *Id.* at 41:1-6.

[526] Initial Decision, 153 FERC ¶ 63,027 at PP 342-347 (citing Exh. MTO-16 at 40:4-5, 13-15.

[527] Initial Decision, 153 FERC ¶ 63,027 at P 397 (citing Exh. MTO-16 at 35, Table 3, 40:4-19, 41:10-42:12; Moody's Rating Methodology, Regulated Electric and Gas Utilities, December 23, 2013 at 24).

[528] JCI Brief on Exceptions at 49.

[529] Exh. MTO-16 at 52. Initial Decision, 153 FERC ¶ 63,027 at P 374.

[530] Opinion No. 531, 147 FERC ¶ 61,234 at P 153.

ROE must therefore not include incentives, it would be equally inappropriate to compare state-authorized ROE data that includes state-awarded ROE incentives.

256. Joint Customer Intervenors also argue that the Commission should not compare MISO TOs' ROE to state-awarded ROEs, but should instead compare MISO TOs' ROE to the state-awarded ROEs that utilities can expect to actually earn. Again, Ms. Lapson's conclusions serve as one indicator among several suggesting that the 9.29 percent midpoint of the DCF-produced zone of reasonableness is insufficient to satisfy *Hope* and *Bluefield*. That is, these conclusions, along with the other alternative methodologies described above have convinced us to set the base ROE above the midpoint in this proceeding. The survey does not, and should not, serve to prescribe the Commission's placement of the base ROE at any particular point within the zone of reasonableness. Additionally, we find that evidence that Joint Customer Intervenors provide to argue that not all utilities can expect to actually earn the state-authorized ROE they are permitted earn is both incomplete and not wholly supportive of their argument here.[531]

6. Impact of Base ROE on Planned Investment

a. Initial Decision

257. The Presiding Judge concluded that setting MISO TOs' base ROE at the midpoint of the zone of reasonableness "could undermine their ability to attract capital for new investment in electric transmission."[532] The Presiding Judge reviewed the evidence provided by Mr. Kramer, observing, in particular, that the 2014 MISO Transmission Expansion Plan (MTEP) contemplated roughly $20 billion of investment in transmission facilities. The Presiding Judge recounted how Ms. Lapson explained that MISO TOs' ROE was one of their primary sources of cash flow, which they used to fund investment in new transmission facilities.[533] In addition, she noted that this cash flow also helped to demonstrate MISO TOs' financial health to investors. Too large a reduction in base ROE would thus both cut off their cash flow as a significant source of investment capital and make it more difficult for MISO TOs to attract reasonably priced capital. Limited access to capital could, in turn, force MISO TOs to divert investment from projects contemplated in the MTEP and instead toward transmission projects for local reliability, which they are obligated to build.[534] In addition, the Presiding Judge also noted

[531] Exh. JCI-4 at 34:1-12.

[532] Initial Decision, 153 FERC ¶ 63,027 at P 480.

[533] *Id.* PP 465-466.

[534] *Id.* PP 468-469.

Ms. Lapson's observation that a large ROE reduction could create continued uncertainty, reducing investor interest in transmission-owning entities more generally.[535]

258. In reaching those conclusions, the Presiding Judge rejected the argument that the fact that the MISO TOs had not yet cancelled or deferred any transmission projects, even though they expected some reduction in base ROE, demonstrated that an ROE reduction was unlikely to reduce their investment in transmission infrastructure. The Presiding Judge explained that Ms. Lapson's testimony indicated that too large an ROE reduction would impair new investment, not that any reduction whatsoever would have that effect.[536] The Presiding Judge explained that, in Opinion No. 531, the Commission relied on evidence showing that a 175 basis-point reduction in ROE "*could*" reduce transmission investment. The Presiding Judge therefore concluded that Opinion No. 531 was consistent with the conclusion that reducing MISO TOs' base ROE from its current level to the midpoint of the zone of reasonableness, a 310-basis-point reduction, could undermine their ability to attract new capital to invest in transmission infrastructure.[537]

b. <u>Briefs on Exception</u>

259. Joint Customer Intervenors argue that the evidence did not demonstrate a correlation between the ROE and the level of transmission investment. According to Joint Customer Intervenors, Mr. Kramer stated that "he does not know what would have happened" when asked whether the amount of new projects would have exceeded the levels he cited if the Commission had allowed a return higher than the current 12.38 percent ROE.[538] Joint Customer Intervenors also claim that Mr. Kramer was unable to provide "evidence that indicates whether or not the same benefits would or would not have been achieved . . . under the suggested hypothetical of a lower base ROE."[539] Joint Customer Intervenors further argue that Ms. Lapson's statements, while relied upon by the Initial Decision, merely assert that a reduction in ROE would result in a reduction in earnings and cash flow, and that credit ratings might be affected.[540]

[535] *Id.* P 471.

[536] *Id.* PP 473-475.

[537] Initial Decision, 153 FERC ¶ 63,027 at PP 476-477.

[538] Joint Customer Intervenors Brief on Exceptions at 52-53 (citing Ex. JCI-14 at 1).

[539] *Id.* at 53 (citing Ex. JCI-13 at 1).

[540] *Id.* at 54 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 463-470).

Joint Customer Intervenors assert that there is no evidence in the record suggesting that their proposed base ROE would do any harm to transmission investment in the MISO region.[541]

c. Briefs Opposing Exception

260. MISO TOs argues that Joint Customers wrongly suggest that the Presiding Judge was required to quantify the precise ROE necessary to sustain transmission investment, as such precision is not required by the FPA.[542] Additionally, MISO TOs argue that the Presiding Judge "cited ample record support" to support his conclusion that setting the DCF at the midpoint of zone of reasonableness would have placed MISO TOs' base ROE below the ROE available for comparable or less risky investments, thereby impairing MISO TOs ability to compete for capital.[543] In particular, they note that the Presiding Judge adequately responded to the contention that federally regulated transmission mission facilities are less risky than those subject to state regulation and, therefore, that the federally regulated entities could still adequately attract capital, even if they are receiving a lower ROE.

d. Commission Determination

261. We affirm the Presiding Judge's conclusion that setting MISO TOs' base ROE at the midpoint of the zone of reasonableness could impair investment in transmission facilities. As the Commission explained in Opinion No. 531, adequate transmission investment supports the Commission's responsibility to ensure that rates are just and reasonable because new transmission facilities help to "promote efficient and competitive electricity markets, reduce costly congestion, enhance reliability, and allow access to new energy resources, including renewables."[544] We continue to find that this is the case, including for the $20 billion of transmission investment contemplated by the 2014 MTEP.[545]

[541] *Id.*

[542] MISO TOs Brief Opposing Exceptions at 37.

[543] *Id.*

[544] Opinion No. 531, 147 FERC ¶ 61,234 at P 150.

[545] Initial Decision, 153 FERC ¶ 63,027 at PP 459, 461.

262. We find that reducing MISO TOs ROE to the midpoint of the zone of reasonableness could, as Ms. Lapson and Mr. Kramer explained, put at risk the MTEP investments as well as those in other beneficial transmission facilities. By reducing MISO TOs' cash flow, an overly large ROE reduction will reduce MISO TOs' ability to fund new transmission investment with the profits from their existing operations. In addition, an overly large ROE reduction could cause MISO TOs' credit ratings and/or other measures of financial health to deteriorate, impairing their ability to raise external capital to fund new transmission facilities. In particular, as Ms. Lapson explained, a "radical reduction" in MISO TOs ROE could cause investors to shift their capital to state-regulated utilities, which may have a similar risk to MISO TOs and, as discussed above, may earn an ROE greater than the midpoint of the zone of reasonableness, making them significantly more attractive investments. As she explained, a recent UBS report identified a "perception" that "investors were already beginning to react to the potential for lower [b]ase ROEs by shifting their investment capital to [state-regulated] electric and gas retail distribution investments and away from wholesale electric transmission."[546]

263. We conclude that reducing MISO TOs' ROE to the midpoint of the zone of reasonableness could be sufficient to bring about those results. As the Presiding Judge explained, in Opinion No. 531, the Commission concluded that a 175-basis-point ROE reduction—from an ROE of 11.14 to an ROE of 9.39—could put transmission investment at risk.[547] The same is true here. Based on the evidence in this proceeding, we conclude that a base ROE reduction nearly twice as large as the Commission considered in Opinion No. 531 — that is, a reduction from an ROE of 12.38 to an ROE of 9.29 — is at least as likely to put transmission investment at risk as was the reduction contemplated in Opinion No. 531. Thus, as in Opinion No. 531, we find that the potential for reduced transmission investment counsels against a mechanical application of the DCF.[548]

264. Joint Customer Intervenors' arguments do not require a contrary conclusion. In particular, we note that the Commission has never required a demonstrated correlation between a particular ROE level and a particular level of transmission investment or that a reduction in ROE will cause particular harms to customers within MISO. Further, the Commission, in Opinion No. 531, concluded that evidence that a certain ROE reduction "could" imperil transmission investment militated against imposing such a reduction.[549]

[546] *Id.* P 350 (citing Exh. MTO-44).

[547] *Id.* P 479 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 150).

[548] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 150.

[549] *Id.*

For the reasons discussed, we conclude that the evidence in the record suggests that setting MISO TOs' base ROE at the midpoint of the zone of reasonableness could impair their ability to invest in new transmission infrastructure.

265. Based on the presence of anomalous capital market conditions and informed by the returns indicated by the CAPM, expected earnings, and risk premium analyses discussed above, we find that the ROE for MISO TOs should be above the midpoint of the zone of reasonableness established by the DCF analysis. We now turn to the issue of precisely where in the upper half of the zone of reasonableness to set MISO TOs' ROE.

7. Placement of the Base ROE above the Midpoint

a. Initial Decision

266. The Presiding Judge concluded that the presence of anomalous market conditions justified an ROE above the midpoint of the zone of reasonableness. The Presiding Judge concluded that, consistent with Opinion No. 531, it was appropriate to set the base ROE at the midpoint of the upper half of the zone of reasonableness.[550]

b. Briefs on Exceptions

267. Joint Customer Intervenors contend that, to the extent that capital market conditions were anomalous and such conditions justified a return higher than the midpoint of the zone of reasonableness, the appropriate point would be the 75th percentile of the zone of reasonableness. They state that their witness, Mr. Mr. Solomon testified that the 75th percentile is the point in the zone of reasonableness at which 25 percent of the proxy companies have higher ROEs and 75 percent of the proxy companies have lower ROEs. Joint Customer Intervenors argue that, while the Initial Decision stated that the Commission has thus far selected either the midpoint or the upper midpoint to be the base ROE applicable to multiple transmission owners, there is no Commission policy mandating the choice of the upper midpoint following a decision to choose a point above the midpoint or median.[551] Joint Customer Intervenors note that the Commission has chosen a point other than the midpoint or upper midpoint.[552] Joint Customer Intervenors

[550] Initial Decision, 153 FERC ¶ 63,027 at PP 118-119, 491.

[551] Joint Customer Intervenors Brief on Exceptions at 50-51 (citing Initial Decision, 153 FERC ¶ 63,027 at P 118).

[552] *Id.* at 51 (citing *Sw. Pub. Serv. Co.*, Opinion No. 421, 83 FERC ¶ 61,138, at 61,637-38 (1998)).

argue that, even if the Commission had never chosen a point other than the midpoint or upper midpoint, the Commission has never declared that only those two points may be considered and, therefore, other points could be considered.[553]

268. OMS states that, should the Commission find that anomalous market conditions existed during the study period, the Commission need not (and should not) default to placing the Base ROE at the upper midpoint. OMS states that the Commission's charge in cases such as this is to set the new Base ROE at a level sufficient for MISO TOs to attract capital on reasonable terms, but no higher, and that to comply with that mandate, the Commission must have the flexibility to set the Base ROE anywhere between the DCF midpoint and the upper midpoint. OMS notes that, in Opinion No. 531-B, the Commission rejected a proposal to allow a Base ROE at the 75th percentile of the zone of reasonableness on the grounds that Commission precedent supported use of the "central tendency" to determine an appropriate return in cases involving the placement of the Base ROE for a region-wide group of utilities.[554] OMS states that Opinion No. 531-B also rejected arguments that Commission precedent requires the Commission to consider distribution of results within the proxy group when determining where in the upper half of the zone the Base ROE should be placed.[555]

269. OMS contends that the Presiding Judge only evaluated the alternative benchmarks to determine if a higher ROE should be used than the midpoint. OMS argues that the Presiding Judge erred by finding irrelevant the relationship between the ROE values from the alternative benchmarks and the upper midpoint, which would support a value lower than the upper midpoint. [556]

270. OMS argues that the Commission should not bind itself to an "either-or" choice between the DCF midpoint and the Upper Midpoint; rather, it must be able to set the Base ROE at other points of central tendency within the upper-half of the zone of reasonableness, such as the mean or the median of the upper-half of the zone. OMS states that the Commission could also set the Base ROE at any point of central tendency within a range between the midpoint of the DCF zone of reasonableness and the Upper Midpoint (i.e. between 9.29 percent and 10.32 percent). OMS argues that the

[553] *Id.*

[554] OMS Brief on Exceptions at 28 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 55).

[555] *Id.* (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 55).

[556] *Id.* at 9.

Commission should take care to preserve maximum flexibility in establishing the new base ROE for MISO TOs, and reject the notion that it is limited to a binary choice between the DCF midpoint and the upper midpoint, where capital market conditions have been proven "anomalous."[557]

271. Complainants contend that the Initial Decision erred in failing to consider their proposed four quartile approach for placement of the ROE.[558] Complainants state that, even though the Commission typically considers the midpoint to be the best embodiment of the central tendency within the zone of reasonableness for the base ROE for multiple utilities, the Commission has expressed concern that this approach gives undue weight to the two extreme values in that range.[559] Complainants state that, to mitigate this shortcoming, Mr. Gorman separated the DCF estimates within his original zone of reasonableness (i.e., 6.75 to 11.01 percent) into four quartiles and redefined the upper and lower bounds of the zone by using the medians of the upper and lower quartiles, resulting in a zone of reasonableness from 8.60 to 9.56 percent. Mr. Gorman then recommended a base ROE situated at the 9.08 percent midpoint between these outer bounds, which he recommended for MISO TOs that have common equity ratios of 55 percent or less.[560] Complainants contend that this approach is appropriate because of the distortive effect of the extreme values, as demonstrated by the effect of their removal.[561]

c. <u>Briefs Opposing Exceptions</u>

272. MISO TOs argue that the placement of the new base ROE at the upper half midpoint is consistent with Opinion No. 531 and produces reasonable results supported by alternative benchmarks and state ROEs.[562] In support of this argument, MISO TOs

[557] *Id.* at 29.

[558] Complainants Brief on Exceptions at 23 (citing Complainants Initial Brief at 40-43; *see also* Complainants Reply Brief at 28-29).

[559] *Id*. (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 144 (citing *S. Cal. Edison Co*., 131 FERC ¶ 61,020, at P 91 (2010), *remanded on other grounds sub. nom. S. Cal. Edison Co. v. FERC*, 717 F.3d. 177 (D.C. Cir. Ct. 2013) and *S. Cal. Edison Co*., 131 FERC ¶ 61,020 at P 86 (citing *Northwest Pipeline Corp.,* 99 FERC ¶ 61,305 at 62,276 (2002)).

[560] *Id*. at 24 (citing Ex. JC-1, pp. 33-37; *see also* Ex. JC-22, pp. 18-19).

[561] *Id*. at 24-25.

[562] MISO TOs Brief Opposing Exceptions at 19.

argue that nothing in Opinion Nos. 531 or 531-B requires the Presiding Judge to calibrate the precise increment by which the DCF midpoint is affected by anomalous capital market conditions and such "exactitude is neither practical nor necessary to satisfy" the FPA.[563] MISO TOs note that the Presiding Judge relied on Opinion No. 531 to inform his zonal placement because this precedent represents the Commission's "most current explication of its approach to zonal placement," and the issues decided in Opinion No. 531 "were substantively identical" to the questions at issue here.[564]

273. MISO TOs argue that, while in deviating from midpoint values in the past, the Commission has typically relied upon comparative risk assessment, this fact does not preclude consideration of ROE adjustments based on other factors, including demonstrated infirmities in DCF inputs and results.[565] MISO TOs also argue that there is no requirement that the Presiding Judge examine every conceivable zonal point within the DCF range or quantify the exact basis-point impact of the documented capital market anomalies. They further argue that the upper-half midpoint is "consistent with the Commission's preference for the central tendency."[566]

274. MISO TOs also state that the Presiding Judge did not need to explicate his reasons for not adopting Complainants' quartile approach, because such approach is "arbitrary and contrived merely to constrict the zone of reasonableness."[567] Additionally, they state that Mr. Gorman articulated the rationale for his proposal and the Presiding Judge rightly rejected this approach.[568]

d. Commission Determination

275. In the Initial Decision, the Presiding Judge determined that, consistent with Commission precedent, in the presence of anomalous capital market conditions, the base ROE should be established at the upper midpoint of the zone of reasonableness. The Presiding Judge stated that, when determining the base ROE applicable to multiple

[563] *Id.* at 20.

[564] *Id.* at 21.

[565] *Id.* at 21.

[566] *Id.* at 22 (citing Initial Decision at P 118).

[567] *Id.* n.50.

[568] MISO TOs Brief Opposing Exceptions at n.50.

transmission owners, "the only two places within the zone of reasonableness that have thus far proved consistent with the Commission's preference of the central tendency" are the midpoint and upper midpoint, which the Presiding Judge determined to be 9.29 percent and 10.32 percent, respectively.[569] In this proceeding, we adopt the Presiding Judge's finding that the upper midpoint of the zone of reasonableness represents the just and reasonable base ROE for the MISO transmission owners.

276. We are unpersuaded by contentions that, if the Commission concludes that MISO TOs' base ROE should be set above the midpoint of the zone of reasonableness, the base ROE should be placed at the true 75th percentile of the zone of reasonableness, rather than at the 10.32 percent midpoint of the upper half of the zone. As the Commission explained in Opinion No. 531-B,[570] the Commission has traditionally used measures of central tendency to determine an appropriate return in ROE cases and, in cases involving the placement of the base ROE above the central tendency of the zone of reasonableness, the Commission has used the central tendency of the top half of the zone. Our decision to utilize the midpoint of the upper half of the zone is based on the record evidence in this proceeding and is consistent with the Commission's established policy of using the midpoint of the ROEs in a proxy group when establishing a central tendency for a region-wide group of utilities.[571]

277. We also disagree with the assertion that there is no evidence to support the specific upward adjustment. Such exactitude has never been required in determining the appropriate placement of ROEs within the zone of reasonableness or for determining the appropriate size of incentives. The Commission maintains discretion to use its judgment in weighing factors specific to a given proceeding to determine where within the zone of reasonableness the final base ROE should be placed.

278. The Commission has held that the midpoint is the appropriate measure of the central tendency for groups of utilities.[572] That determination is not altered by the use of the midpoint of the upper half of the zone of reasonableness.

[569] Initial Decision, 153 FERC ¶ 63,027 at P 118.

[570] Opinion No 531-B, 150 FERC ¶ 61,165 at P 55.

[571] *SoCal Edison*, 131 FERC ¶ 61,020 at P 92, *aff'd in relevant part, S. Cal. Edison Co. v. FERC*, 717 F.3d at 185-87.

[572] *See, e.g.*, S. *Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 91.

279. In response to Joint Customer Intervenors, while anomalous market conditions reduce the Commission's confidence in the establishment of the ROE at the midpoint of the zone of reasonableness, the Commission has not required a precise correlative relationship between a particular ROE and a desired level of transmission investment. Additionally, while we disagree with Complainants' proposed quartile approach, we also find that Joint Customer Intervenors failed to convince us that the 75th percentile of the zone of reasonableness reflects the appropriate base ROE here.

280. We disagree with OMS' argument that the Presiding Judge erred in not considering that the alternative benchmarks indicate that the ROE should be lower than the upper midpoint. MISO TOs' risk premium and expected earnings analyses, which the Commission accepts as discussed above, featured respective midpoint ROEs of 10.36 and 11.99 percent, both of which *exceed* the upper midpoint, indicating that the upper midpoint is not generally higher than the ROEs produced by the alternative benchmarks.

281. Finally, we reject the Complainants' proposal to set MISO TOs' ROE at 9.08 percent based on their four quartile approach. A base ROE of 9.08 percent would be below the 9.29 percent midpoint of the DCF zone of reasonableness in this case. The Complaints' proposal is thus contrary to our holding above that MISO TOs' ROE should be set at a point above the midpoint of the zone of reasonableness.

D. Other Issues

1. Capital Structure

a. Initial Decision

282. At hearing, Complainants and JCA both propose that whatever base ROEs are approved in this proceeding be reduced for all MISO TOs with equity ratios of 55 percent or higher. Mr. Gorman contends that the base ROEs of these utilities should be lowered by 20 basis points.[573] Mr. Hill recommends that the allowed base ROEs of MISO TOs that have common equity ratios of 55 percent or above should be adjusted downward five basis points for every one percent difference between the ratemaking common equity ratio and 49 percent (the average common equity ratio of what he refers to as "the electric utility sample group"). Conversely, he recommends that the base ROEs of firms with equity ratios at or below 45 percent should be adjusted upward five basis points for every one percent difference between the ratemaking common equity ratio and 49 percent.[574]

[573] Exh. JC-1 at 36:13-17.

[574] Exh. JCA-1 at 43:27–44:9; Exh. JCA-11 at 63-64.

Both Complainants/Joint Consumer Advocates contended that a utility with a higher equity ratio is less risky than comparable utilities with lower equity ratios, and that its base ROE should be lowered to reflect that rate differential.[575]

283. The Presiding Judge rejected proposals to adjust MISO TOs' base ROE based on their equity ratios. The Presiding Judge determined that these arguments amounted to a collateral attack on the Commission's rejection in the Hearing Order of an argument that it should cap MISO TOs' actual or hypothetical capital structure at 50 percent equity. The Presiding Judge concluded that lowering the base ROE for utilities with an equity ratio greater than 50 percent would "do indirectly what the Commission said it would not do directly."[576] The Presiding Judge further noted that the Commission's approach to setting the base ROE already incorporates measures of the utilities' risk, obviating the need to account for the effect of capital structure on risk.

b. Briefs on Exceptions

284. Complainants argue that the Presiding Judge erred in rejecting Complainants' recommended capital structure-based ROE adjustments as a collateral attack on the Hearing Order. Complainants argue that the Hearing Order did not foreclose consideration of all issues related to MISO TOs' capital structure for evaluating the base ROE such that their argument warrants consideration.[577] Specifically, the Commission found that issues regarding capital structures "are best addressed with respect to that ROE, which the Commission is setting for hearing."[578] Complainants state that an equity-heavy capital structure increases costs to ratepayers and recommends a 20 basis point reduction to the base ROE of MISO TOs whose common equity structure exceeds 55 percent to account for their lower risk.[579]

[575] Exh. JC-1 at 20-21; Exh. JCA-11 at 45.

[576] Initial Decision, 153 FERC ¶ 63,027 at P 483.

[577] Complainants Brief on Exceptions at 51.

[578] *Id.* at 51-52 (citing Hearing Order, 149 FERC ¶ 61,049 at P 199).

[579] Complainants Brief on Exceptions at 52 (citing Complainants Initial Brief at 90; *see also* Complainants Reply Brief at 39-41).

c. Briefs Opposing Exceptions

285. MISO TOs also argue that the Presiding Judge correctly rejected Complainants' collateral attack on the Hearing Order's rejection of a cap on common equity ratios.[580]

d. Commission Determination

286. We disagree with Complainants' argument that the Commission should reduce the base ROEs of utilities with capital structures featuring at least 55 percent equity by 20 basis points. Although this proposal is not beyond the scope of this proceeding, as it is distinct from Complainants' request to prohibit equity-rich capital structures, it is insufficiently supported and inconsistent with the Commission's methodology for determining where in the DCF zone of reasonableness to place a specific public utility. While the Commission has indeed adjusted a company's base ROE above or below the central tendency of the zone of reasonableness based on the relative risk analysis,[581] it does so only after a full evaluation of all relevant factors including both business and financial risk.[582] This is because lower financial risk may be offset by higher business risk or vice versa. Complainants have provided no such complete evaluation of any of the MISO TOs' relative risk versus the proxy group. Rather, they seek a risk adjustment based upon a single factor, an alleged equity-rich capital structure, without consideration of any other risk factor. This is contrary to Commission policy.

287. Moreover, although equity-rich capital structures may reduce utility risk Complainants have not attempted to justify or provide quantitative support for presumably arbitrary 55 percent threshold for this penalty. Additionally, Complainants' observation that their proposed 20 basis-point reduction is approximately one third of the difference between the spread between A and Baa utility bond yields for the six months ending December 2014,[583] lacks quantitative support such that it does not make the

[580] MISO TOs Brief Opposing Exceptions at 49-51.

[581] *See, e.g.*, *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d at 57 ("Once the Commission has defined a zone of reasonableness [using the DCF model], it then assigns the pipeline a rate within that range to reflect specific investment risks associated with that pipeline as compared to the proxy group companies").

[582] *See, e.g.*, *El Paso Natural Gas Co.*, Opinion No. 528-A, 154 FERC ¶ 61,120 at PP 302-340 (2016) (Opinion No. 528-A).

[583] *See* Exh. MTO-1 at 36.

choice of this threshold any less arbitrary. Complainants provide no evidence of how much a higher return correlates with a higher credit rating. Complainants also do not justify why their proposed ROE reduction should apply to all utilities with equity percentages above 55 percent, regardless of what the equity percentage is.

288. In any event, Complainants' position fails to take into account the fact that our criteria for selecting members of the proxy group are intended to produce a proxy group made up of companies of similar risk. Those criteria include screens to ensure that the proxy group contains only utilities with similar credit ratings to the utility at issue. To the extent that a higher percentage equity in the capital structure reduces a utility's risk, as Complainants and Joint Consumer Advocates assert, then the utility's credit rating would be correspondingly higher than that of a utility with a typical capital structure. The resulting higher credit ratings of members of the proxy group would reduce the calculated ROE, because higher-rated companies generally have lower ROEs. Consequently, additional reductions to the ROEs that are proposed by Complainants essentially reduce the ROE twice for featuring equity-rich capital structures.

289. Furthermore, as a policy matter, the Commission does not directly incentivize utilities' to adjust their preferred capital structures. The Commission has not previously directly encouraged utilities to feature more debt in their capital structure. We find that it would be inappropriate to encourage additional debt leveraging of utilities, many of which are undertaking large investments or do not have high credit ratings.

2. <u>Formula Rate ROE Adjustments</u>

a. <u>Initial Decision</u>

290. The Presiding Judge rejected the arguments of Joint Consumer Advocates and Joint Customer Intervenors that MISO TOs' formula rates reduce their business risks, at least relative to state-regulated utilities. The Presiding Judge observed that, although the parties appeared to "agree that formula rates reduce the risk of under-recovery, but deny the utility the benefits of over-recover[y]," the record did not indicate which effect was likely to predominate, making it impossible to determine the net effect of formula rates on a company's risk profile.[584] The Presiding Judge also concluded that the record did not contain evidence that the formula rates gave MISO TOs a significant advantage in more rapidly recovering their costs relative to state-regulated electric utilities.[585] In addition, the Presiding Judge distinguished a series of earlier Commission cases, in which

[584] Initial Decision, 153 FERC ¶ 63,027 at P 419.

[585] *Id.* PP 429-430, 432.

the Commission appeared to adopt the proposition that formula rates reduced a utility's business risk. The Presiding Judge explained that those cases involved generators that had contracted to sell electricity to corporate affiliates that agreed to purchase all of the generators' output and the generator had a formula rate that provided for the recovery of all its expenses — circumstances that the Presiding Judge determined were not present for MISO TOs.[586] Finally, the Presiding Judge also noted that "a formula rate . . . appears to best serve the public interest" and, therefore, that lowering a public utility's ROE on the basis that it receives a formula rate could run counter to Commission objectives.[587]

b. Briefs on Exceptions

291. Joint Customer Intervenors assert that the Presiding Judge failed to consider evidence demonstrating that the formula rate-based transmission service at issue here is less risky than the integrated generation and distribution service regulated by the state commissions.[588] OMS states that the Commission has explained that, in determining the ROE for public utilities, its evaluation of investment focuses on the two major sources of uncertainty to a company: the business risk and financial risk. OMS reiterates the arguments that Attachment O to the MISO Tariff – a comprehensive formula rate transmission rate – substantially mitigates the business risk faced by MISO TOs, and that this reduction in risk must be considered and given effect in determining a just and reasonable ROE for MISO TOs.[589] OMS states that the Presiding Judge rejected those arguments, citing three reasons why the availability of formula rates should not be a factor in the ROE determination. OMS contends that each of the three reasons relied upon by the Presiding Judge is erroneous.

292. First, OMS states that the Presiding Judge appears to have adopted MISO TOs' contention that formula rates are a double-edge sword; they eliminate the need for utilities to file rate cases when costs are increasing, but do not eliminate the risk of retroactive downward adjustments to rates when the formula has operated to over-recover costs.[590] OMS states that the inability to enjoy a windfall when costs are declining is not

[586] *Id.* PP 435-443.

[587] *Id.* PP 449-450.

[588] Joint Customer Intervenors Brief on Exceptions at 47-48 (citing Exh. JCI-4 at 32:21-36:2).

[589] OMS Brief on Exceptions at 44 citing OMS Initial Brief at 34-35.

[590] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 446).

a factor that should be thought to balance out the mitigation of business risk formula rates provide in an increasing-cost environment.

293. Second, OMS states that the Presiding Judge found that formula rates serve the "public interest" because they ensure that a utility earns no more or less than its authorized Base ROE.[591] OMS states that this interest would be adversely affected, according to the Presiding Judge, if base ROEs were reduced to reflect the lower business risk faced by a company with a formula rate.[592] OMS argues that the Initial Decision's finding in this regard misses the point that was argued by OMS and others because it focuses on the pros and cons of formula rates from the point of view of utilities, not from the perspective of investors. OMS states that investors care more about the certainty of cost recovery over time than they do about the opportunity for short-term windfalls, and therefore investors require less of a return from companies that offer a certainty of cost recovery than they do from companies offering instead the remote chance for an occasional windfall.[593] OMS contends that, by failing to give effect to this fact, the Presiding Judge confers a Base ROE that is higher than the actual risk-adjusted cost of equity for companies with full-cost recovery formula rates.

294. Finally, OMS states that the Presiding Judge relies on the fact that "the Commission has recently ignored without comment contentions that it should reduce a utility's Base ROE based on its utilization of allegedly less risky formula rates."[594] OMS argues that the Commission's silence in *PATH* cannot be construed as a determination on the merits of the question, and the Commission made clear in a more recent incarnation of the *PATH* proceedings that "silence is not evidence of Commission policy."[595] Furthermore, OMS contends that in *PATH* and the other orders to which the Initial

[591] *Id.* at 45 (citing Initial Decision, 153 FERC ¶ 63,027 at P 447).

[592] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 448).

[593] *Id.* n.155 ("It is well-established in the financial literature that investors are generally 'risk-averse.' This means that the required return for an investment that has symmetric expectations of gains and losses is greater than the required return for an investment with certainty of no gains or losses.").

[594] *Id.* at 46 (citing Initial Decision, 153 FERC ¶ 63,027 at P 445 (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008) (*PATH*))).

[595] *Id.* (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 153 FERC ¶ 61,308, at P 13 (2015)).

Decision alludes[596] (save one), the Commission declined to expressly recognize the risk-mitigating effects of formula rates in the context of considering ROE *incentives*, not in the context of determining a just and reasonable, properly risk-adjusted *base* ROE. That the Commission did not expressly give effect to the risk-mitigating impact of formula rates in ROE adder cases, according to OMS, says nothing about the ability of formula rates to mitigate the risks that are relevant in Base ROE cases. OMS states that the only case cited by the Presiding Judge that specifically addressed a utility's base ROE is *Virginia Electric & Power Company*, where the Commission reduced the requested base ROE without expressly addressing, one way or the other, the argument that formula rates mitigate risks.[597] OMS asserts that since silence is not evidence of Commission policy, the Initial Decision's reliance on these orders is not well-founded.

c. **Briefs Opposing Exceptions**

295. MISO TOs state that the Commission has previously found that formula rate tariffs do not fully mitigate the cost recovery risk of federally-regulated transmission or render public utilities less risky than state-regulated enterprises.[598]

296. In support of this argument, they state that the Commission has previously found that formula rate tariffs do not fully mitigate the cost recovery risk of federally-regulated transmission or render public utilities less risky than state-regulated enterprises.[599] Additionally, in response to OMS's argument that the Presiding Judge wrongly discounted Mr. Hill's comparable risk evidence, MISO TOs claim that OMS documented no errors in the Presiding Judge's finding that such evidence was outdated, inapplicable, incomplete, or inconsistent with testimony offered by other witnesses.[600] MISO TOs also argue that the Presiding Judge rightly determined that Mr. Solomon's testimony was incomplete, tangentially relevant, or not supportive of Mr. Solomon's position.[601]

[596] *Id.* at 46 (citing Initial Decision, 153 FERC ¶ 63,027 at n.570).

[597] *Id.* at 46-47 citing *Virginia Elec. & Power Co.*, 123 FERC ¶ 61,098, at P 58 (2008).

[598] MISO TOs Brief Opposing Exceptions at 35.

[599] *Id.*

[600] *Id.* at 35-36.

[601] *Id.* at 36.

d. Commission Determination

297. We affirm the Presiding Judge's determination that the use of formula rates does not warrant a lower base ROE. To the extent that formula rates reduce risk, they would, similar to the use of more equity in the capital structure, improve utility credit ratings. This would in turn affect the DCF proxy group based on screens requiring a group of similarly-rated utilities, diminishing the ROE produced by the DCF analysis. Additionally, nearly all electric utilities feature transmission formula rates. Consequently, the use of such formula rates is reflected in the proxy group within the DCF analysis.

298. Finally, as the Commission previously explained in Opinion No. 531, "when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology," which in this case, would be 11.35 percent.[602] We therefore find that MISO TOs' total or maximum ROE, including transmission incentive ROE adders, cannot exceed 11.35 percent.[603]

The Commission orders:

(A) MISO TOs' base ROE is hereby set at 10.32 percent with a total or maximum ROE including incentives not to exceed 11.35 percent, effective on the date of this order, as discussed in the body of this order.

(B) MISO and MISO TOs are hereby directed to submit compliance filings with revised rates to be effective the date of this order reflecting a 10.32 percent base ROE and a total or maximum ROE not exceeding 11.35 percent (inclusive of transmission incentive ROE adders), within thirty (30) days of the date of this order, as discussed in the body of this order.

(C) MISO and MISO TOs are hereby directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2016), within thirty (30) days of the date of this order, for the 15-month refund period from November 13, 2013 through February 11, 2015, as discussed in the body of this order.

(D) MISO and MISO TOs are hereby directed to file a refund report

[602] Opinion No. 531, 147 FERC ¶ 61,234 at P 165.

[603] *See* Opinion No. 531-A, 149 FERC ¶ 61,032 at P 11.

detailing the principal amounts plus interest paid to each of their customers within forty-five (45) days of the date of this order.

By the Commission. Commissioner Honorable is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Federal Reserve Bank of New York
Staff Reports

The Equity Risk Premium: A Review of Models

Fernando Duarte
Carlo Rosa

Staff Report No. 714
February 2015

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Abstract

We estimate the equity risk premium (ERP) by combining information from twenty models. The ERP in 2012 and 2013 reached heightened levels—of around 12 percent—not seen since the 1970s. We conclude that the high ERP was caused by unusually low Treasury yields.

Key words: equity premium, stock returns

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1. Introduction

The equity risk premium —the expected return on stocks in excess of the risk-free rate— is a fundamental quantity in all of asset pricing, both for theoretical and practical reasons. It is a key measure of aggregate risk-aversion and an important determinant of the cost of capital for corporations, savings decisions of individuals and budgeting plans for governments. Recently, the equity risk premium (ERP) has also returned to the forefront as a leading indicator of the evolution of the economy, a potential explanation for jobless recoveries and a gauge of financial stability[3].

In this article, we estimate the ERP by combining information from twenty prominent models used by practitioners and featured in the academic literature. Our main finding is that the ERP has reached heightened levels. The first principal component of all models –a linear combination that explains as much of the variance of the underlying data as possible– places the one-year-ahead ERP in June 2012 at 12.2 percent, above the 10.5 percent that was reached during the financial crisis in 2009 and at levels similar to those in the mid and late 1970s. Since June 2012 and until the end of our sample in June 2013, the ERP has remained little changed, despite substantial positive realized returns. It is worth keeping in mind, however, that there is considerable uncertainty around these estimates. In fact, the issue of whether stock returns are predictable is still an active area of research.[4] Nevertheless, we find that the dispersion in estimates across models, while quite large, has been shrinking, potentially signaling increased agreement

[3] As an indicator of future activity, a high ERP at short horizons tends to be followed by higher GDP growth, higher inflation and lower unemployment. See, for example, Piazzesi and Schneider (2007), Stock and Watson (2003), and Damodaran (2012). Bloom (2009) and Duarte, Kogan and Livdan (2013) study connections between the ERP and real aggregate investment. As a potential explanation of the jobless recovery, Hall (2014) and Kuehn, Petrosky-Nadeau and Zhang (2012) propose that increased risk-aversion has prevented firms from hiring as much as would be expected in the post-crisis macroeconomic environment. Among many others, Adrian, Covitz and Liang (2013) analyze the role of equity and other asset prices in monitoring financial stability.
[4] A few important references among a vast literature are Ang and Bekaert (2007), Goyal and Welch (2008), Campbell and Thompson (2008), Kelly and Pruitt (2013), Chen, Da and Zhao (2013), Neely, Rapach, Tu and Zhou (2014).

even when the models are substantially different from each other and use more than one hundred different economic variables.

In addition to estimating the level of the ERP, we investigate the reasons behind its recent behavior. Because the ERP is the difference between expected stock returns and the risk-free rate, a high estimate can be due to expected stock returns being high or risk-free rates being low. We conclude the ERP is high because Treasury yields are unusually low. Current and expected future dividend and earnings growth play a smaller role. In fact, expected stock returns are close to their long-run mean. One implication of a bond-yield-driven ERP is that traditional indicators of the ERP like the price-dividend or price-earnings ratios, which do not use data from the term structure of risk-free rates, may not be as good a guide to future excess returns as they have been in the past.

As a second contribution, we present a concise and coherent taxonomy of ERP models. We categorize the twenty models into five groups: predictors that use historical mean returns only, dividend-discount models, cross-sectional regressions, time-series regressions and surveys. We explain the methodological and practical differences among these classes of models, including the assumptions and data sources that each require.

2. The Equity Risk Premium: Definition

Conceptually, the ERP is the compensation investors require to make them indifferent at the margin between holding the risky market portfolio and a risk-free bond. Because this compensation depends on the future performance of stocks, the ERP incorporates expectations of future stock market returns, which are not directly observable. At the end of the day, any model of the ERP is a model of investor expectations. One challenge in estimating the ERP is that it is not clear what truly constitutes the market return and the risk-free rate in the real world. In practice, the most common measures of total market returns are based on broad stock market indices, such as the S&P 500 or the Dow Jones Industrial

Average, but those indices do not include the whole universe of traded stocks and miss several other components of wealth such as housing, private equity and non-tradable human capital. Even if we restricted ourselves to all traded stocks, we still have several choices to make, such as whether to use value or equal-weighted indices, and whether to exclude penny or infrequently traded stocks. A similar problem arises with the risk-free rate. While we almost always use Treasury yields as measures of risk-free rates, they are not completely riskless since nominal Treasuries are exposed to inflation[5] and liquidity risks even if we were to assume there is no prospect of outright default. In this paper, we want to focus on how expectations are estimated in different models, and not on measurement issues regarding market returns and the risk-free rate. Thus, we follow common practice and always use the S&P 500 as a measure of stock market prices and either nominal or real Treasury yields as risk-free rates so that our models are comparable with each other and with most of the literature.

While implementing the concept of the ERP in practice has its challenges, we can precisely define the ERP mathematically. First, we decompose stock returns[6] into an expected component and a random component:

$$R_{t+k} = E_t[R_{t+k}] + error_{t+k}. \tag{1}$$

In equation (1), R_{t+k} are *realized* returns between *t* and *t*+*k*, and $E_t[R_{t+k}]$ are the returns that were expected from *t* to $t+k$ using information available at time t. The variable $error_{t+k}$ is a random variable that is unknown at time t and realized at $t+k$. Under rational expectations, $error_{t+k}$ has a mean of zero and is orthogonal to $E_t[R_{t+k}]$. We keep the discussion as general as possible and do not assume rational

[5] Note that inflation risk in an otherwise risk-free nominal asset does not invalidate its usefulness to compute the ERP. If stock returns and the risk-free rate are expressed in nominal terms, their difference has little or no inflation risk. This follows from the following formula, which holds exactly in continuous time and to a first order approximation in discrete time: real stock returns – real risk-free rate = (nominal stock returns – expected inflation) – (nominal risk-free rate – expected inflation) = nominal stock returns– nominal risk-free rate. Hence, there is no distinction between a nominal and a real ERP.
[6] Throughout this article, all returns are *net* returns. For example, a five percent return corresponds to a net return of 0.05 as opposed to a *gross* return of 1.05.

expectations at this stage, although it will be a feature of many of the models we consider. The ERP at time t for horizon k is defined as

$$ERP_t(k) = E_t[R_{t+k}] - R^f_{t+k}, \tag{2}$$

where R^f_{t+k} is the risk-free rate for investing from t to $t + k$ (which, being risk-free, is known at time t).

This definition shows three important aspects of the ERP. First, future expected returns and the future ERP are stochastic, since expectations depend on the arrival of new information that has a random component not known in advance[7]. Second, the ERP has an investment horizon k embedded in it, since we can consider expected excess returns over, say, one month, one year or five years from today. If we fix t, and let k vary, we trace the *term structure* of the equity risk premium. Third, if expectations are rational, because the unexpected component $error_{t+k}$ is stochastic and orthogonal to expected returns, the ERP is always less volatile than realized excess returns. In this case, we expect ERP estimates to be smoother than realized excess returns.

3. Models of the Equity Risk Premium

We describe twenty models of the equity risk premium, comparing their advantages, disadvantages and ease of implementation. Of course, there are many more models of the ERP than the ones we consider. We selected the models in our study based on the recent academic literature, their widespread use by practitioners and data availability. Table I describes the data we use and their sources, all of which are either readily available or standard in the literature[8]. With a few exceptions, all data is monthly from January 1960 to June 2013. Appendix A provides more details.

[Insert Table I here]

[7] More precisely, $E_t[R_{t+k}]$ and $ERP_t(k)$ are known at time t but random from the perspective of all earlier periods.
[8] In fact, except for data from I/B/E/S and Compustat, all sources are public.

We classify the twenty models into five categories based on their underlying assumptions; models in the same category tend to give similar estimates for the ERP. The five categories are: models based on the historical mean of realized returns, dividend discount models, cross-sectional regressions, time-series regressions and surveys.

All but one of the estimates of the ERP are constructed in real time, so that an investor who lived through the sample would have been able to construct the measures at each point in time using available information only[9]. This helps minimize look-ahead bias and makes any out-of-sample evaluation of the models more meaningful. Clearly, most of the models themselves were designed only recently and were not available to investors in real time, potentially introducing another source of forward-looking and selection biases that are much more difficult to quantify and eliminate.

3.1 Historical mean of realized returns

The easiest approach to estimating the ERP is to use the historical mean of realized market returns in excess of the contemporaneous risk-free rate. This model is very simple and, as shown in Goyal and Welch (2008), quite difficult to improve upon when considering out-of-sample predictability performance measures. The main drawbacks are that it is purely backward looking and assumes that the future will behave like the past, i.e. it assumes the mean of excess returns is either constant or very slow moving over time, giving very little time-variation in the ERP. The main choice is how far back into the past we should go when computing the historical mean. Table II shows the two versions of historical mean models that we use.

[Insert Table II here]

[9] The one exception is Adrian, Crump and Moench's (2014) cross-sectional model, which is constructed using full-sample regression estimates.

3.2 Dividend discount models (DDM)

All DDM start with the basic intuition that the value of a stock is determined by no more and no less than the cash flows it produces for its shareholders, as in Gordon (1962). Today's stock price should then be the sum of all expected future cash flows, discounted at an appropriate rate to take into account their riskiness and the time value of money. The formula that reflects this intuition is

$$P_t = \frac{D_t}{\rho_t} + \frac{E_t[D_{t+1}]}{\rho_{t+1}} + \frac{E_t[D_{t+2}]}{\rho_{t+2}} + \frac{E_t[D_{t+3}]}{\rho_{t+3}} + \cdots, \tag{3}$$

where P_t is the current price of the stock, D_t are current cash flows, $E_t[D_{t+k}]$ are the cash flows k periods from now expected as of time t, and ρ_{t+k} is the discount rate for time $t + k$ from the perspective of time t. Cash flows to stockholders certainly include dividends, but can also arise from spin-offs, buy-outs, mergers, buy-backs, etc. In general, the literature focuses on dividend distributions because they are readily available data-wise and account for the vast majority of cash flows. The discount rate can be decomposed into

$$\rho_{t+k} = 1 + R^f_{t+k} + ERP_t(k). \tag{4}$$

In this framework, the risk-free rate captures the discounting associated with the time value of money and the ERP captures the discounting associated with the riskiness of dividends. When using a DDM, we refer to $ERP_t(k)$ as the *implied* ERP. The reason is that we plug in prices, risk-free rates and estimated expected future dividends into equation (3), and then derive what value of $ERP_t(k)$ makes the right-hand side equal to the left-hand side in the equation, i.e. what ERP value is *implied* by equation (3).

DDM are forward looking and are consistent with no arbitrage. In fact, equation (3) must hold in any economy with no arbitrage[10]. Another advantage of DDM is that they are easy to implement. A drawback of DDM is that the results are sensitive to how we compute expectations of future dividends. Table III displays the DDM we consider and a brief description of their different assumptions.

[Insert Table III here]

3.3 Cross-sectional regressions

This method exploits the variation in returns and exposures to the S&P 500 of different assets to infer the ERP[11]. Intuitively, cross-sectional regressions find the ERP by answering the following question: what is the level of the ERP that makes expected returns on a variety of stocks consistent with their exposure to the S&P 500? Because we need to explain the relationship between returns and exposures for multiple stocks with a single value for the ERP (and perhaps a small number of other variables), this model imposes tight restrictions on estimates of the ERP.

The first step is to find the exposures of assets to the S&P 500 by estimating an equation of the following form:

$$R_{t+k}^{i} - R_{t+k}^{f} = \alpha^{i} \times state\ variables_{t+k} + \beta^{i} \times risk\ factors_{t+k} + idiosyncratic\ risk_{t+k}^{i}. \quad (5)$$

In equation (5), R_{t+k}^{i} is the realized return on a stock or portfolio i from time t to $t+k$. $State\ variables_{t+k}$ are any economic indicators that help identify the state of the economy and its likely future path. $Risk\ factors_{t+k}$ are any measures of systematic contemporaneous co-variation in returns across all stocks or portfolios. Of course, some economic indicators can be both state variables and risk

[10] Note that when performing the infinite summation in equation (3) we have not assumed the n^{th} term goes to zero as n tends to infinity, which allows for rational bubbles. In this sense, DDM do allow for a specific kind of bubble.
[11] See Polk, Thompson and Vuolteenaho (2006) and Adrian, Crump and Moench (2014) for a detailed description of this method.

factors at the same time. Finally, $idiosyncratic\ risk_{t+k}^{i}$ is the component of returns that is particular to each individual stock or portfolio that is not explained by $state\ variables_{t+k}$ or $risk\ factors_{t+k}$ (both of which, importantly, are common to all stocks and hence not indexed by i). Examples of state variables are inflation, unemployment, the yield spread between Aaa and Baa bonds, the yield spread between short and long term Treasuries, and the S&P 500's dividend-to-price ratio. The most important risk factor is the excess return on the S&P 500, which we must include if we want to infer the ERP consistent with the cross-section of stock returns. Other risk-factors usually used are the Fama-French (1992) factors and the momentum factor of Carhart (1997). The values in the vector α^{i} give the strength of asset-specific return predictability and the values in the vector β^{i} give the asset-specific exposures to risk factors[12]. For the cross-section of assets indexed by i, we can use the whole universe of traded stocks, a subset of them, or portfolios of stocks grouped, for example, by industry, size, book-to-market, or recent performance. It is important to point out that equation (5) is not a predictive regression; the left and right-hand side variables are both associated with time $t + k$.

The second step is to find the ERP associated with the S&P 500 by estimating the cross-sectional equations

$$R_{t+k}^{i} - R_{t+k}^{f} = \lambda_t(k) \times \hat{\beta}^{i}\ , \qquad (6)$$

where $\hat{\beta}^{i}$ are the values found when estimating equation (5). Equation (6) attempts to find, at each point in time, the vector of numbers $\lambda_t(k)$ that makes exposures β^{i} as consistent as possible with realized excess returns of all stocks or portfolios considered. The element in the vector $\hat{\lambda}_t(k)$ that is multiplied by

[12] The vectors α^{i} and β^{i} could also be time-varying, reflecting a more dynamic relation between returns and their explanatory variables. In this case, the estimation of equation (5) is more complicated and requires making further assumptions. The model by Adrian, Crump and Moench (2014) is the only cross-sectional model we examine that uses time-varying α^{i} and β^{i} .

the element in the $\hat{\beta}^i$ vector corresponding to the S&P 500 is $ERP_t(k)$, the equity risk premium we are seeking.

One advantage of cross-sectional regressions is that they use information from more asset prices than other models. Cross-sectional regressions also have sound theoretical foundations, since they provide one way to implement Merton's (1973) Intertemporal Capital Asset Pricing Model. Finally, this method nests many of the other models considered. The two main drawbacks of this method are that results are dependent on what portfolios, state variables and risk factors are used (Harvey, Liu and Zhu (2014)), and that it is not as easy to implement as most of the other options. Table IV displays the cross-sectional models in our study, together with the state variables and risk factors they use.

[Insert Table IV here]

3.4 Time-series regressions

Time-series regressions use the relationship between economic variables and stock returns to estimate the ERP. The idea is to run a predictive linear regression of realized excess returns on lagged "fundamentals":

$$R_{t+k} - R^f_{t+k} = a + b \times Fundamental_t + error_t. \tag{7}$$

Once estimates $\hat{a}$ and $\hat{b}$ for a and b are obtained, the ERP is obtained by ignoring the error term:

$$ERP_t(k) = \hat{a} + \hat{b} \times Fundamental_t. \tag{8}$$

In other words, we estimate only the forecastable or expected component of excess returns. This method attempts to implement equations (1) and (2) as directly as possible in equations (7) and (8), with the assumption that "fundamentals" are the right sources of information to look at when computing expected returns, and that a linear equation is the correct functional specification.

The use of time-series regressions requires minimal assumptions; there is no concept of equilibrium and no absence of arbitrage necessary for the method to be valid[13]. In addition, implementation is quite simple, since it only involves running ordinary least-square regressions. The challenge is to select what variables to include on the right-hand side of equation (7), since results can change substantially depending on what variables are used to take the role of "fundamentals". In addition, including more than one predictor gives poor out-of-sample predictions even if economic theory may suggest a role for many variables to be used simultaneously (Goyal and Welch (2008)). Finally, time-series regressions ignore information in the cross-section of stock returns. Table V shows the time-series regression models that we study.

[Insert Table V here]

3.5 Surveys

The survey approach consists of asking economic agents about the current level of the ERP. Surveys incorporate the views of many people, some of which are very sophisticated and/or make real investment decisions based on the level of the ERP. Surveys should also be good predictors of excess returns because in principle stock prices are determined by supply and demand of investors such as the ones taking the surveys. On the other hand, Greenwood and Shleifer (2014) document that investor expectations of future stock market returns are positively correlated with past stock returns and with the current level of the stock market, but strongly *negatively* correlated with model-based expected returns and future realized stock market returns. Other studies such as Easton and Sommers (2007) also argue that survey measures of the ERP can be systematically biased. In this paper, we use the survey of CFOs by Graham and Harvey (2012), which to our knowledge is the only large-scale ERP survey that has more than just a few years of data (see Table VI).

[Insert Table VI here]

[13] However, the Arbitrage Pricing Theory of Ross (1976) provides a strong theoretical underpinning for time-series regressions by using no-arbitrage conditions.

4. Estimation of the Equity Risk Premium

We now study the behavior of the twenty models we consider by conducting principal component analysis. Since forecast accuracy can be substantially improved through the combination of multiple forecasts[14], the optimal strategy to forecast excess stock returns may consist of combining together all these models. The first principal component of the twenty models that we use is the linear combination of ERP estimates that captures as much of the variation in the data as possible. The second, third, and successive principal components are the linear combinations of the twenty models that explain as much of the variation of the data as possible and are also uncorrelated to all the preceding principal components. If the first few principal components —say one or two— account for most of the variation of the data, then we can use them as a good summary for the variation in all the measures over time, reducing the dimensionality from twenty to one or two. In addition, in the presence of classical measurement error, the first few principal components can achieve a higher signal-to-noise ratio than other summary measures like the cross-sectional mean of all models (Geiger and Kubin (2013)).

To compute the first principal component, we proceed in three steps. We first de-mean all ERP estimates and find their variance-covariance matrix. In the second step, we find the linear combination that explains as much of the variance of the de-meaned models as possible. The weights in the linear combination are the elements of the eigenvector associated with the largest eigenvalue of the variance-covariance matrix found in the first step. In the third step, we add to the linear combination just obtained, which has mean zero, the average of ERP estimates across all models and all time periods. Under the assumption that each of the models is an unbiased and consistent estimator of the ERP, the average across all models and all time periods is an unbiased and consistent estimator of the unconditional mean of the ERP. The time

[14] See, *inter alia*, Clemen (1989), Diebold and Lopez (1996) and Timmermann (2006).

variation in the first principal component then provides an estimate of the conditional ERP[15]. The share of the variance of the underlying models explained by this principal component is 76 percent, suggesting that there is not too much to gain from examining principal components beyond the first[16].

We now focus on the one-year-ahead ERP estimates and study other horizons in the next section.

The first two columns in Table VII show the mean and standard deviation of each model's estimates. The unconditional mean of the ERP across all models is 5.7 percent, with an average standard deviation of 3.2 percent. DDM give the lowest mean ERP estimates and have moderate standard deviations. In contrast, cross-sectional models tend to have mean ERP estimates on the high end of the distribution and very smooth time-series. Mean ERP estimates for time-series regressions are mixed, with high and low values depending on the predictors used, but uniformly large variances. The survey of CFOs has a mean and standard deviation that are both about half as large as in the overall population of models. The picture that emerges from Table VII is that there is considerable heterogeneity across model types, and even sometimes within model types, thereby underscoring the difficulty inherent in finding precise estimates of the ERP.

[15] As is customary in the literature, we perform the analysis using ERP estimates in levels, even though they are quite persistent. Results in first-differences do not give economically reasonable estimates since they feature a pro-cyclical ERP and unreasonable magnitudes.

One challenge that arises in computing the principal component is when we have missing observations, either because some models can only be obtained at frequencies lower than monthly or because the necessary data is not available for all time periods (Appendix A contains a detailed description of when this happens). To overcome this challenge, we use an iterative linear projection method, which conceptually preserves the idea behind principal components. Let X be the matrix that has observations for different models in its columns and for different time periods in its rows. On the first iteration, we make a guess for the principal component and regress the non-missing elements of each row of X on the guess and a constant. We then find the first principal component of the variance-covariance matrix of the fitted values of these regressions, and use it as the guess for the next iteration. The process ends when the norm of the difference between consecutive estimates is small enough. We thank Richard Crump for suggesting this method and providing the code for its implementation.

[16] The second and third principal components account for 13 and 8 percent of the variance, respectively.

[Insert Table VII here]

Figure 1 shows the time-series for all one-year-ahead ERP model estimates, with each class of models in a different panel. The green lines are the ERP estimates from the twenty underlying models. The black line, reproduced in each of the panels, is the principal component of all twenty models. The shaded areas are NBER recessions. The figure gives a sense of how the time-series move together, and how much they co-vary with the first principal component. Table VIII shows the correlations among models. Figure 1 and Table VIII give the same message: despite some outliers, there is a fairly strong correlation within each of the five classes of models. Across classes, however, correlations are small and even negative. Interestingly, the correlation between some DDM and cross-sectional models is as low as -91 percent. This negative correlation, however, disappears if we look at lower frequencies. When aggregated to quarterly frequency, the smallest correlation between DDM and cross-sectional models is -22 percent, while at the annual frequency it is 12 percent.

[Insert Figure 1 here]

[Insert Table VIII here]

Figure 1 also shows that the first principal component co-varies negatively with historical mean models, but positively with DDM and cross-sectional regression models. Time-series regression models are also positively correlated with the first principal component, although this is not so clearly seen in Panel 4 of Figure 1 because of the high volatility of time-series ERP estimates. The last panel shows that the survey of CFOs does track the first principal component quite well at low frequencies (e.g. annual), although any conclusions about survey estimates should be interpreted with caution given the short length of the sample.

As explained earlier, the first principal component is a linear combination of the twenty underlying ERP models:

$$PC_t^{(1)} = \sum_{m=1}^{20} w^{(m)} ERP_t^{(m)}. \tag{9}$$

In the above equation, m indexes the different models, $PC_t^{(1)}$ is the first principal component, $ERP_t^{(m)}$ is the estimate from model m and $w^{(m)}$ is the weight that the principal component places on model m. The third column in Table VII, labeled "PC coefficients", shows the weights $w^{(m)}$ normalized to sum up to one to facilitate comparison, i.e. the table reports the weights $\widehat{w}^{(m)}$ where

$$\widehat{w}^{(m)} = \frac{w^{(m)}}{\sum_{m=1}^{20} w^{(m)}}. \tag{10}$$

The first principal component puts positive weight on models based on the historical mean, cross-sectional regressions and the survey of CFOs. It weights DDM and time-series regressions mostly negatively. The absolute values of the weights are very similar for many of the models, and there is no single model or class of models that dominates. This means that the first principal component uses information from many of the models.

The last column in Table VII, labeled "Exposure to PC", shows the extent to which models *load* on the first principal component. By construction, each of the twenty ERP models can be written as a linear combination of twenty principal components:

$$ERP_t^{(m)} = \sum_{i=1}^{20} load_i^{(m)} PC_t^{(i)}, \tag{11}$$

where m indexes the model and i indexes the principal components. The values in the last column of Table VII are the loadings on the first principal component ($i = 1$) for each model ($m = 1, 2, \dots, 20$), again normalized to one for ease of comparability:

$$\widehat{load}_1^{(m)} = \frac{load_1^{(m)}}{\sum_{m=1}^{20} load_i^{(m)}}. \tag{12}$$

Most models have a positive loading on the first principal component; whenever the loading is negative, it tends to be relatively small. This means the first principal component, as expected, is a good explanatory variable for most models. Looking at the third and fourth columns of Table VII together, we can obtain additional information. For example, a model with a very high loading (fourth column) accompanied by a very small PC coefficient (third column) is likely to mean that the model is almost redundant, in the sense that it is close to being a linear combination of all other models and does not provide much independent information to the principal component. On the other hand, if the PC coefficient and loading are both high, the corresponding model is likely providing information not contained in other measures.

Figure 2 shows the first principal component of all twenty models in black, with recessions indicated by shaded bars (the black line is the same principal component shown in black in each of the panels of Figure 1). As expected, the principal component tends to peak during financial turmoil, recessions and periods of low real GDP growth or high inflation. It tends to bottom out after periods of sustained bullish stock markets and high real GDP growth. Evaluated by the first principal component, the one-year-ahead ERP reaches a local peak in June of 2012 at 12.2 percent. The surrounding months have ERP estimates of similar magnitude, with the most recent estimate in June 2013 at 11.2 percent. This behavior is not so clearly seen by simply looking at the collection of individual models in Figure 1, highlighting the usefulness of principal components analysis. Similarly high levels were seen in the mid and late 1970s, during a period of stagflation, while the recent financial crisis had slightly lower ERP estimates closer to 10 percent.

[Insert Figure 2 here]

Figure 2 also displays the 10^{th}, 25^{th}, 75^{th} and 90^{th} percentiles of the cross-sectional distribution of models. These bands can be interpreted as confidence intervals, since they give the range of the distribution of ERP estimates at each point in time. However, they do not incorporate other relevant sources of uncertainty, such as the errors that occur during the estimation of each individual model, the degree of doubt in the correctness of each model, and the correlation structure between these and all other kinds of errors. Standard error bands that capture all sources of uncertainty are therefore likely to be wider.

The difference in high and low percentiles can also be interpreted as measures of agreement across models. The interquartile range –the difference between the 25^{th} and 75^{th} percentiles— has compressed, mostly because the models in the bottom of the distribution have had higher ERP estimates since 2010. It is also interesting to note that the 75^{th} percentile has remained fairly constant over the last 10 years at a level somewhat below its long-run mean. The cross-sectional standard deviation in ERP estimates (not shown in the graph) also decreased from 10.2% in January of 2000 to 4.3% in June of 2013, confirming that the disagreement among models has decreased.

Another *a priori* reasonable summary statistic for the ERP is the cross-sectional mean of estimates across models. In Figure 3, we can see that by this measure the ERP has also been increasing since the crisis. However, unlike the principal component, it has not reached elevated levels compared to past values. The cross-sectional mean can be useful, but it has a few undesirable features as an overall measure of the ERP compared to the first principal component. First, it is procyclical, which contradicts the economic intuition that expected returns are highest in recessions, when risk aversion is high and future prospects look brighter than current ones. Second, it overloads on DDM simply because there is a higher number of DDM models in our sample. Lastly, it has a smaller correlation with the realized returns it is supposed to predict.

[Insert Figure 3 here]

5. The Term Structure of Equity Risk Premia

In Section 2, we described the term structure of the ERP – what expected excess returns are over different investment horizons. In practical terms, we estimate the ERP at different horizons by using the inputs for all the models at the corresponding horizons[17]. For example, if we want to take the historical mean of returns as our estimate, we can take the mean of returns over one month, six months, or a one-year period. In cross-sectional and time-series regressions, we can predict monthly, quarterly or annual returns using monthly, quarterly or annual right-hand side variables. DDM, on the other hand, have little variation across horizons. In fact, all the DDM we consider have a constant term structure of expected stock returns, and the only term structure variation in ERP estimates comes from risk-free rates[18].

Figure 4 plots the first principal components of the ERP as a function of investment horizon for some selected dates. We picked the dates because they are typical dates for when the ERP was unusually high or unusually low at the one-month horizon. As was the case for one-year-ahead ERP estimates, we can capture the majority of the variance of the underlying models at all horizons by a single principal component. The shares of the variance explained by the first principal components at horizons of one month to three years range between 68 and 94 percent. The grey line in Figure 4 shows the average of the term structure across all periods. It is slightly upward sloping, with a short-term ERP at just over 6 percent and a three-year ERP at almost 7 percent.

[Insert Figure 4 here]

[17] For other ways to estimate the term structure of the ERP using equilibrium models or derivatives, see Ait-Sahalia, Karaman and Mancini (2014), Ang and Ulrich (2012), van Binsbergen, Hueskes, Koijen and Vrugt (2014), Boguth, Carlson, Fisher and Simutin (2012), Durham (2013), Croce, Lettau and Ludvigson (2014), Lemke and Werner (2009), Lettau and Wachter (2011), Muir (2013), among others.

[18] In equation (3), ρ_{t+k} is assumed to be the same for all k, while risk-free rates are allowed to vary over the investment horizon k in equation (4). Of course, with additional assumptions, it is possible to have DDM with a non-constant term structure of expected excess returns.

The first observation is that the term structure of the ERP has significant time variation and can be flat, upward or downward sloping. Figure 4 also shows some examples that hint at lower future expected excess returns when the one-month-ahead ERP is elevated and the term structure is downward sloping, and higher future expected excess returns when the one-month-ahead ERP is low and the term structure is upward sloping. In fact, this is generally true: There is a strong negative correlation between the level and the slope of the ERP term structure of -71 percent. Figure 5 plots monthly observations of the one-month-ahead ERP against the slope of the ERP term structure (the three-year-ahead minus the one-month-ahead ERP) together with the corresponding ordinary least squares regression line in black. Of course, this is only a statistical pattern and should not be interpreted as a causal relation.

[Insert Figure 5 here]

6. Why is the Equity Risk Premium High?

There are two reasons why the ERP can be high: low discount rates and high current or expected future cash flows.

Figure 6 shows that earnings are unlikely to be the reason why the ERP is high. The green line shows the year-on-year change in the mean expectation of one-year-ahead earnings per share for the S&P 500. These expectations are obtained from surveys conducted by the Institutional Brokers' Estimate System (I/B/E/S) and available from Thomson Reuters. Expected earnings per share have been declining from 2010 to 2013, making earnings growth an unlikely reason for why the ERP was high in the corresponding period. The black line shows the realized monthly growth rates of real earnings for the S&P 500 expressed in annualized percentage points. Since 2010, earnings growth has been declining, hovering around zero for the last few months of the sample. It currently stands at 2.5 percent, which is near its long-run average.

[Insert Figure 6 here]

Another way to examine whether a high ERP is due to discount rates or cash flows is shown in Figure 7. The black line is the same one-year-ahead ERP estimate shown in Figure 2. The green line simply adds the realized one-year Treasury yield to obtain expected stock returns. The figure shows expected stock returns have increased since 2000, similarly to the ERP. However, unlike the ERP, expected stock returns are close to their long-run mean, and nowhere near their highest levels, achieved in 1980. The discrepancies between the two lines are due to exceptionally low bond yields since the end of the financial crisis.

[Insert Figure 7 here]

Figure 8 displays the term structure of the ERP under a simple counterfactual scenario, in addition to the mean and current term structures already displayed in Figure 4. In this scenario, we leave expected stock returns unmodified but change the risk-free rates in June 2012 from their actual values to the average nominal bond yields over 1960-2013. In other words, we replace R^f_{t+k} in equation (2) by the mean of R^f_{t+k} over t. The result of this counterfactual is shown in Figure 8 in green. Using average levels of bond yields brings the whole term structure of the ERP much closer to its mean level (the grey line), especially at intermediate horizons. This shows that a “normalization” of bond yields, everything else being equal, would bring the ERP close to its historical norm. This exercise shows that the current environment of low bond yields is capable, quantitatively speaking, of significantly contributing to an ERP as high as was observed in 2012-2013.

[Insert Figure 8 here]

7. Conclusion

We have analyzed twenty different models of the ERP by considering the assumptions and data required to implement them, and how they relate to each other. When it comes to the ERP, we find that there is substantial heterogeneity in estimation methodology and final estimates. We then extract the first principal component of the twenty models, which signals that the ERP in 2012 and 2013 is at heightened levels compared to previous periods. Our analysis provides evidence that the current level of the ERP is consistent with a bond-driven ERP: expected excess stock returns are elevated not because stocks are expected to have high returns, but because bond yields are exceptionally low. The models we consider suggest that expected stock returns, on their own, are close to average levels.

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Appendix A: Data Variables

Fama and French (1992)	http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html Monthly frequency; 1/1/1960 to 6/30/2013. We use 25 portfolios sorted on size and book to market, 10 portfolios sorted on momentum, realized excess market returns, HML, SMB, and the momentum factor.
Shiller (2005)	http://www.econ.yale.edu/~shiller/data.htm Monthly frequency; 1/1/1960 to 6/30/2013. We use the nominal and real price, nominal and real dividends and nominal and real earnings for the S&P 500, CPI, and 10 year nominal treasury yield.
Baker and Wurgler (2007)	http://people.stern.nyu.edu/jwurgler/data/Investor_Sentiment_Data_v23_POST.xlsx Monthly frequency; 7/1/1965 to 12/1/2010. We use the "sentiment measure".
Graham and Harvey (2012)	http://www.cfosurvey.org/index.htm Quarterly frequency; 6/6/2000 to 6/5/2013. We use the answer to the question "Over the next 10 years, I expect the average annual S&P 500 return will be: Expected return:" and the analogous one that asks about the next year.
Damodaran (2012)	http://www.stern.nyu.edu/~adamodar/pc/datasets/histimpl.xls Annual frequency; 1/1/1960 to 12/1/2012. We use the ERP estimates from his dividend discount models (one uses free-cash flow, the other one doesn't).
Gurkaynak, Sack and Wright (2007)	http://www.federalreserve.gov/pubs/feds/2006/200628/200628abs.html Daily frequency; starting on 6/14/61 for one- to seven-year yields; 8/16/71 for nine- and ten-year yields; 11/15/71 for eleven- to fifteen-year yields; 7/2/81 for sixteen- to twenty-year yields; 11/25/85 for twenty-one- to thirty-year yields. We use all series until 6/30/2013.
Gurkaynak, Refet, Sack and Wright (2010)	http://www.federalreserve.gov/econresdata/researchdata.htm Monthly frequency; 1/1/2003 to 7/1/2013. We use yields on TIPS of all maturities available.
Compustat	Variable BKVLPS Annual frequency; 12/31/1977 to 12/31/2012.
Thomson Reuters I/B/E/S	Variables EPS 1 2 3 4 5 Monthly frequency; 1/14/1982 to 4/18/2013 for current and next year forecasts; 9/20/84 to 4/18/2013 for two-year-ahead forecasts; 9/19/85 to 3/15/2012 for three-year-ahead forecasts; 2/18/88 to 3/15/07 for four-year-ahead forecasts.
FRED (St. Louis Federal Reserve)	http://research.stlouisfed.org/fred2/graph/?g=D9J and http://research.stlouisfed.org/fred2/graph/?g=KKk Monthly frequency. 1/1/1960 to 7/1/2013 for Baa minus Aaa bond yield spread and recession indicator.

Tables and Figures

Table I: Data sources	
Fama and French (1992)	Fama-French factors, momentum factor, twenty-five portfolios sorted on size and book-to-market
Shiller (2005)	Inflation and ten-year nominal treasury yield. Nominal price, real price, earnings, dividends and cyclically adjusted price-earnings ratio for the S&P 500
Baker and Wurgler (2007)	Debt issuance, equity issuance, sentiment measure
Graham and Harvey (2012)	ERP estimates from the Duke CFO survey
Damodaran (2012)	ERP estimates
Gurkaynak, Sack and Wright (2007)	Zero coupon nominal bond yields for all maturities[19]
Gurkaynak, Refet, Sack and Wright (2010)	Zero coupon TIPS yields for all maturities
Compustat	Book value per share for the S&P 500
Thomson Reuters I/B/E/S	Mean analyst forecast of expected earnings per share
FRED (St. Louis Federal Reserve)	Corporate bond Baa-Aaa spread and the NBER recession indicator

Note: All variables start in January 1960 (or later, if unavailable for early periods) and end in June 2013 (or until no longer available). CFO surveys are quarterly; book value per share and ERP estimates by Damodaran (2012) are annual; all other variables are monthly. Appendix A provides more details.

[19] Except for the 10-year yield, which is from Shiller (2005). We use the 10-year yield from Shiller (2005) for ease of comparability with the existing literature. Results are virtually unchanged if we use all yields, including the 10-year yield, from Gurkaynak, Sack and Wright (2007).

Table II: Models based on the historical mean of realized returns	
Long-run mean	Average of realized S&P 500 returns minus the risk-free rate using all available historical data
Mean of the previous five years	Average of realized S&P 500 returns minus the risk-free rate using only data for the previous five years

Table III: Dividend Discount Models	
Gordon (1962) with nominal yields	S&P 500 dividend-to-price ratio minus the ten-year nominal Treasury yield
Shiller (2005)	Cyclically adjusted price-earnings ratio (CAPE) minus the ten-year nominal Treasury yield
Gordon (1962) with real yields	S&P 500 dividend-to-price ratio minus the ten year real Treasury yield (computed as the ten-year nominal Treasury rate minus the ten year breakeven inflation implied by TIPS)
Gordon (1962) with earnings forecasts	S&P 500 expected earnings-to-price ratio minus the ten-year nominal Treasury yield
Gordon (1962) with real yields and earnings forecasts	S&P 500 expected earnings-to-price ratio minus the ten-year real Treasury yield (computed as the ten-year nominal Treasury rate minus the ten-year breakeven inflation implied by TIPS)
Panigirtzoglou and Loeys (2005)	Two-stage DMM. The growth rate of earnings over the first five years is estimated by using the fitted values in a regression of average realized earnings growth over the last five years on its lag and lagged earnings-price ratio. The growth rate of earnings from years six and onwards is 2.2 percent
Damodaran (2012)	A six-stage DDM. Dividend growth the first five stages are estimated from analyst's earnings forecasts. Dividend growth in the sixth stage is the ten-year nominal Treasury yield
Damodaran (2012) free cash flow	Same as Damodaran (2012), but uses free-cash-flow-to-equity as a proxy for dividends plus stock buybacks

Table IV: Models with cross-sectional regressions	
Fama and French (1992)	Uses the excess returns on the market portfolio, a size portfolio and a book-to-market portfolio as risk factors
Carhart (1997)	Identical to Fama and French (1992) but adds the momentum measure of Carhart (1997) as an additional risk factor
Duarte (2013)	Identical to Carhart (1997) but adds an inflation risk factor
Adrian, Crump and Moench (2014)	Uses the excess returns on the market portfolio as the single risk factor. The state variables are the dividend yield, the default spread, and the risk free rate

Table V: Models with time-series regressions	
Fama and French (1988)	Only predictor is the dividend-price ratio of the S&P 500
Goyal and Welch (2008)	Uses, at each point in time, the best out-of-sample predictor out of twelve predictive variables proposed by Goyal and Welch (2008)
Campbell and Thompson (2008)	Same as Goyal and Welch (2008), but imposes two restrictions on the estimation. First, the coefficient b in equation (9) is replaced by zero if it has the "wrong" theoretical sign. Second, we replace the estimate of the ERP by zero if the estimation otherwise finds a negative ERP
Fama and French (2002)	Uses, at each point in time, the best out-of-sample predictor out of three variables: the price-dividend ratio adjusted by the growth rate of earnings, dividends or stock prices
Baker and Wurgler (2007)	The predictor is Baker and Wurgler's (2007) sentiment measure. The measure is constructed by finding the most predictive linear combination of five variables: the closed-end fund discount, NYSE share turnover, the number and average first-day returns on IPOs, the equity share in new issues, and the dividend premium

Table VI: Surveys	
Graham and Harvey (2012)	Chief financial officers (CFOs) are asked since 1996 about the one and ten-year-ahead ERP. We take the mean of all responses

Table VII: ERP models

		Mean	Std. dev.	PC coefficients $\widehat{w}^{(m)}$	Exposure to PC $\widehat{load}_1^{(m)}$
Based on historical mean	Long-run mean	9.3	1.3	0.78	-0.065
	Mean of previous five years	5.7	5.8	0.42	-0.160
DDM	Gordon (1926): E/P minus nominal 10yr yield	-0.1	2.1	-0.01	0.001
	Shiller (2005): 1/CAPE minus nominal 10yr yield	-0.4	1.8	-0.10	0.011
	Gordon (1962): E/P minus real 10yr yield	3.5	2.1	0.69	-0.077
	Gordon (1962): Expected E/P minus real 10yr yield	5.3	1.7	-0.78	0.208
	Gordon (1962): Expected E/P minus nominal 10yr yield	0.4	2.3	-0.79	0.077
	Panigirtzoglou and Loeys (2005): Two-stage DDM	-1.0	2.3	0.07	-0.011
	Damodaran (2012): Six-stage DDM	3.4	1.3	-0.26	0.032
	Damodaran (2012): Six-stage free cash flow DDM	4.0	1.1	-0.62	0.053
Cross-sectional regressions	Fama and French (1992)	12.6	0.7	0.80	-0.040
	Carhart (1997): Fama-French and momentum	13.1	0.8	0.81	-0.042
	Duarte (2013): Fama-French, momentum and inflation	13.1	0.8	0.82	-0.044
	Adrian, Crump and Moench (2014)	6.5	6.9	-0.05	0.114
Time-series regressions	Fama and French (1988): D/P	2.4	4.0	-0.27	0.069
	Best predictor in Goyal and Welch (2008)	14.5	5.2	-0.07	0.023
	Best predictor in Campbell and Thompson (2008)	3.1	9.8	-0.12	0.081
	Best predictor in Fama French (2002)	11.9	6.8	-0.72	0.321
	Baker and Wurgler (2007) sentiment measure	3.0	4.7	-0.32	0.184
Surveys	Graham and Harvey (2012) survey of CFOs	3.6	1.8	0.72	0.264
	All models	5.7	3.2	0.78	-0.065

For each of the twenty models of the equity risk premium, we show four statistics. The first two are the time-series means and standard deviations for monthly observations from January 1960 to June 2013 (except for surveys, which are quarterly). The units are annualized percentage points. The third statistic, "PC coefficients $\widehat{w}^{(m)}$", is the weight that the first principal component places on each model (normalized to sum to one). The fourth is the "Exposure to PC $\widehat{load}_1^{(m)}$", the weight on the first principal component when each model is written as a weighted sum of all principal components (also normalized to sum to one).

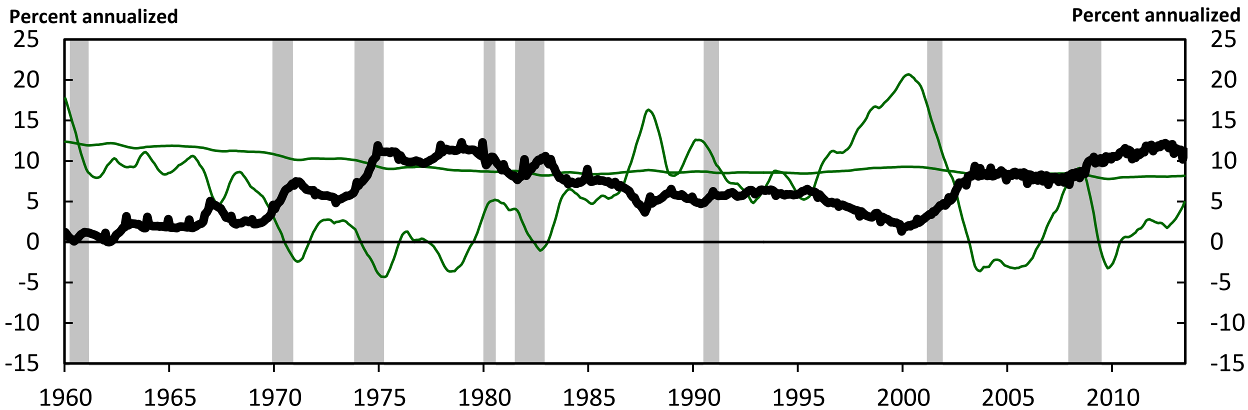
Table VIII: Correlation of ERP models

	LR mean	Mean past 5yr	E/P - 10yr	1/CAPE-10yr	E/P-real 10yr	Exp E/P-real 10yr	Exp E/P- 10yr	Two-stage DDM	Six-stage DDM	Free cash flow	FF	Carhart	Duarte	ACM	D/P	G and W	C and T	FF	Sentiment	CFO Survey
LR mean	100																			
Mean past 5yr	32	100																		
E/P - 10yr	8	15	100																	
1/CAPE-10yr	-9	0	78	100																
E/P-real 10yr	-11	25	98	23	100															
Exp E/P-real 10yr	-58	42	70	84	60	100														
Exp E/P- 10yr	-83	-61	84	95	46	98	100													
Two-stage DDM	17	27	88	54	89	66	79	100												
Six-stage DDM	3	-38	26	39	-30	32	52	-31	100											
Free cash flow	-43	-55	59	70	35	80	94	27	62	100										
FF	69	29	-8	-36	-21	-69	-91	9	-29	-77	100									
Carhart	71	30	-5	-31	-24	-71	-91	10	-25	-75	99	100								
Duarte	71	30	-3	-29	-22	-70	-91	11	-28	-74	99	100	100							
ACM	-1	-52	36	62	6	54	63	27	23	33	-28	-28	-25	100						
D/P	49	12	27	12	27	42	54	24	74	42	44	54	55	21	100					
G and W	25	12	25	21	-7	-36	-60	20	29	-9	7	13	14	-24	61	100				
C and T	27	31	14	-7	81	49	-60	28	-51	-40	60	57	58	-33	54	50	100			
FF	1	-30	-24	-29	37	-27	-37	-18	22	38	36	38	37	-9	40	23	43	100		
Sentiment	-10	33	-4	-20	68	-23	-29	27	-38	-20	18	17	18	-12	-38	-8	21	6	100	
CFO survey	-43	-33	12	30	1	1	13	16	5	-3	-36	-37	-39	60	14	-21	-32	-3	-36	100

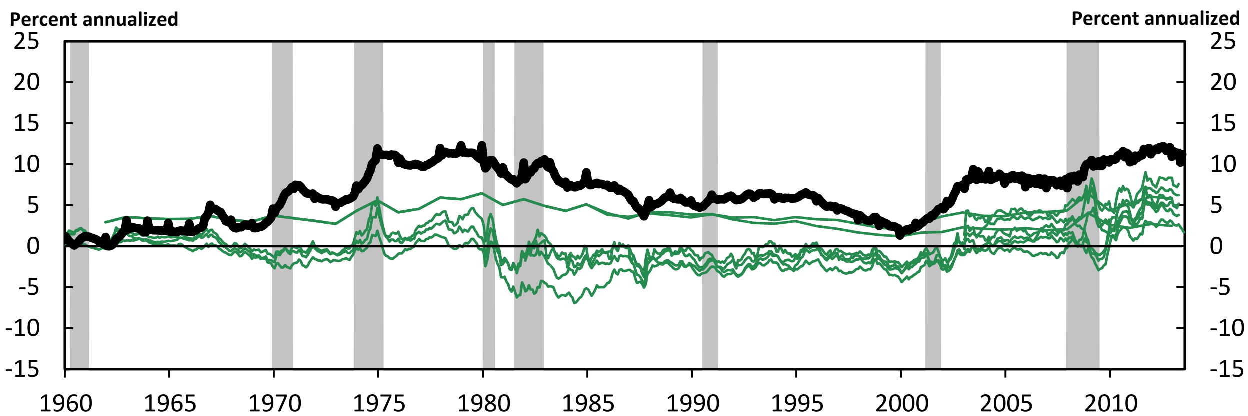
This table shows the correlation matrix of the twenty equity risk premium models we consider. Numbers are rounded to the nearest integer. Thick lines group models by their type (see Tables II to VI). Except for the CFO survey, the observations used to compute correlations are monthly for January 1960 to June 2013. For the CFO survey, correlations are computed by taking the last observation in the quarter for monthly series and then computing quarterly correlations.

Figure 1: ERP estimates for all models

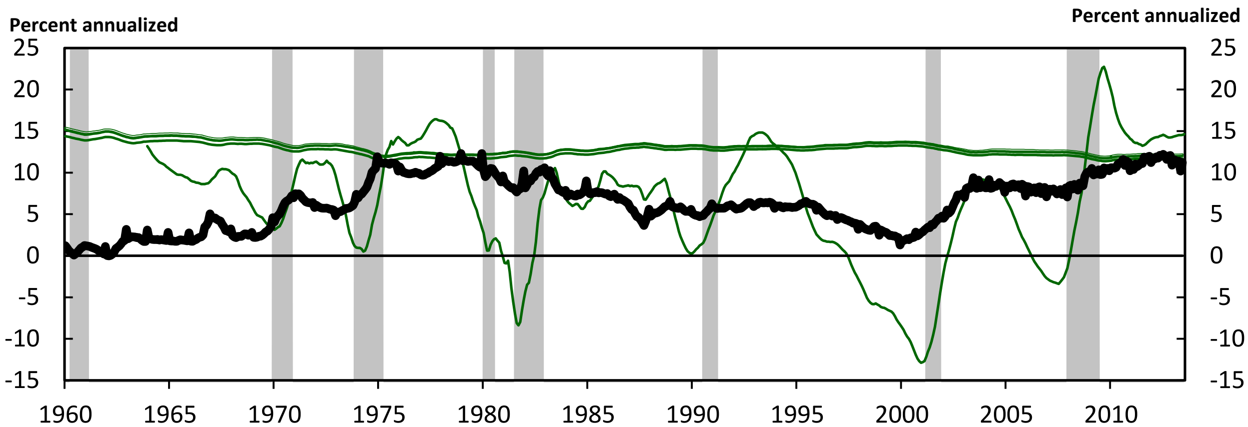
Panel 1: ERP models based on the historical mean of excess returns



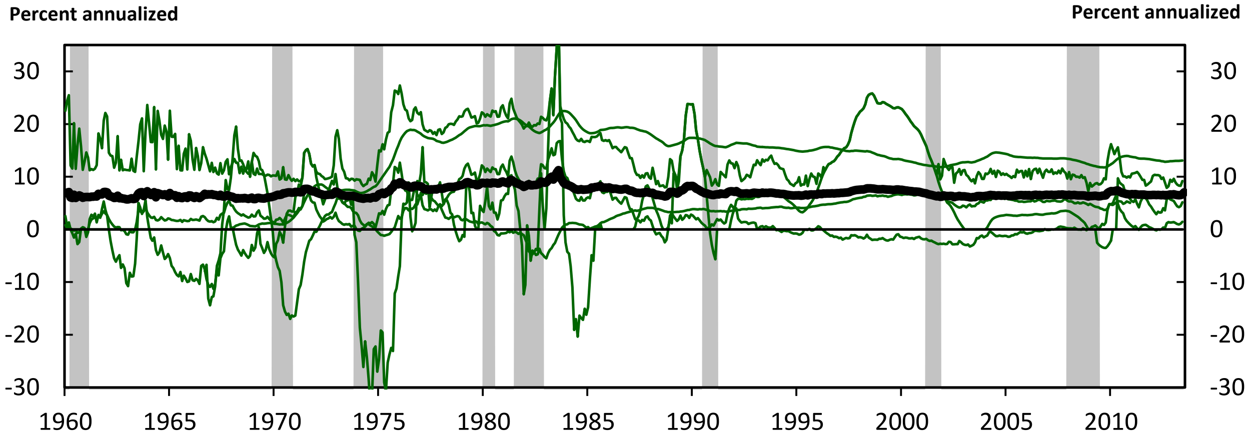
Panel 2: ERP dividend discount models (DDM)



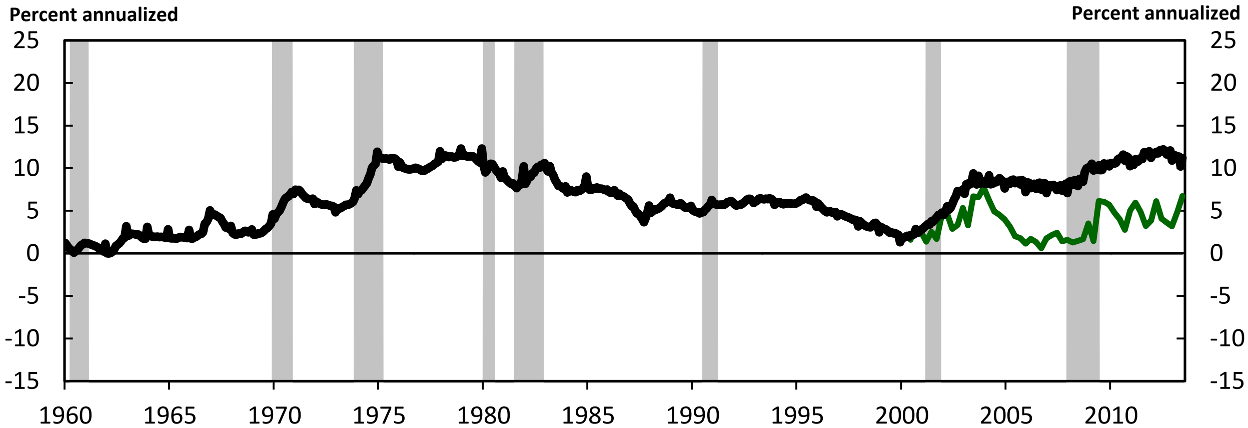
Panel 3: ERP cross sectional models



Panel 4: ERP time series models



Panel 5: ERP surveys

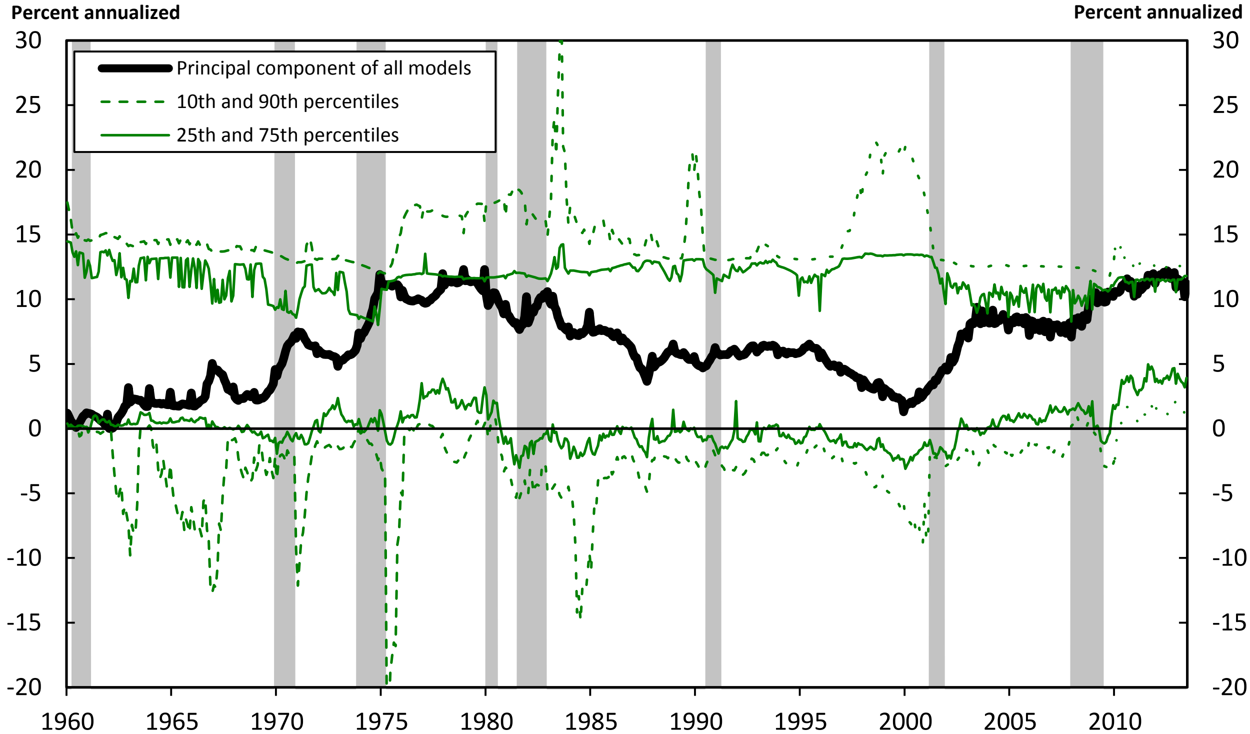


Each green line gives the one-year-ahead equity risk premium from each of the models listed in Tables II to VI. All numbers are in annualized percentage points.

Panel 1 shows the estimates for models based on the historical mean of excess returns, which are listed in Table II. Panel 2 shows estimates computed by the dividend discount models in Table III. Panel 3 uses the cross-sectional regression models from Table IV. Panel 4 shows the equity risk premium computed by the time-series regression models in Table V. Panel 5 gives the estimate obtained from the survey cited in Table VI.

In all panels, the black line is the first principal component of all twenty models (it can look different across panels due to different scales in the y-axis).

Figure 2: One-year-ahead ERP

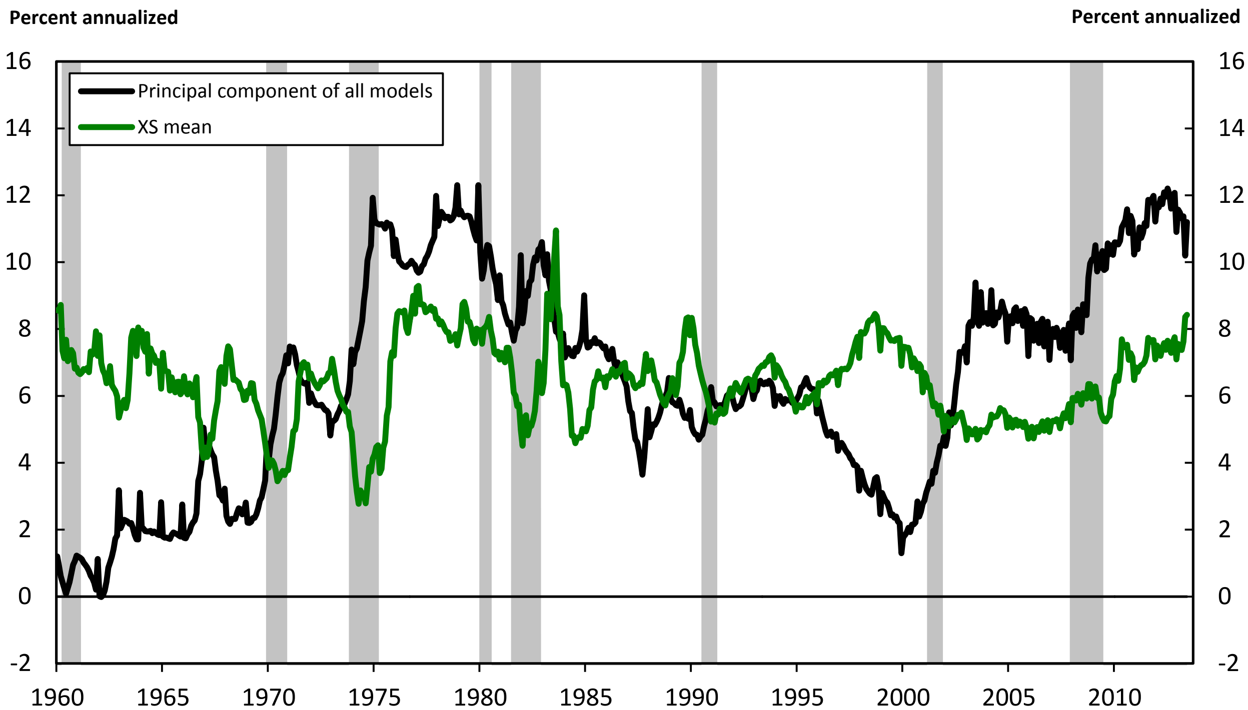


The black line is the first principal component of twenty models of the one-year-ahead equity risk premium (this is the same principal component shown in black in all panels of Figure 1). The models are listed in Tables II to VI.

The 25th and 75th percentiles (solid green lines) give the corresponding quartile of the 20 estimates for each time period, and similarly for the 10th and 90th percentiles (dashed green line).

Shaded bars indicate NBER recessions.

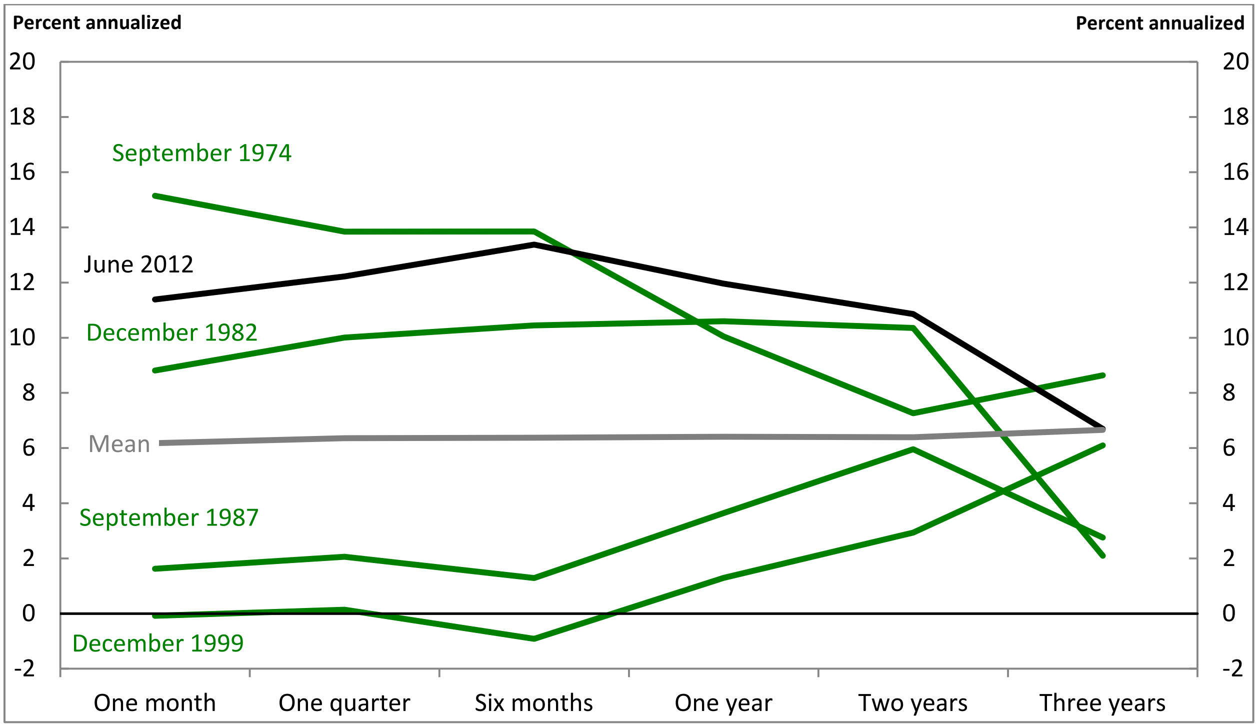
Figure 3: One-year-ahead ERP and cross-sectional mean of models



The black line is the first principal component of twenty models of the one-year-ahead equity risk premium (also shown in Figures 1 and 2). The green line is the cross-sectional average of models for each time period.

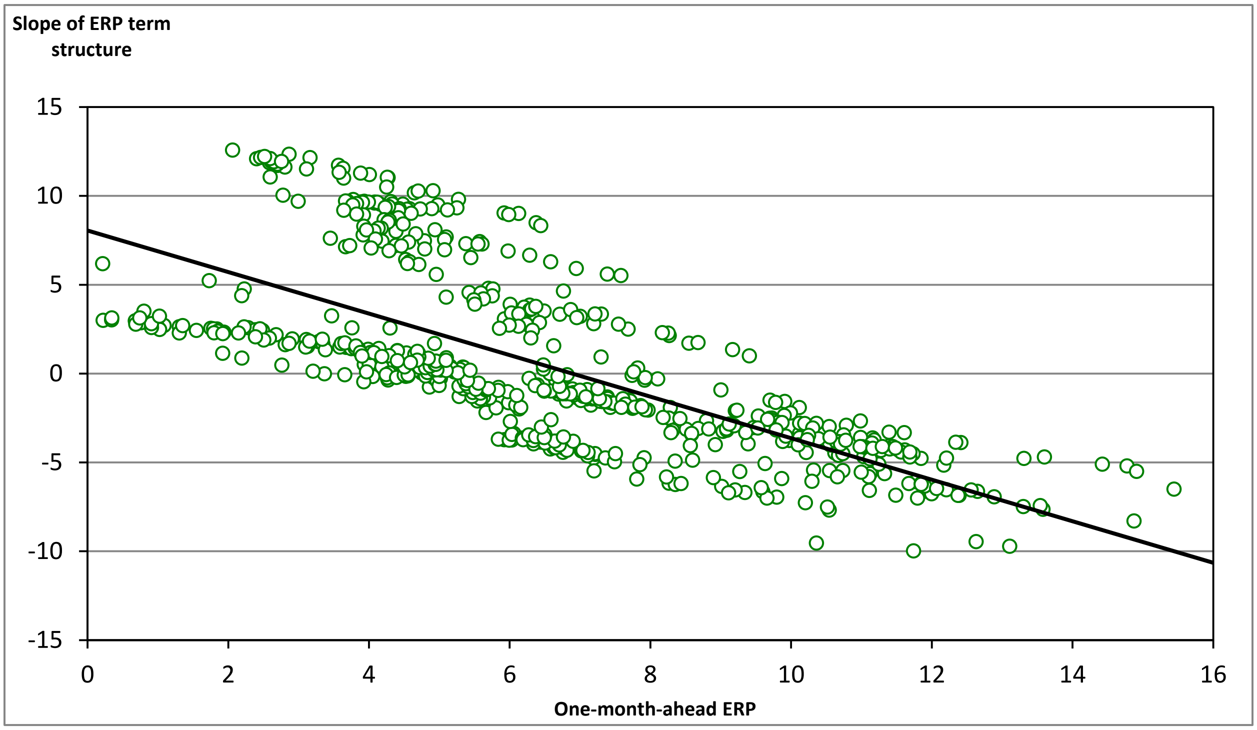
Shaded bars are NBER recessions.

Figure 4: Term structure of the ERP



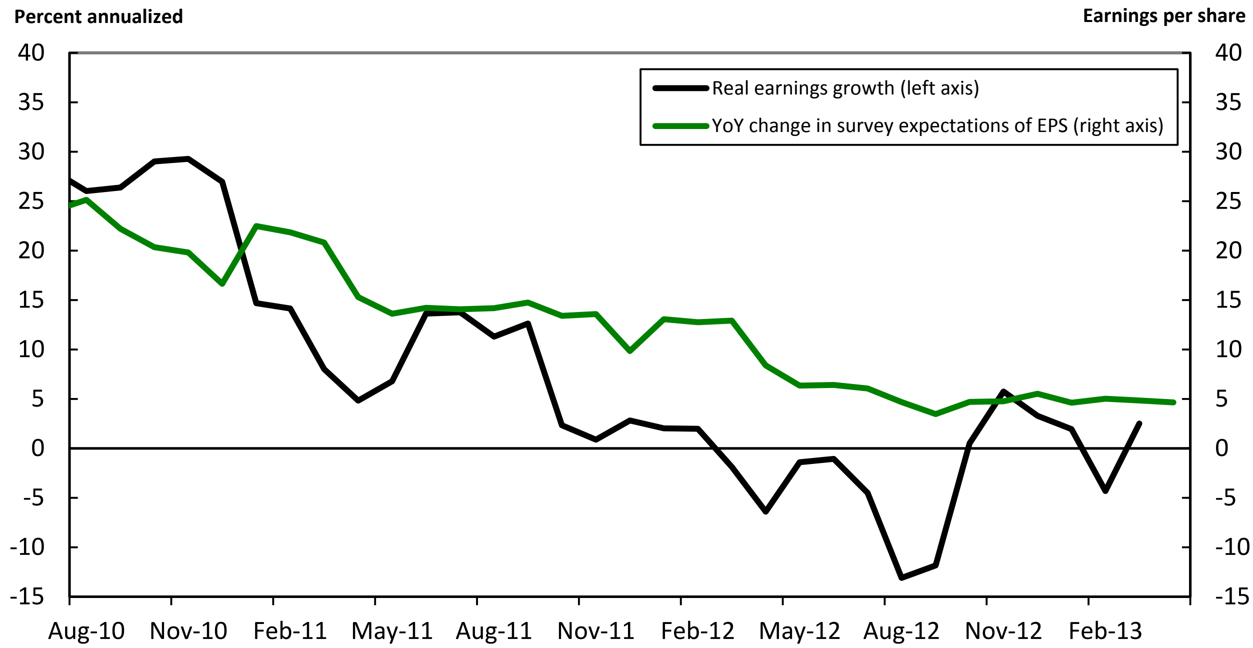
Each line, except for the grey one, shows equity risk premia as a function of investment horizon for some specific months in our sample. We consider horizons of one month, one quarter, six months, one year, two years and three years. The grey line (labeled "Mean") shows the average risk premium at different horizons over the whole sample January 1960 to June 2013. September 1987 and December 1999 were low points in one-month-ahead equity premia. In contrast, September 1974, December 1982 and June 2012 were peaks in the one-month-ahead equity premium.

Figure 5: Regression of the slope of the ERP term structure on one-month-ahead ERP



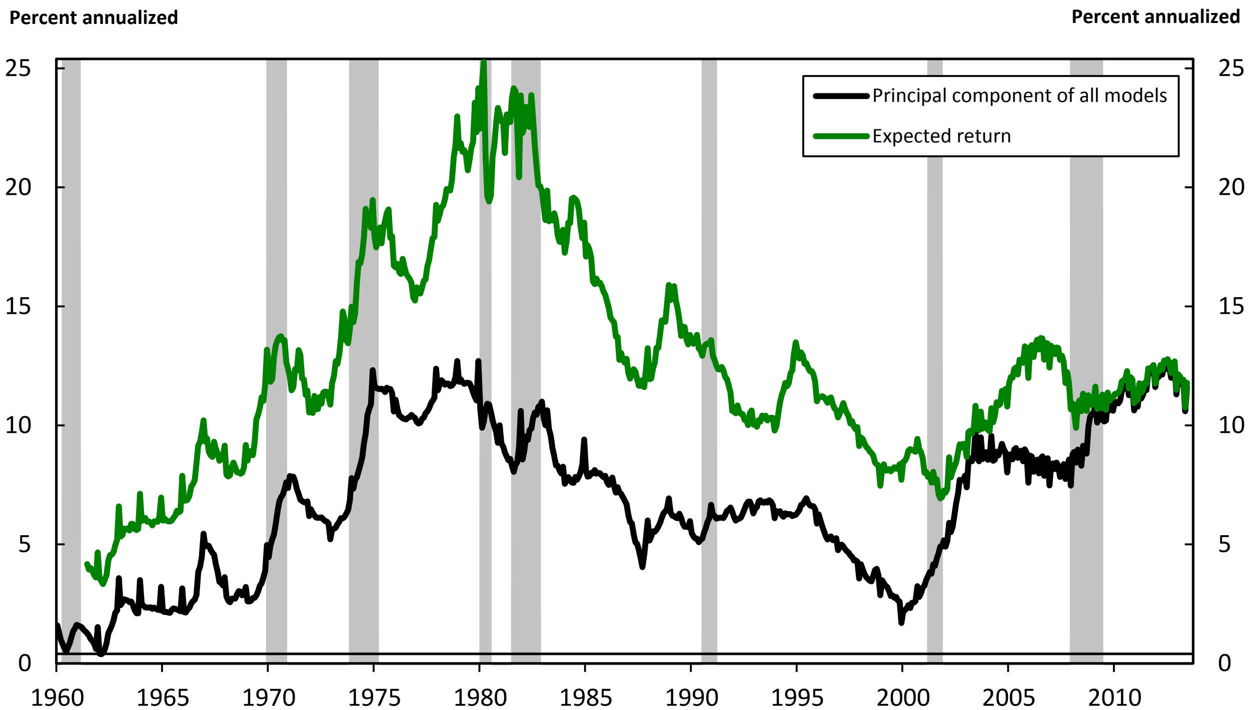
The figure shows monthly observations and the corresponding OLS regression for of the one-month-ahead ERP plotted against the slope of the ERP term structure for the period January 1960 to June 2013. The slope of the ERP term structure is the difference between the three-year-ahead ERP and the one-month-ahead ERP. All units are in annualized percentage points. The one-month-ahead and three-year-ahead ERP estimates used are the first principal components of twenty one-month-ahead or three-year-ahead ERP estimates from models described in Tables II-VI. The OLS regression slope is -1.17 (significant at the 99 percent level) and the R^2 is 50.1 percent.

Figure 6: Earnings behavior



The black line shows the monthly growth rate of real S&P 500 earnings, annualized and in percentage points. The green line shows the year-on-year change in the mean expectation of one-year-ahead earnings per share for the S&P 500 from a survey of analysts provided by Thomson Reuters I/B/E/S.

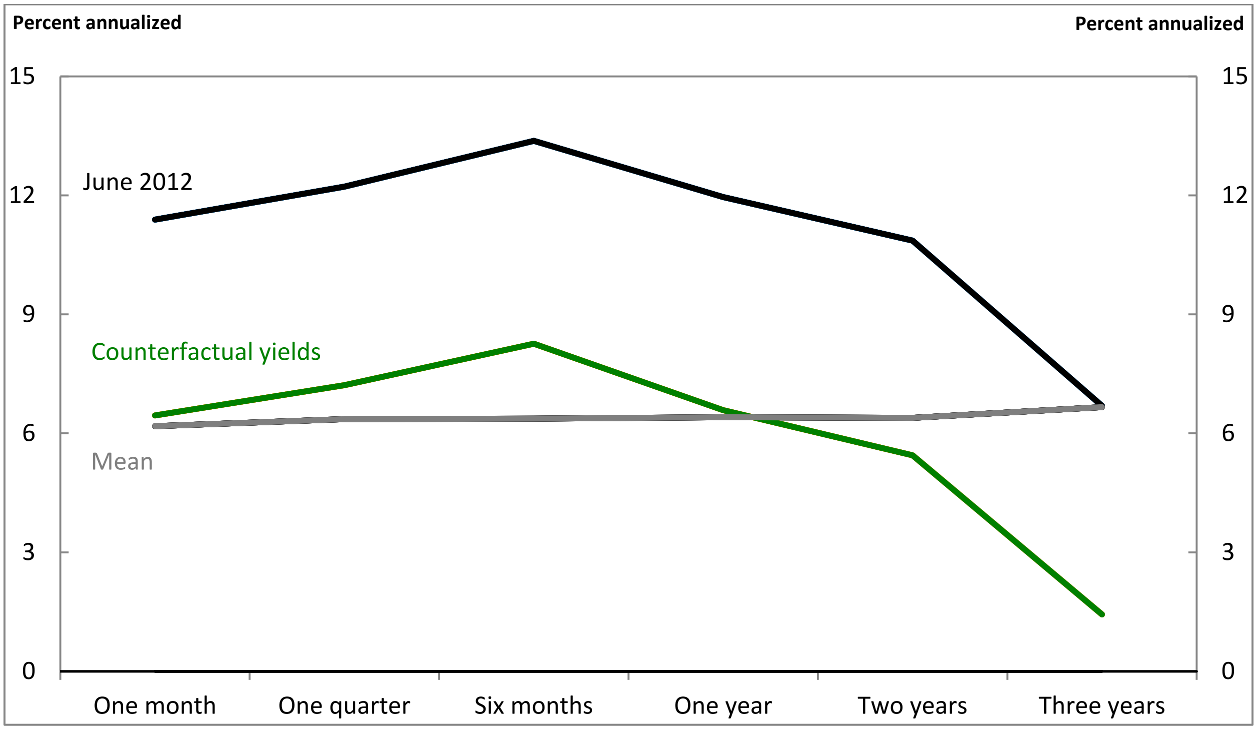
Figure 7: One-year-ahead ERP and expected returns



The black line is the first principal component of twenty models of the one-year-ahead equity risk premium (also shown in Figures 1, 2 and 3). The green line is the one-year-ahead expected return on the S&P 500, obtained by adding the realized one-year maturity Treasury yield from the principal component (the black line).

Shaded bars are NBER recessions.

Figure 8: Term structure of ERP using counterfactual bond yields



The grey line, labeled "Mean", shows the mean term structure of the equity risk premium over the sample January 1960 to June 2013. The black line, labeled "June 2012", shows the term structure for the most recent peak in the one-month-ahead ERP. These two lines are the same as in Figure 4. The green line, labeled "Counterfactual yields", shows what the term structure of equity risk premia would be in June 2012 if instead of subtracting June 2012's yield curve from expected returns we subtracted the average yield curve for January 1960 to June 2013.

Funds From Operations ("FFO") is a vital credit metric referenced by the credit rating agencies.

In the long-term, FFO is simply the net income of a Company plus depreciation.

$$\boldsymbol{FFO = Net\ Income + Depreciation} \qquad \textbf{\textit{(1)}}$$

This equation can be further developed by using the follow relationships:

$\boldsymbol{Net\ Income = ROE\ x\ Equity}$, and $\boldsymbol{Depreciation = \frac{Assets}{Life\ of\ Assets}}$

Substituting these equations into (1) results in the following relationship:

$$\boldsymbol{FFO = ROE\ x\ Equity + \frac{Assets}{Life\ of\ Assets}} \qquad \textbf{\textit{(2)}}$$

Furthermore, $\boldsymbol{Assets = Debt + Equity}$, and $\boldsymbol{\frac{1}{Life\ of\ Assets} = Depreciation\ Rate}$

Using these relationships and equation (2) results in the following:

$$\boldsymbol{FFO = ROE\ x\ Equity + Depreciation\ Rate\ x\ (Debt + Equity)}$$

The equation for the FFO / debt metric can therefore be derived as follows:

$$\boldsymbol{\frac{FFO}{Debt} = \frac{ROE\ x\ Equity + \textbf{Depreciation Rate}\ \text{x}\ (Debt + Equity)}{Debt}} \qquad \textbf{\textit{(3)}}$$

Simple mathematic distribution arrives at the following:

$$\boldsymbol{\frac{FFO}{Debt} = \frac{ROE\ x\ Equity}{Debt} + \frac{Depreciation\ Rate\ x\ (Debt + Equity)}{Debt}} \qquad \textbf{\textit{(4)}}$$

Further mathematical manipulation results in the following:

$$\boldsymbol{\frac{FFO}{Debt} = \frac{ROE\ x\ Equity}{Debt} + Depreciation\ Rate\ x\left(1 + \frac{Equity}{Debt}\right)} \qquad \textbf{\textit{(5)}}$$

Using the Company's depreciation rate[1], the 52.49% equity ratio described in Company witness Mr. Denato's rebuttal testimony and my recommended ROE of 10.75%, results in a 20% long-term FFO / debt as demonstrated below[2].

$$\frac{\boldsymbol{FFO}}{\boldsymbol{Debt}} = \frac{\mathbf{10.75\%}\ \boldsymbol{x}\ \mathbf{52.49\%}}{(\mathbf{1-52.49\%})} + \mathbf{3.9\%}\ \boldsymbol{x}\left(\mathbf{1} + \frac{\mathbf{52.49\%}}{(\mathbf{1-52.49\%})}\right) = \mathbf{20\%} \quad \textit{\textbf{(Ex. 1)}}$$

Alternatively, if the Commission orders an ROE of 10.00%, the equity ratio would need to be increased to 53.7% in order to solve for a resulting long-term FFO / debt of 20%.

$$\frac{\boldsymbol{FFO}}{\boldsymbol{Debt}} = \frac{\mathbf{10.00\%}\ \boldsymbol{x}\ \mathbf{53.7\%}}{(\mathbf{1-53.7\%})} + \mathbf{3.9\%}\ \boldsymbol{x}\left(\mathbf{1} + \frac{\mathbf{53.7\%}}{(\mathbf{1-53.7\%})}\right) = \mathbf{20\%} \quad \textit{\textbf{(Ex. 2)}}$$

[1] The depreciation rate as noted should be the inverse of the average remaining life of the assets. Given the long life of utility assets, 30 years of remaining life is not an unreasonable assumption which would indicate a rate of ~3.3%. Page 132 of Company 2017 10-K depreciation rates for the Electric and Gas Utility Property for 2017 are 3.9% and 2.9%, respectively. This example applies the electric rate of 3.9% which results in a higher FFO/debt for a given equity ratio and ROE combination. While credit rating agencies look at credit metrics on a company-wide basis instead of segment by segment, subsequent versions of this analysis may need to be revised to reflect more accurately the lower depreciation rates and the implied lower FFO/debt.

[2] A 20% long-term FFO / debt ratio is the minimum level the Company believes is supportive of long-term credit. A 20% ratio would indicate that the Company's debt would not exceed more than 5 years of cash flow. The analysis in this exhibit calculates a minimum FFO/debt ratio, and it would not be unreasonable for the Commission to authorize an ROE and equity ratio that would provide a higher FFO/debt ratio.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
19 April 2017

Update

Rate this Research

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A2
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

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

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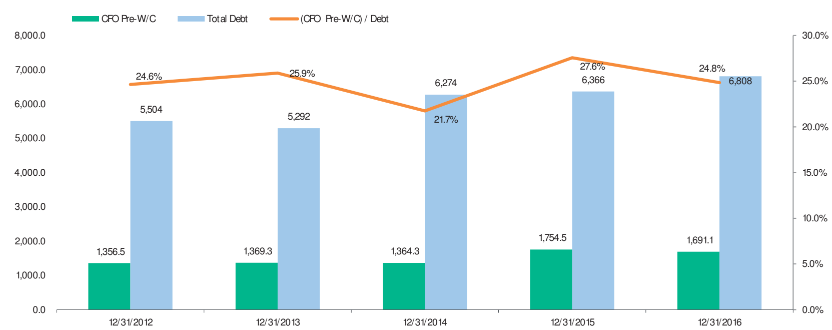
Consumers Energy Company

Vertically integrated electric and gas utility subsidiary of CMS

Summary Rating Rationale

Consumers Energy Company's (Consumers, (P)A2 stable) rating reflects its operations as an integrated electric and gas utility in an above average regulatory environment that allows for predictability of cash flows and results in strong cash flow credit metrics, even while the utility has been making significant investments into its electric and gas utility systems. We expect this phenomenon will continue for the foreseeable future. Consumers' strong stand alone performance has historically been offset by a significant debt load at its parent company CMS Energy (CMS, Baa1 stable) which constrains the utility's rating. However, over the past decade, CMS has made progress in reducing its consolidated leverage position as well as the percentage of parent debt in its capital structure. Partly as a result of this trend, the ratings of both CMS and Consumers were recently upgraded by one notch. All of Consumers' outstanding debt obligations are secured, and in accordance with our standard notching practice for utilities, are rated Aa3, two notches above our view of Consumers fundamental unsecured credit quality.

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



Source: Moody's Financial Metrics

Credit Strengths

» Supportive regulatory environment with prescriptive suite of recovery mechanisms

» Cash flow credit metrics that have strengthened through a build cycle

Credit Challenges

» Parent leverage remains relatively substantial

» Continued regulatory support will be needed to recover ongoing investment programs

Rating Outlook

Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive and allow the utility to recover, and earn a reasonable return on, prudently incurred capital investments such that the utility's financial profile will remain strong. For example, we anticipate over the next 12-18 months the ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to total debt will remain around 25%.

Factors that Could Lead to an Upgrade

» A sustained increase in cash flow or reduction in leverage leading to CFO pre WC to debt and interest coverage remaining meaningfully above 25% and 6.5 times

» A continued reduction in parent holding company debt

» If the Michigan regulatory environment were to become even more formulaic, transparent or timely with its suite of recovery mechanisms.

Factors that Could Lead to a Downgrade

» A change in Michigan's regulatory support leading to non-constructive outcomes in Consumer's rate cases

» A sharp deterioration of financial metrics such as CFO pre WC to debt falling to the high teens

» An increase in parent-level debt leading to a downgrade of CMS

Key Indicators

Exhibit 2

KEY INDICATORS [1]
Consumers Energy Company

	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016
CFO pre-WC + Interest / Interest	5.9x	6.0x	6.2x	7.4x	6.9x
CFO pre-WC / Debt	24.6%	25.9%	21.7%	27.6%	24.8%
CFO pre-WC – Dividends / Debt	17.5%	18.2%	14.4%	20.1%	17.5%
Debt / Capitalization	46.5%	43.1%	44.7%	43.5%	43.1%

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

Detailed Rating Considerations

Supportive regulatory environment with prescriptive suite of recovery mechanisms

Consumers benefits from an above average regulatory environment within the U.S. in terms of support to long term credit quality. Energy legislation passed by the Michigan legislature in 2008 provided the catalyst for this view as it streamlined the rate case process, reduced regulatory lag, placed a cap on customer participation in electric choice and provided financial support for utility investments. At the end of 2016, additional legislation was enacted to maintain retail energy markets that are competitive, affordable and reliable as the state transitions to a cleaner energy environment. The new legislation, which becomes effective on April 20, 2017, is also supportive of utility credit quality.

In accordance with the 2016 legislation, utility rate cases are still able to be filed on a forward test-year basis but must now be decided within ten months (reduced from twelve) of the date of filing. The offset to a faster rate process was the loss of the ability to self-implement after six months. While Michigan's electricity restructuring had initially contemplated full competition in generation, the 2008 legislation capped the number of customers able to choose an alternative supplier at 10% of the prior year load in the utility's service territory. The December 2016 legislation maintained the 10% retail open access (ROA) cap but also provides the potential for periodic downward adjustments if ROA demand is below the 10% cap. The 2016 legislation also requires, for the first time, that competitive retail suppliers demonstrate adequacy of electric supply for a multi-year period.

The 2016 legislation also provides additional assurance of recovery of utility investment by expanding the certificate of necessity (CON) process, which already included pre-construction approval and determination of rate making parameters for large generating resources, by adding an integrated resource planning (IRP) process. The IRP process will encompass a wide range of factors including fuel cost, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before constructing major projects. The legislation also lowers the CON threshold for major projects to $100 million from $500 million.

Utilities in the state also benefit from numerous formulaic rate adjustment mechanisms that provide a degree of cash flow stability and assurance of recovery. For example, Consumers has a forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, though interim gas inventory buildup could substantially increase the company's working capital financing when gas prices sharply increase.

Another form of forward-looking recovery mechanisms available is a 20-year levelized Renewable Energy Plan Surcharge (REPS). Michigan's Renewable Portfolio Standard (RPS) required that 10% of Consumer's retail sales be supplied by Michigan-based renewable sources by 2015 with up to 50% of that amount being provided by utility-owned facilities. With the completion of Cross Winds Energy Park in December 2014, Consumers met its renewable capacity requirement one year earlier than required. As the ultimate cost and performance of Consumer's current renewables portfolio has been more favorable than anticipated, the current surcharge has been reduced to zero. The 2016 legislation raised the state renewable requirement to 12.5% by 2019 and 15% by 2021, with a new renewable plus energy waste reduction goal of 35% by 2025. As noted above, future investments in renewables will be considered as part of the IRP process and if approved may be recovered through rates.

Gas utilities in the state also benefit from revenue decoupling mechanisms (RDM) and programs designed to assure recovery of needed infrastructure improvements. Consumers' RDM compares and adjusts for difference between weather normalized actual and authorized revenues. Consumers enhanced infrastructure replacement program (EIRP), is a Michigan Public Service Commission (MPSC) authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing approximately 540 miles of cast iron pipe and other high-risk components. Consumers currently projects that it will spend about $75 million per year under the EIRP. These expenditures are recoverable through base rates.

Recent Rate Case Activity

Electric - In February 2017, the MPSC authorized a $113 million electric rate increase for Consumers premised on a 10.1% return on equity (ROE). The increase was slightly more than half of the $208 million requested in Consumers March 2016 filing, which requested an ROE of 10.7%. Consumers previously authorized ROE was 10.3%, approved in November 2015. We view this outcome as evidence of continued reasonable regulatory treatment. Consumers also requested an investment recovery mechanism (IRM) that would enable it to recover capital investments of $222 million between 2017 and 2019, however the MPSC did not authorize the IRM, so Consumers will continue to seek recovery through its regular (likely annual) rate case filings. As such, on March 31, 2017, Consumers requested a $172.8 million (4.2%) electric rate increase premised on a 10.5% ROE. In accordance with current law (effective through April 20, 2017), a final decision is required within 12 months, and the utility will be permitted to implement interim rates after 180 days.

Gas - In April 2016, the MPSC approved a settlement agreement authorizing a $40 million annual rate increase, versus a request of $72.4 million. The order did not specify an ROE, but allowed continuation of Consumers' previously approved 10.3% ROE for reporting and for calculations that require its use. The filing, made in July 2015, requested a 10.7% ROE. The request was made to recover investments in system reliability, compliance with regulations and to enhance technology, and also sought to establish an investment recovery mechanism (IRM) that would provide automatic revenue increased in 2017, 2018 and 2019. The IRM was not approved.

In August 2016, Consumers filed a new gas rate case with the MPSC seeking an annual rate increase of $90.5 million, based on a 10.6% authorized ROE. Consumers once again requested an IRM that would allow it to increase rates in 2018 and 2019 ($35.4 million in each year) to recover investments planned for those years. In December 2016, the MPSC staff recommended authorization of the investment IRM but recommended rate increases of $17 million in 2018 and $16.6 million in 2019. In January 2017, the staff also recommended a 9.5% ROE. In January 2017, the utility implemented an interim increase of $20 million. We view the recent indication of staff support for an IRM mechanism (albeit at lower levels than requested) that could provide cash flow certainty while extending the time between rate case filings, as credit supportive.

Evolving generation profile

Consumers has been actively reducing its carbon footprint and moving toward more energy efficient, cleaner generating resources. In 2016, the utility closed seven smaller older coal plants (total 900 MW); in 2015 it closed three small gas plants and acquired the 540 MW Jackson gas-fired generating facility. As a result, the company's generating resource base shifted from 41% coal in 2005 to 21% in 2017, over the same time period, renewable capacity (including contracted renewables) increased from 3% to 10%.

Going forward, the company will focus on developing resources that are "clean, and lean" (more efficient/cost effective). In 2016, over half of Consumer's electric generation was provided via power purchase agreements or market purchases. The majority of this production comes from two power purchase agreements, one with the 1,240 MW MCV gas-fired facility (approximately 14% of 2016 production) that terminates in March 2025, and a second with the 798 MW Palisades nuclear facility (approximately 19% of 2016 production) that had been scheduled to terminate in 2022. As discussed below, in December 2016, Consumers reached an agreement for the early termination of the Palisades contract which will result in savings for its customers.

The upcoming expiration of both the Palisades and MCV contracts provide Consumers the opportunity to replace older, less efficient technology with more cost effective resources. In April 2017, Consumers issued a request for proposals for 800 MW of operational gas-fired capacity to replace these contracts. We expect that CMS will bid its 750 MW natural gas-fired Dearborn Industrial Generation (DIG) merchant generating project into this independent third party monitored process. If the DIG project is deemed the best alternative, it would provide Consumers needed capacity along with an opportunity to earn a return on the associated incremental rate base. An acquisition of DIG by Consumers would also reduce risk within the consolidated CMS organization by further limiting the already modest amount of merchant generating exposure within the family, a credit positive.

Termination of Palisades PPA

Consumers currently has a power purchasing agreement (PPA) that enables it to purchase up to 798 MW annually from the Palisades nuclear plant that is owned by Entergy Corporation (Entergy, Baa2 stable). The PPA was set to expire in 2022, however, prices that Consumers pays for under the PPA (over $50 MWh) are above market power prices. In December 2016 CMS and Entergy reached an agreement to terminate the PPA in May 2018. Consumers expects that the early termination of the PPA will result in an estimated $344 million of savings, and has agreed to share these with Entergy. As such, Consumers will make a termination payment of $172 million to Entergy, with the other $172 million to be reflected in lower electric customer rates. The agreement is subject to the MPSC's approval of Consumer's recovery of the termination fee. Consumers has submitted a request to recover the termination payment through securitization and the MPSC indicated it will make a final determination by September 2017. If the MPSC does not approve the termination agreement, the PPA will remain in place until April 2022.

Michigan state statutes allow utilities to securitize restructuring-related regulatory assets and stranded costs and the MPSC has a history of approving securitization bonds. Most recently, in 2013, the MPSC authorized Consumers' issuance of securitization bonds to finance the recovery of the remaining book value of the seven smaller coal-fired electric generating plants that were retired in April 2016 and three smaller natural gas-fired units that were retired in June 2015. Approximately $378 million of securitization bonds were issued through a Consumers securitization subsidiary in 2014. Principal and interest payments are made semi-annually through the maturity of the bonds in 2029.

Michigan's economy is doing well

According to Moody's Economy.com, Michigan's economy is currently in recovery and is humming along nicely with job growth outpacing the Midwest average and slightly ahead of the U.S. average. Manufacturing is expected to perform better than average this year thanks to the resilience of the auto industry. In 2016, vehicle sales leveled off at about 17.5 million units, almost twice their recessionary low, and 2017 started on a strong note. Outside of autos, education, healthcare, life sciences, green technology and IT are said to hold the most promise. Longer term Michigan is expected to slightly underperform the U.S. due to comparatively weak demographics. We expect the Michigan regulatory construct to continue to provide the ability for utilities to recover the cost of needed infrastructure improvements.

Capital spending is expected to remain elevated

Consumers plans to continue its elevated capital investment program for foreseeable future. The magnitude of the plan, which is intended to improve reliability and efficiency while moving the company to a less carbon intensive future, will require continued regulatory support in order to maintain the company's financial profile. In 2017, projected investments are approximately $1.8 billion compared to around $1.6 billion in 2016 and $1.5 billion in 2015. Over the 2017-2021 period, the utility company has projected $9.0 billion of capital investments which will include maintenance capital of about $4.6 billion (approximately $2.6 billion for electric operations and $2.0 billion for gas utility operations), an additional $2.5 billion aimed at making further improvements in electric and gas infrastructure and reliability, about $500 million for environmental projects, and around $300 million for advanced metering infrastructure for both electric and gas customers.

Although Consumers' investment program remains quite sizable, we expect the utility will continue its focus on cost containment and operational efficiency in an effort to minimize the rate impact to its customers. Consumers aim to keep rate increases modest should increase the likelihood of continued regulatory support. Funding for these forecasted expenditures will be provided by internally generated cash flows including the benefits of extended bonus depreciation, the issuance of debt at Consumers' and equity contributions from CMS.

Strong credit metrics have been maintained through continued investment cycle

Consumers capital program increased from about $1.2 billion in 2012 to about $1.65 billion in 2016 and, as noted above, is expected to remain elevated. Throughout the period, the utility has maintained strong financial metrics. As of December 2016, its three year average ratio of CFO pre-WC to debt was about 25%, which is in the mid-section of the "A" scoring range of 22%-30% for this metric indicated in our rating methodology for electric and gas utilities. It is worth noting that although about 1/3 of Consumers assets and cash flow are generated by its lower risk gas utility operations, we evaluate the combined utility's credit profile using our standard grid. Consumers 25% average CFO pre-WC to debt metric falls in the upper portion of the 19%-27% "A" scoring range indicated in the low business risk grid typically utilized for gas utilities. Over the next 12-18 months, assuming continued regulatory support and Consumers' focus on cost containment, we anticipate metrics will remain near their current levels. Consumers' interest coverage ratio is over 6x, which scores in the "Aa" range for this metric.

Liquidity Analysis

Consumers liquidity profile is average. The utility's continuing capital expenditure program and dividend policy results in negative free cash flow for the foreseeable future; however, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the year end 2016, Consumers generated approximately $1.68 billion of cash from operations (CFO), invested $1.65 billion in capital investments and up streamed about $500 million in dividend payments to CMS, resulting in a negative free cash flow (FCF) of approximately $480 million that was somewhat offset by parent contributions of $275 million. In 2015 Consumers generated CFO of approximately $1.8 billion, invested $1.5 billion in capital investments and up streamed about $480 million in dividend payments, resulting in a negative FCF of $220 million offset by parent contributions of $150 million. CMS relies on Consumers upstream dividends to pay its interest expense, which amounts to around $150 million per year. Consumers policy is to grow its dividend with earnings, maintaining a payout ratio in the 80% range. After consideration of parent contributions, in 2016, Consumers' net dividends to its parent equate to about 40% of its net income.

Consumers external liquidity sources include a $650 million secured revolving credit facility expiring May 2021, a $250 million secured credit facility terminating in November 2018, and a $30 million secured revolving letter of credit facility expiring in May 2018. These credit facilities provide support for working capital needs and backstop Consumers' $500 million commercial paper program. The credit facilities do not include a material adverse change representation for new borrowings, and only one financial covenant, maintenance of debt to capital of less than 65%. As of December 31,2016, debt to capital was 49%.

As of December 31, 2016, Consumers had approximately $398 million of commercial paper outstanding, no borrowings under its various credit facilities and $37 million in aggregate of letters of credit outstanding. In addition to approximately $25 million of annual amortization of its securitization bonds, Consumers nearest long-term debt maturities are $100 million of first mortgage bonds coming due in October of 2017 and $180 million due in March 2018.

CMS' liquidity needs are supported by a $550 million revolving credit facility that expires in May 2021. At December 31, 2016, CMS had $1 million of letters of credit outstanding, and no borrowings under its credit facility. CMS' credit facility has one financial covenant, a maximum debt to EBITDA of 6 times and as of December 31, 2016 debt to EBITDA was 4.2 times.

Structural Considerations

Consumers strong stand alone performance has been offset by a significant debt load at its parent company. However, over the past decade, CMS has made slow but steady progress in reducing its consolidated leverage position as well as the percentage of parent debt in its capital structure. As of December 31, 2016, including Moody's standard adjustments, CMS had approximately $3.9 billion of consolidated debt outside of Consumers, or approximately 37% of its consolidated total debt. Of this amount, approximately $1.2 billion represents deposits of EnerBank, an FDIC-insured industrial bank providing unsecured consumer installment loans for financing home improvements wholly owned by CMS and supported by approximately $1.3 billion of notes receivable. Excluding self-funding EnerBank, CMS's parent level debt is approximately $2.7 billion or about 26% of its consolidated total, or about 29% of the total of Consumers plus pure parent level debt. This is significantly lower than the 36% level exhibited at the end of 2006; however, at close to 30%, it is still a key driver of the two notch rating differential between Consumers' and CMS' senior unsecured ratings.

Corporate Profile

Consumers Energy Company (Consumers) is a vertically integrated electric and gas utility serving approximately 6.7 million customers in the state of Michigan with 2016 revenue of approximately $6.1 billion. Consumer's electric operations account for approximately two thirds of its revenue, cash flow and asset base. Consumers is the primary subsidiary of CMS Energy Corporation (CMS), representing over 95% of its consolidated cash flow. In addition to Consumers, CMS owns approximately 1,177 gross MW of unregulated, primarily natural gas-fired, generation located mostly within Michigan, and EnerBank, a FDIC-insured industrial bank providing unsecured consumer installment loans for financing home improvements. These businesses contribute modestly to consolidated results, and do not materially increase the company's consolidated business risk profile.

Rating Methodology and Scorecard Factors

Exhibit 3

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 12/31/2016		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.8x	Aa	6.8x - 7.3x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	24.7%	A	25% - 28%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	17.3%	A	17% - 20%	A
d) Debt / Capitalization (3 Year Avg)	43.8%	A	40% - 44%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A1
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A2		A1
b) Actual Rating Assigned		(P)A2		(P)A2

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 12/31/2016
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Ratings

Exhibit 4

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	Aa3
First Mortgage Bonds	Aa3
Senior Secured	Aa3
Senior Unsecured Shelf	(P)A2
Pref. Stock	A3
Commercial Paper	P-1
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Sec Bank Credit Facility	A3
Senior Unsecured	Baa1

Source: Moody's Investors Service

REPORT NUMBER 1061631

MOODY'S
INVESTORS SERVICE

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 8-K
CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) March 6, 2018

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110

The name and address of the registrant have not changed since the last report.

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 8.01. Other Events.

As previously disclosed, the Georgia Public Service Commission ("PSC") issued an order on the federal tax reform legislation enacted in December 2017 (the "Tax Reform Legislation") requiring Georgia Power Company ("Georgia Power") to submit its analysis of the Tax Reform Legislation and related recommendations to address the impacts on Georgia Power's cost of service and annual revenue requirements by March 6, 2018.

On March 6, 2018, Georgia Power and the staff of the Georgia PSC reached a settlement agreement (the "Tax Reform Settlement Agreement") regarding the retail rate impact of the Tax Reform Legislation. Pursuant to the Tax Reform Settlement Agreement, to reflect the federal income tax rate reduction impact of the Tax Reform Legislation, Georgia Power would refund to customers $185 million and $145 million as a bill credit for calendar years 2018 and 2019, respectively. In addition, Georgia Power would defer as a regulatory liability (1) the revenue equivalent of the tax expense reduction resulting from legislation lowering the Georgia state income tax rate from 6.00% to 5.75% in 2019 and (2) the entire benefit of approximately $700 million in federal and state excess accumulated deferred income taxes. The amortization of these regulatory liabilities would be addressed in Georgia Power's next base rate case, which is scheduled to be filed by July 1, 2019. If there is not a base rate case in 2019, customers will continue to receive $185 million in annual bill credits, with any additional federal income tax savings deferred as a regulatory liability, until Georgia Power's next base rate case.

To address the negative cash flow and credit metric impacts of the Tax Reform Legislation, Georgia Power's equity ratio (currently approximately 51%) would be increased to the lower of (1) Georgia Power's actual common equity weight in its capital structure and (2) 55%, until Georgia Power's next base rate case. Benefits from reduced federal income tax rates in excess of the amounts refunded to customers will be retained by Georgia Power to cover the carrying costs of the incremental equity in 2018 and 2019.

The Tax Reform Settlement Agreement is subject to approval by the Georgia PSC. Accordingly, the terms of the Tax Reform Settlement Agreement are subject to change and the terms of any final agreement approved by the Georgia PSC may differ materially from the terms of the Tax Reform Settlement Agreement. The ultimate outcome of this matter cannot be determined at this time.

Cautionary Note Regarding Forward-Looking Statements

Certain information contained in this Current Report on Form 8-K is forward-looking information based on current expectations and plans that involve risks and uncertainties. Forward-looking information includes, among other things, statements concerning the Tax Reform Settlement Agreement. Georgia Power cautions that there are certain factors that could cause actual results to differ materially from the forward-looking information that has been provided. The reader is cautioned not to put undue reliance on this forward-looking information, which is not a guarantee of future performance and is subject to a number of uncertainties and other factors, many of which are outside the control of Georgia Power; accordingly, there can be no assurance that such suggested results will be realized. The following factors, in addition to those discussed in Georgia Power's Annual Report on Form 10-K for the year ended December 31, 2017, and subsequent securities filings, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and Internal Revenue Service interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of Georgia Power; state and federal rate regulations and the impact of pending and future rate cases and negotiations, including those related to the Tax Reform Settlement Agreement; changes in Georgia Power's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements; and the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of U.S. Department of Energy loan guarantees. Georgia Power expressly disclaims any obligation to update any forward-looking information.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Date: March 6, 2018

GEORGIA POWER COMPANY

By /s/David P. Poroch

David P. Poroch
Comptroller and Vice President

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Consideration of the stipulation and settlement agreement between Gulf Power Company, the Office of Public Counsel, Florida Industrial Power Users Group, and Southern Alliance for Clean Energy regarding the Tax Cuts and Jobs Act of 2017.	DOCKET NO. 20180039-EI ORDER NO. PSC-2018-0180-FOF-EI ISSUED: April 12, 2018

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
JULIE I. BROWN
DONALD J. POLMANN
GARY F. CLARK
ANDREW GILES FAY

APPEARANCES:

JEFFREY A. STONE and RUSSELL A. BADDERS, ESQUIRES, One Energy Place, Pensacola, Florida 32520-0100; Beggs & Lane, P. O. Box 12950, Pensacola, Florida 32576-2950
On behalf of Gulf Power Company (Gulf).

J.R. KELLY and CHARLES REHWINKEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

JON MOYLE and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG).

SUZANNE BROWNLESS, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

MARY ANNE HELTON, ESQUIRE, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Advisor to the Florida Public Service Commission.

KEITH HETRICK, ESQUIRE, General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Florida Public Service Commission General Counsel.

FINAL ORDER APPROVING JOINT MOTION TO APPROVE STIPULATION AND SETTLEMENT AGREEMENT

BY THE COMMISSION:

BACKGROUND

On February 14, 2018, Gulf Power Company (Gulf) filed a Stipulation and Settlement Agreement (SSA) between Gulf and the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), and the Southern Alliance for Clean Energy (SACE) regarding the Tax Cuts and Jobs Act of 2017 in Docket Nos. 20180013-PU,[1] the generic tax docket, and 20160186-EI,[2] Gulf's last base rate case proceeding. The SSA addresses the effects of the passage of the Tax Cuts and Jobs Act of 2017 (Act), signed into law by President Trump on December 22, 2017. The signatories to the SSA are OPC, FIPUG and SACE, all of whom were signatories to Gulf's last rate case stipulation.[3]

The SSA implements paragraph 6 of Gulf's 2017 Stipulation and Settlement Agreement (2017 Settlement) approved by Order No. PSC-17-0178-S-EI.[4] There are six basic parts to the SSA: 1) base rate reduction of $18.2 million per year commencing on April 1, 2018;[5] 2) establishment of a regulatory liability to account for the tax rate reduction from January 1, 2018 until the effective date of the base rate reduction;[6] 3) refund of $69.4 million by the end of 2018 through the fuel cost recovery clause for the unprotected excess deferred tax regulatory liability as of December 31, 2017;[7] 4) reduction of $15.6 million to Environmental Cost Recovery Clause (ECRC) recovered by the end of 2018;[8] 5) establishment of a 53.5% equity ratio cap for all retail regulatory purposes, e.g., earnings surveillance reporting, interim rate determinations, cost recovery clauses;[9] and 6) initiation of a limited scope proceeding by May 1, 2018, for the purpose of determining the amount and flow back period for protected excess deferred taxes through a prospective reduction in base rates, should one be warranted.[10] The SSA is intended to resolve all of Gulf's outstanding tax issues associated with the Act.

On February 19, 2018, pursuant to Section 366.076(1), Florida Statutes, this docket was opened to expedite consideration of the SSA as requested by the signatories so that the base rate reduction agreed to by the parties, if appropriate, can be implemented in April 2018. On February 26, 2018, Gulf filed a Joint Motion to Approve Stipulation and Settlement Agreement (Motion) requesting that the SSA be approved in its entirety and that this Commission take final

[1] Docket No. 20180013-PU, In re: Petition to establish a generic docket to investigate and adjust rates for 2018 tax savings, by Office of Public Counsel.
[2] Docket No. 20160186-EI, In re: Petition for rate increase by Gulf Power Company.
[3] Order No. PSC-17-0178-S-EI, issued on May 16, 2017, in Docket No. 160186-EI, In re: Petition for rate increase by Gulf Power Company.
[4] Id.
[5] Paragraphs 2, 4.
[6] Paragraphs 5, 8.
[7] Paragraph 7.
[8] Paragraph 9.
[9] Paragraph 11.
[10] Paragraph 13.

action no later than March 26, 2018, which would allow the tariffs filed with the Motion to become effective in April 2018. Gulf states that the SSA is in the best interest of Gulf's ratepayers as it allows for a reduction in base rates shortly after the Act's passage as well as reducing the Environmental Cost Recovery Clause factors, and returning unprotected excess deferred income taxes to customers more rapidly than normally done. All parties to this docket - OPC, FIPUG and SACE - as joint movants to Gulf's Motion support the Motion.

On March 20, 2018, Gulf filed amended tariffs correcting scrivener's errors in the tariffs filed on February 26, 2018. On March 26, 2018, we held an administrative hearing on this matter in which Gulf's customers and interested persons were provided with an opportunity to present public testimony and voice any concerns with the SSA. Gulf sponsored witnesses Robin Boren, Rhonda Alexander, and Lee Evans, who answered questions under oath about the SSA, and four exhibits were admitted into evidence.

DECISION

The standard for approval of a settlement agreement is whether it is in the public interest.[11] A determination of public interest requires a case-specific analysis based on consideration of the proposed settlement taken as a whole.[12]

As testified to by Gulf's witnesses, effective the first billing cycle of April 2018, this SSA greatly benefits ratepayers by implementing a base rate decrease of $18.2 million per year associated with the reduction of the corporate income tax rate from 35 to 21 percent. This reduction will remain in effect until Gulf's next base rate case. Further, Gulf's customers will also receive $69.4 million through the Fuel Clause in 2018 associated with unprotected accumulated deferred income taxes that would normally be amortized over a 5 to 10 year period. Finally, Gulf's ratepayers will immediately see a $15.6 million reduction in the Environmental Cost Recovery Clause factor which would normally not be implemented until January of 2019. Combined, Gulf's ratepayers will see a $103.2 million reduction in charges in 2018. Although Gulf's equity ratio cap will increase from 52.5% to 53.5% to allow the refund of $103.2 million in one year, the equity ratio is well within the normal, accepted equity range and will maintain Gulf's financial stability. The issue of excess protected deferred income taxes, which total

[11] Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company; Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company; PSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

[12] Order No. PSC-13-0023-S-EI, at p. 7.

approximately $386.1 million per year, has not been resolved by this SSA. The parties will continue to work on a mutually acceptable resolution to this issue and, if none can be reached by May 1, 2018, Gulf will file a petition for a limited proceeding in this docket to resolve the issue.

Based on our review of the SSA, the exhibits entered into the record, the support of the Parties, the testimony provided by Gulf witnesses, and the benefits to Gulf customers discussed above, we find that the SSA, taken as a whole, is in the public interest. Therefore, the SSA is hereby approved.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Joint Motion to Approve Stipulation and Settlement Agreement between Gulf Power Company, the Office of Public Counsel, the Florida Industrial Power Users Group, and the Southern Alliance for Clean Energy, dated February 14, 2018, is hereby granted and the Stipulation and Settlement Agreement, Attachment A hereto, approved. It is further

ORDERED that the revised tariff sheets implementing the Stipulation and Settlement Agreement between Gulf Power Company, the Office of Public Counsel, the Florida Industrial Power Users Group, and the Southern Alliance for Clean Energy, dated February 14, 2018, reflecting the approved final rates and charges, as filed on February 26, 2018, and amended on March 20, 2018, are hereby approved effective the first billing cycle of April 2018. It is further

ORDERED that this docket shall remain open for disposition by this Commission of the issue of protected excess deferred income taxes.

By ORDER of the Florida Public Service Commission this 12th day of April, 2018.

/s/ Carlotta S. Stauffer
CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Gulf Power

Rhonda J. Alexander
Manager
Regulatory, Forecasting & Pricing

One Energy Place
Pensacola, FL 32520-0780
850 444 6743 tel
850 444 6026 fax
rjalexad@southernco.com

February 14, 2018

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20160186-EI
Docket No. 20180013-PU

Dear Ms. Stauffer:

Attached for official filing in the above-referenced docket is a Stipulation and Settlement Agreement of Gulf Power Company, the Office of Public Counsel, the Florida Industrial Power Users Group, and the Southern Alliance for Clean Energy.

Sincerely,

Rhonda J. Alexander

Rhonda J. Alexander
Regulatory, Forecasting and Pricing Manager

md

Attachments

cc: Gulf Power Company
Jeffrey A. Stone, Esq., General Counsel
Beggs & Lane
Russell Badders, Esq.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to establish a generic docket to investigate and adjust rates for 2018 tax savings, by Office of Public Counsel.	Docket No. 20180013-PU
In re: Petition for rate increase by Gulf Power Company.	Docket No. 20160186-EI
	Filed: February 14, 2018

STIPULATION AND SETTLEMENT AGREEMENT

WHEREAS, Gulf Power Company ("Gulf" or the "Company"), the Citizens of Florida through the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), and the Southern Alliance for Clean Energy ("SACE") have signed this Stipulation and Settlement Agreement (the "Agreement") which is submitted to the Florida Public Service Commission ("Commission") for its review and approval (unless the context clearly requires otherwise, the term "Party" or "Parties" means a signatory to this Agreement, whether or not specifically named above); and

WHEREAS, on December 22, 2017, the President of the United States signed the Tax Cuts and Jobs Act (G.L.c 164, § 94) ("the Act") previously passed by both houses of the Congress of the United States, and the effective date of the Act became January 1, 2018; and

WHEREAS, on January 9, 2018, OPC petitioned the Commission to establish a generic docket to investigate and adjust rates for all investor owned utilities to reflect the reduction in federal income tax expense caused by the Act, resulting in the establishment of Docket No. 20180013-PU; and

WHEREAS, on January 30, 2018, FIPUG filed its notice in Docket No. 20180013-PU that it joins the Petition filed on or about January 9, 2018 by OPC; and

WHEREAS, OPC, and by its joinder, FIPUG, explicitly acknowledged in the January 9, 2018 petition that Gulf is one of four utilities that should be exempted from Docket No. 20180013-PU as a result of the specific provisions regarding tax reform contained in the comprehensive settlement agreement between OPC and Gulf filed on March 20, 2017 ("the 2017 comprehensive settlement agreement"), later signed by FIPUG and SACE, and subsequently approved by the Commission as evidenced by its Order No. PSC-2017-0178-S-EI, issued May 16, 2017 ("the 2017 Rate Order"); and

WHEREAS, the 2017 comprehensive settlement agreement and the 2017 Rate Order established the new 2017 base rates for Gulf that took effect on July 1, 2017; and

WHEREAS, pursuant to paragraph 6 in the 2017 comprehensive settlement agreement between the Parties, the prospective adjustment to base rates is to be based on the net operating income effect of the change in the income tax rate from 35 percent to 21 percent, based on the base rate revenue increase authorized by Order No. PSC-2017-0178-S-EI, with an assumed impact of $1.3 million per each percentage point of income tax rate change. This formulation results in a prospective reduction to Gulf's new 2017 base rates totaling $18.2 million on an annual basis; and

WHEREAS, the intent of the Parties in formulating paragraph 6 in the 2017 comprehensive settlement agreement was to provide for an expedited permanent base rate reduction on a going-forward basis solely due to the impact of the change in federal income tax rates on the revenue requirements embedded in the new 2017 base rates resulting from the 2017 comprehensive settlement agreement, in this instance with a filing requirement on or before the 60th day following the effective date of the new income tax rates; and

WHEREAS, the Parties to this Agreement have undertaken to resolve the issues raised by the enactment of the Act so as to maintain a degree of reasonableness, stability and predictability with respect to Gulf's base rates and charges; and

WHEREAS, the Parties have entered into this Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as a part of the negotiated exchange of consideration among the Parties to this Agreement, each has agreed to concessions to the others with the expectation that all provisions of the Agreement will be enforced by the Commission as to all matters addressed herein with respect to all Parties, upon acceptance of the Agreement as provided herein and upon approval in the public interest;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. This Agreement shall be in lieu of and as a complete substitution for Gulf's involvement in Docket No. 20180013-PU as a party with regard to the matters addressed herein, and Gulf shall not be subject to discovery requests in that docket with regard to such matters.

2. This Agreement will become effective upon Commission approval, and the rate changes agreed to herein, except as otherwise provided in this Agreement, shall be effective April 1, 2018 (the "Implementation Date"). The base rate changes shall be applied to meter readings beginning with the first billing cycle for April 2018 ("cycle one"), regardless of the actual date the cycle one meter readings occur, and shall continue until Gulf's base rates are next reset in a general base rate proceeding. The other rate changes agreed to herein shall also be applied to meter readings beginning with cycle one for April 2018, regardless of the actual date the cycle one meter readings occur, except as otherwise

provided in this Agreement, and shall continue until such rates are reset by the Commission in the normal course of the ongoing cost recovery clause dockets in which such rates are normally addressed.

3. In the event that the achieved effective date for new rates is less than 30 days following a vote by the Commission to approve this Agreement, the Parties agree that the public interest warrants implementation of the new reduced rates using meter readings less than 30 days following said vote and hereby waive any rights that may otherwise apply with regard to such effective date.

4. The annualized impact on Gulf's base rates associated with the Act is a reduction of $18.2 million per year and shall be implemented as a reduction to the current base rates (newly established and implemented in 2017 by the 2017 comprehensive settlement agreement) through the package of new 2018 rates set forth in Attachment A. The revised tariff sheets reflecting the revised rates shall be submitted by Gulf under separate cover letter.

5. Because the effective date of the Act is January 1, 2018, bills rendered on meter readings starting with cycle one for February 2018 and continuing until the effective date of the base rate reduction identified in paragraph 4 are not able to reflect the tax rate reduction of the Act. Therefore, a regulatory liability will be established that initially consists of an amount equal to 1/24th of the $18.2 million annualized impact for the billing month of January, plus 1/12th of the $18.2 million annualized impact for the billing month of February, plus 1/12th of the $18.2 million annualized impact for the billing month of March (and, if necessary, any additional subsequent billing month prior to the actual effective date of new 2018 rates provided for herein). The accumulated balance in this

regulatory liability shall be refunded to Gulf's retail customers through a credit to the fuel cost recovery clause. In this fashion, the full annualized impact of the tax savings resulting from the Act will be either reflected in prospective base rates or as a credit to the benefit of customers in 2018. The refund to customers provided under this paragraph shall be in lieu of any other assertion of continuing jurisdiction over Gulf's base rates for periods prior to the prospective application of the new 2018 rates provided for herein.

6. The excess accumulated deferred income taxes created by the Act are accounted for as regulatory liabilities under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) paragraphs ASC 740-10-30-8, ASC 740-10-25-47, ASC 740-10-35-4 and ASC 740-10-55-23. In order to become compliant with these standards, Gulf restated the deferred taxes at December 31, 2017, to the new rates and booked the difference as regulatory liabilities. Some of these excess accumulated deferred income taxes (referred to as "protected" deferred taxes) relate to depreciable property and must be returned to customers over a specified time under provisions in federal law governing the flow back of the excess under principles of normalization.

7. Gulf contends that the remaining excess accumulated deferred income taxes (referred to as "unprotected" deferred taxes), while not subject to the same normalization provisions under federal law as the "protected" deferred taxes, would expose Gulf to added risk from future increases in federal tax over the next 20 years (the average remaining life of the underlying assets) if flowed back to customers over a shorter time frame. The Parties agree that the "unprotected" excess deferred tax regulatory liability shall be addressed as follows:

   a. The "unprotected" deferred tax liability as of December 31, 2017 shall be refunded to customers with the retail portion ($69,407,000) credited to customers through the fuel cost recovery clause, and the cost recovery rates for the fuel cost recovery clause shall be reduced for the remainder of 2018 as provided in paragraph 8 below such that the full amount of the resulting credit is refunded to customers through rates in 2018.

b. In the event of a subsequent increase to the federal income tax rate applicable to Gulf that takes effect prior to 2038, Gulf shall be entitled to initiate a regulatory proceeding to address recovery through rates of any portion of the "unprotected" deferred tax liability credited to customers in accordance with this paragraph 7 that would then no longer be excess deferred taxes under the applicable tax law if the accelerated credit to customers resulting from this Agreement had not occurred. The Parties to this Agreement are not precluded from participating in any such proceeding with all rights conferred to a party therein.

8. The credits to the fuel cost recovery clause set forth in paragraphs 5 and 7 above shall be combined for use in calculating revised fuel cost recovery rates for the remainder of 2018 designed to refund to customers the full combined amount through rates in 2018. The effective date for the new fuel cost recovery rates shall be the same as the effective date for new 2018 base rates established pursuant to this Agreement.

9. Because of the significant level of investment reflected in the 2018 rates established for Gulf's Environmental Cost Recovery Clause ("ECRC"), the tax rate change in the Act also has a sizable impact on recoverable costs in 2018. As a result, Gulf shall implement revised ECRC rates for the remainder of 2018 that reflect a reduction of $15.6 million, which is estimated to be the full annual impact of the tax rate change on 2018 recoverable costs. The effective date for the new ECRC rates shall be the same as the effective date

for new 2018 base rates established pursuant to this Agreement. Any difference between the estimated impact credited to customers through this reduction in rates and the actual impact shall be addressed, resolved and trued-up through the normal process associated with the ECRC mechanism. The new fuel cost recovery rates to be implemented pursuant to paragraph 8 above and the revised ECRC rates for the remainder of 2018 to be implemented pursuant to this paragraph 9 are set forth in Attachment B. The revised tariff sheets reflecting the revised rates shall be submitted by Gulf under separate cover letter.

10. Gulf contends that returning the full amount of "unprotected" deferred taxes to customers in 2018, along with the loss of bonus depreciation, will put a strain on Gulf's credit metrics (specifically its Funds From Operations ("FFO") to Debt) over the short and long term. To offset this contended adverse impact on Gulf's financial integrity, Gulf has stated its intent to fund 100 percent of the $69.4 million refund to its customers with common equity.

11. The Parties agree that the first sentence in paragraph 3(b) of the 2017 comprehensive settlement agreement between the Parties approved by Order No. PSC-2017-0178-S-EI is hereby amended by replacing "52.5%" with "53.5%". In all other respects, paragraph 3(b) of the 2017 comprehensive settlement agreement remains unchanged.

12. For purposes of transition, the remaining amount of the additional common equity not already reflected in the May 2018 Surveillance Report shall be added to the weighted average cost of capital ("WACC") before use in the cost recovery clause filings normally based in part on the WACC from the May 2018 Surveillance Report (this transition adjustment is so that a full 13/13ths of the increased common equity related to replacing

the unprotected excess deferred taxes in Gulf's capital structure is included for all future cost recovery clause filings). The revised cost of capital revenue requirement rate set forth in Attachment B shall be used for all cost recovery clause purposes for costs incurred after January 1, 2018, beginning January 1, 2018, until such rate is superseded by the May 2018 Surveillance WACC as adjusted by operation of this paragraph 12.

13. The Parties acknowledge that, within the scope of paragraph 6 of the 2017 comprehensive settlement agreement, work is required to determine whether it is possible to recognize the flow back of the "protected" excess deferred taxes as an additional reduction in Gulf's base rates while remaining consistent with provisions in federal law governing the flow back of the excess under principles of normalization, and if so determined, whether such recognition is desirable to the Parties. It is the desire and intent of the Parties that the rate reductions agreed to elsewhere in this Agreement not be held up pending the additional work required as noted above. The Parties therefore agree that they will either submit a later agreement on the issue regarding "protected" excess deferred taxes identified and reserved for future determination under this paragraph 13 or initiate a limited scope proceeding, by May 1, 2018, for the purpose of determining the amount and flow back period of the "protected" excess deferred taxes through a prospective reduction in base rates. Any further base rate reduction resulting from such later agreement or limited scope proceeding within the scope of paragraph 6 of the 2017 comprehensive settlement agreement as set forth in this paragraph 13 shall be implemented on a prospective basis only no earlier than cycle one meter readings for January 2019. There will be an annual flow back or amortization of the "protected" excess deferred taxes in accordance with federal law establishing and governing the

principles of normalization, and the unamortized portion of the "protected" excess deferred tax regulatory liability shall continue to be included as a cost-free source of capital in Gulf's capital structure. Resolution of the subject matter identified and reserved for future determination under this paragraph 13 shall not become a vehicle to revisit or alter the resolution of the issues addressed by the rate reductions set forth in paragraphs 4, 5 and 7 above which are intended to be the complete and final determination of the matters addressed therein.

14. Pending resolution of the matters reserved under paragraph 13 above, for 2018, Gulf shall initially accrue an amount to a regulatory liability account established pursuant to this Agreement (the "2018 Tax Refund Reserve") that is the projected annual revenue requirement impact of reflecting the flow-back or amortization of the "protected" excess deferred taxes to customers under the Average Rate Assumption Method used following the Tax Reform Act of 1986. The amount so accrued shall be trued up to the actual annual amount for 2018 under the methodology required by federal law establishing and governing the principles of normalization as applied under the Act. Unless the Parties agree to some other disposition as part of the resolution of the matters reserved under paragraph 13 above, the amount so accrued to the 2018 Reserve, including the true-up amount, shall be refunded to Gulf's retail customers during the full calendar year 2019 through a credit to the fuel cost recovery clause in the same manner used to refund the "unprotected" excess deferred taxes through the fuel cost recovery clause rates during the remainder of 2018. The associated reduction in the fuel cost recovery rates from what would otherwise be applicable shall be effective for bills rendered on meter readings starting with cycle one for January 2019, regardless of the actual date the cycle one meter

readings occur.

15. The Parties request that the Commission consider and approve this Agreement at the earliest possible date so that final agency action will allow implementation in accordance with paragraph 2 above. Notwithstanding the desire and agreement of the Parties regarding the implementation date for new rates as set forth in paragraph 2 above, new rates agreed to herein shall not be implemented with an effective date prior to cycle one meter readings for the first calendar month following the Commission's issuance of final order, or in the event that the approval occurs through the Proposed Agency Action ("PAA") process, a Consummating Order in connection with any Proposed Agency Action Order approving this Agreement thereby rendering such PAA as final agency action.

16. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof.

17. Except as expressly amended herein in paragraph 11, the 2017 comprehensive settlement agreement is not modified by this Agreement. Nothing in this Agreement shall be construed as a precedent in any other docket nor will any affiliate of Gulf cite or suggest any treatment of capital structure provided for in this Agreement should govern or be used as guidance or precedent in any Commission Docket pending on the effective date.

18. The provisions of this Agreement are contingent on approval of this Agreement in its entirety by the Commission without modification. The Parties agree that approval of this Agreement is in the public interest. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome, or result in conflict with the terms of this Agreement in any administrative or judicial proceeding relating to,

reviewing, or challenging the establishment, approval, adoption, or implementation of this Agreement or the subject matter hereof. No party will assert in any proceeding before the Commission or any court that this Agreement or any of the terms in the Agreement shall have any precedential value, except to enforce the provisions of this Agreement. Approval of this Agreement in its entirety will resolve all matters and issues as they may relate to Gulf Power Company in Docket No. 20180013-PU, pursuant to and in accordance with Section 120.57(4), Florida Statutes. Gulf will be excused from further participation in Docket No. 20180013-PU, and the docket will be closed with regard to any issues affecting Gulf Power effective on the date of the Commission vote approving this Agreement. No Party shall seek appellate review of any order issued in regards to this Agreement. The prohibition against seeking appellate review of any order issued in regards to this Ageement shall not apply to any order resulting from the limited scope proceeding, if any, arising from the provisions of paragraph 13 above.

19. This Agreement is dated as of February 14, 2018. It may be executed in counterpart originals, and a scanned .pdf copy of an original signature shall be deemed an original. Any person or entity that executes a signature page to this Agreement shall become and be deemed a Party with the full range of rights and responsibilities provided hereunder, notwithstanding that such person or entity is not listed in the first recital above and executes the signature page subsequent to the date of this Agreement, it being expressly understood that the addition of any such additional Party (or Parties) shall not disturb or diminish the benefits of this Agreement to any current Party.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signature on one of the following pages.

Respectfully submitted,

Jeffrey A. Stone
Florida Bar No. 325953
Vice President, General Counsel & Corporate Secretary
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0100
(850) 444-6550

Respectfully submitted,

____

J. R. Kelly, Public Counsel
Charles J. Rehwinkel, Deputy Public Counsel
Stephanie Morse, Associate Public Counsel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
Office of Public Counsel

Attorneys for the Citizens of Florida

Respectfully submitted,

Feb. 14, 2018

Jon C. Moyle, Jr., Esquire
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Attorneys for the Florida Industrial Power Users Group (FIPUG)

Respectfully submitted,

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(954) 295-5714 (tel)
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On Behalf of Southern Alliance for Clean Energy (SACE)

Rate Design Materials

This attachment is organized in five sections:

Section	Description	Page Numbers
A	**Summary** Rate Summary Table and Impact on 1,000 kWh Residential Bill.	2 - 5
B	**Allocation of the Rate Change** Tables showing how the overall retail rate change has been spread to the various retail rate classes.	6 - 7
C	**Proof of Revenue** A detailed demonstration of the revenue produced by the retail rates (excluding Rate Schedule OS), and associated back-up information. The style of this section is very similar to that of MFR E-13c.	8 - 24
D	**Proof of Revenue – Rate Schedule OS** A detailed demonstration of the revenue produced by Rate Schedule OS (Outdoor Service). The style of this section is very similar to that of MFR E-13d.	25 - 30
E	**Proof of Revenue Summary** A summary of revenue achieved for all new retail rates from Section C and Section D.	31 - 32

Section A
Summary

TAX REFORM
NEW RETAIL ELECTRIC SERVICE RATES
SUMMARY

Rate Schedule	Rate Component	Tax Reform Rates
RS	Base Charge ($/day)	$0.64
	Energy-Demand Charge (¢/KWH)	4.997 ¢
GS	Base Charge ($/Bill)	$26.00
	Energy-Demand Charge (¢/KWH)	5.126 ¢
GSD	Base Charge ($/Bill)	$47.33
	Demand Charge ($/KW)	$7.16
	Energy Charge (¢/KWH)	1.834 ¢
	Primary Voltage Discount	($0.28)
LP	Base Charge ($/Bill)	$262.80
	Demand Charge ($/KW)	$12.48
	Energy Charge (¢/KWH)	0.942 ¢
	Primary Voltage Discount	($0.37)
	Transmission Voltage Discount	($0.57)
PX	Base Charge ($/Bill)	$813.73
	Demand Charge ($/KW)	$11.87
	Energy Charge (¢/KWH)	0.436 ¢
	Minimum Monthly Bill	
	Demand Charge ($/KW)*	$14.26
	Transmission Voltage Discount	($0.18)
RSTOU	Base Charge ($/day)	$0.64
	On-Peak Energy-Demand Charge (¢/KWH)	4.997 ¢
	Off-Peak Energy-Demand Charge (¢/KWH)	4.997 ¢
RSVP	Base Charge ($/day)	$0.64
	Low P1 (¢/KWH)	4.997 ¢
	Medium P2 (¢/KWH)	4.997 ¢
	High P3 (¢/KWH)	4.997 ¢
	Critical P4 (¢/KWH)	4.997 ¢
GSTOU	Base Charge ($/Bill)	$47.33
	Summer On-Peak (¢/KWH)	19.732 ¢
	Summer Intermediate (¢/KWH)	7.366 ¢
	Summer Off-Peak (¢/KWH)	3.063 ¢
	Winter (¢/KWH)	4.287 ¢
GSDT	Base Charge ($/Bill)	$47.33
	Maximum Demand Charge ($/KW)	$3.40
	On-Peak Demand Charge ($/KW)	$3.83
	On-Peak Energy Charge (¢/KWH)	1.834 ¢
	Off-Peak Energy Charge (¢/KWH)	1.834 ¢
	Primary Voltage Discount	($0.28)

Rate Schedule	Rate Component	Tax Reform Rates
LPT	Base Charge ($/Bill)	$262.80
	Maximum Demand Charge ($/KW)	$2.55
	On-Peak Demand Charge ($/KW)	$10.03
	On-Peak Energy Charge (¢/KWH)	0.942 ¢
	Off-Peak Energy Charge (¢/KWH)	0.942 ¢
	Primary Voltage Discount	($0.37)
	Transmission Voltage Discount	($0.57)
	Critical Peak Option:	
	Max Demand ($/KW)	$2.55
	On-Peak Demand ($/KW)	$10.03
PXT	Base Charge ($/Bill)	$813.73
	Maximum Demand Charge ($/KW)	$0.97
	On-Peak Demand Charge ($/KW)	$11.02
	On-Peak Energy Charge (¢/KWH)	0.436 ¢
	Off-Peak Energy Charge (¢/KWH)	0.436 ¢
	Minimum Monthly Bill	
	Maximum Demand Charge ($/KW)*	$14.38
	Transmission Voltage Discount	($0.18)
OS-I/II	Energy Charge (¢/KWH)	2.558 ¢
OS-III	Energy Charge (¢/KWH)	4.821 ¢
SBS 100 to 499 KW	Base Charge ($/Bill)	$261.68
	Local Facilities Charge ($/KW)	$2.96
	Reservation Charge ($/KW)	$1.40
	Daily Demand Charge ($/KW)	$0.66
	On-Peak Demand Charge ($/KW)	$3.83
	Energy Charge (¢/KWH)	3.071 ¢
	Primary Voltage Discount	($0.05)
SBS 500 to 7,499 KW	Base Charge ($/Bill)	$261.68
	Local Facilities Charge ($/KW)	$2.70
	Reservation Charge ($/KW)	$1.40
	Daily Demand Charge ($/KW)	$0.66
	On-Peak Demand Charge ($/KW)	$10.03
	Energy Charge (¢/KWH)	3.071 ¢
	Primary Voltage Discount	($0.05)
	Transmission Voltage Discount	($0.06)
SBS Above 7,499 KW	Base Charge ($/Bill)	$623.10
	Local Facilities Charge ($/KW)	$0.94
	Reservation Charge ($/KW)	$1.43
	Daily Demand Charge ($/KW)	$0.67
	On-Peak Demand Charge ($/KW)	$11.02
	Energy Charge (¢/KWH)	3.071 ¢
	Transmission Voltage Discount	($0.07)

Gulf Power Company
Residential Service @ 1,000 kWh
Total Monthly Billing Base Rate Impact of Tax Reform
(Includes Clauses & GRT)

Billing Basis	Monthly Bill	Change
Present Rate	$ 144.00	
Proposed Rate	$ 141.81	$ (2.19)

Section B
Allocation of the Rate Change

TAX REFORM
ALLOCATION OF CHANGE

(1) RATE CLASS	(2) CHANGE FROM SERVICE CHARGES	(3) CHANGE FROM SALE OF ELECTRICITY	(4) CHANGE FROM OTHER REVENUE - UNBILLED	(5) TOTAL CHANGE	(6) % CHANGE
RESIDENTIAL	$0	($10,912,895)	($14,105)	($10,927,000)	-2.95%
GS	$0	($747,881)	($1,119)	($749,000)	-2.95%
GSD/GSDT	$0	($3,622,892)	($1,108)	($3,624,000)	-2.95%
LP/LPT	$0	($943,175)	$175	($943,000)	-2.95%
MAJOR ACCTS	$0	($1,369,000)	$0	($1,369,000)	-2.95%
OS	$0	($585,913)	($2,087)	($588,000)	-2.95%
TOTAL RETAIL:	$0	($18,181,756)	($18,244)	($18,200,000)	-2.95%

Section C
Proof of Revenue

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES RS, RSVP AND FLAT-RS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PRESENT REVENUE CALCULATION				PROPOSED REVENUE CALCULATION			
BASE CHARGE (CHG)	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
STANDARD RS:	4,432,780 BILLS @	$19.78 /BILL	$87,680,388	STANDARD RS:	4,432,780 BILLS @	$19.48 /BILL	$86,350,554
RSVP:	225,114 BILLS @	$19.78 /BILL	$4,452,755	RSVP:	225,114 BILLS @	$19.48 /BILL	$4,385,221
ENERGY/DEMAND CHG	KWH IN BLOCK			ENERGY/DEMAND CHG	KWH IN BLOCK		
STANDARD RS:	4,863,898,089 KWH @	$0.05181 /KWH	$251,998,560	STANDARD RS:	4,863,898,089 KWH @	$0.04997 /KWH	$243,048,988
RSVP: LOW	71,577,727 KWH @	$0.05181 /KWH	$3,708,442	RSVP: LOW	71,577,727 KWH @	$0.04997 /KWH	$3,576,739
RSVP: MEDIUM	199,092,749 KWH @	$0.05181 /KWH	$10,314,995	RSVP: MEDIUM	199,092,749 KWH @	$0.04997 /KWH	$9,948,665
RSVP: HIGH	45,333,662 KWH @	$0.05181 /KWH	$2,348,737	RSVP: HIGH	45,333,662 KWH @	$0.04997 /KWH	$2,265,323
RSVP: CRITICAL	329,619 KWH @	$0.05181 /KWH	$17,078	RSVP: CRITICAL	329,619 KWH @	$0.04997 /KWH	$16,471
FLAT-RS	139,057 Bills	153,216,169 KWH	$9,992,833	FLAT-RS	139,057 Bills	153,216,169 KWH	$9,992,833
		PRESENT BASE REVENUE:	$370,513,788			PROJECTED BASE REVENUE:	$359,584,794
						TOTAL CHANGE:	($10,928,994)
						% CHANGE:	-2.95%

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES GS AND FLAT-GS

(1)	(2)		(3)		(4)	(5)	(6)		(7)		(8)
PRESENT REVENUE CALCULATION						PROPOSED REVENUE CALCULATION					
BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
STANDARD GS:	371,168	BILLS @	$27.00	/BILL	$10,021,536	STANDARD GS:	371,168	BILLS @	$26.00	/BILL	$9,650,368
ENERGY/DEMAND CHG	KWH IN BLOCK					ENERGY/DEMAND CHG	KWH IN BLOCK				
STANDARD GS:	290,359,844	KWH @	$0.05256	/KWH	$15,261,313	STANDARD GS:	290,359,844	KWH @	$0.05126	/KWH	$14,883,846
FLAT-GS	1,344	Bills	1,528,629	KWH	$109,503	FLAT-GS	1,344	Bills	1,528,629	KWH	$109,503
			PRESENT BASE REVENUE :		$25,392,352				PROJECTED BASE REVENUE :		$24,643,717
									TOTAL CHANGE:		($748,635)
									% CHANGE:		-2.95%

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PRESENT REVENUE CALCULATION - GSD, GSDT, AND GSTOU				PROPOSED REVENUE CALCULATION - GSD, GSDT, AND GSTOU			
BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
STANDARD :	168,046 BILLS @	$48.10 /BILL	$8,083,013	STANDARD :	168,046 BILLS @	$47.33 /BILL	$7,953,617
TOU :	1,071 BILLS @	$48.10 /BILL	$51,515	TOU :	1,071 BILLS @	$47.33 /BILL	$50,690
GSTOU :	8,184 BILLS @	$48.10 /BILL	$393,650	GSTOU :	8,184 BILLS @	$47.33 /BILL	$387,349
DEMAND CHARGE	BILLING KW IN BLOCK			DEMAND CHARGE	BILLING KW IN BLOCK		
STANDARD :	7,801,902 KW @	$7.38 /KW	$57,578,037	STANDARD :	7,801,902 KW @	$7.16 /KW	$55,861,618
TOU : MAX DEMAND	88,787 KW @	$3.51 /KW	$311,642	TOU : MAX DEMAND	88,787 KW @	$3.40 /KW	$301,876
TOU : ON-PEAK	77,438 KW @	$3.95 /KW	$305,880	TOU : ON-PEAK	77,438 KW @	$3.83 /KW	$296,588
ENERGY CHARGE	KWH IN BLOCK			ENERGY CHARGE	KWH IN BLOCK		
STANDARD :	2,452,906,787 KWH @	$0.01894 /KWH	$46,458,055	STANDARD :	2,452,906,787 KWH @	$0.01834 /KWH	$44,986,310
TOU : ON-PEAK	6,599,972 KWH @	$0.01894 /KWH	$125,003	TOU : ON-PEAK	6,599,972 KWH @	$0.01834 /KWH	$121,043
TOU : OFF-PEAK	16,385,936 KWH @	$0.01894 /KWH	$310,350	TOU : OFF-PEAK	16,385,936 KWH @	$0.01834 /KWH	$300,518
TOU : SUM ON-PK	2,074,889 KWH @	$0.20342 /KWH	$422,074	TOU : SUM ON-PK	2,074,889 KWH @	$0.19732 /KWH	$409,417
TOU : SUM INTER	2,007,228 KWH @	$0.07594 /KWH	$152,429	TOU : SUM INTER	2,007,228 KWH @	$0.07366 /KWH	$147,852
TOU : SUM OFF-PK	9,353,686 KWH @	$0.03158 /KWH	$295,389	TOU : SUM OFF-PK	9,353,686 KWH @	$0.03063 /KWH	$286,503
TOU : WINTER	20,370,524 KWH @	$0.04420 /KWH	$900,377	TOU : WINTER	20,370,524 KWH @	$0.04287 /KWH	$873,284
REACTIVE CHARGE				REACTIVE CHARGE			
STANDARD :	52 KVARS @	$1.00 /KVAR	$52	STANDARD :	52 KVARS @	$1.00 /KVAR	$52
TOU :	--- KVARS @	--- /KVAR	---	TOU :	--- KVARS @	--- /KVAR	---
VOLTAGE DISCOUNTS				VOLTAGE DISCOUNTS			
STANDARD : PRIMARY	33,009 KW @	($0.30) /KW	($9,903)	STANDARD : PRIMARY	33,009 KW @	($0.28) /KW	($9,243)
	33,009 KW @	($0.07) /KW	($2,311)		33,009 KW @	($0.07) /KW	($2,311)
	11,444,701 KWH @	($0.00019) /KWH	($2,174)		11,444,701 KWH @	($0.00018) /KWH	($2,080)
	SUBTOTAL BASE REVENUE:		$115,373,078		SUBTOTAL BASE REVENUE:		$111,963,103

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

TRANSFERS TO RATE SCHEDULE GS FROM GSD - PRESENT REVENUE CALCULATION

(1)	(2)		(3)	(4)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	31,564	BILLS @	$27.00 /BILL	$852,228
TOU :	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	---	KW @	--- /KW	---
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	73,557,266	KWH @	$0.05256 /KWH	$3,866,170
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
VOLTAGE DISCOUNTS				
STANDARD : PRIMARY	---	KW @	--- /KW	---
	---	KW @	--- /KW	---
	---	KWH @	--- /KWH	---
			SUBTOTAL BASE REVENUE :	$4,718,398

TRANSFERS TO RATE SCHEDULE GS FROM GSD - PROPOSED REVENUE CALCULATION

(5)	(6)		(7)	(8)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	31,564	BILLS @	$26.00 /BILL	$820,664
TOU :	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	---	KW @	--- /KW	---
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY/DEMAND CHG	KWH IN BLOCK			
STANDARD :	73,557,266	KWH @	$0.05126 /KWH	$3,770,545
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
VOLTAGE DISCOUNTS				
STANDARD : PRIMARY	---	KW @	--- /KW	---
	---	KW @	--- /KW	---
	---	KWH @	--- /KWH	---
			SUBTOTAL BASE REVENUE :	$4,591,209

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

TRANSFERS TO RATE SCHEDULE LP FROM GSD - PRESENT REVENUE CALCULATION

(1)	(2)		(3)	(4)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	354	BILLS @	$262.80 /BILL	$93,031
TOU :	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	151,805	KW @	$12.87 /KW	$1,953,730
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	57,102,033	KWH @	$0.00972 /KWH	$555,032
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
VOLTAGE DISCOUNTS				
STANDARD : PRIMARY	4,928	KW @	($0.40) /KW	($1,971)
	4,928	KW @	($0.13) /KW	($641)
	1,215,255	KWH @	($0.00010) /KWH	($122)
			SUBTOTAL BASE REVENUE :	$2,599,059

TRANSFERS TO RATE SCHEDULE LP FROM GSD - PROPOSED REVENUE CALCULATION

(5)	(6)		(7)	(8)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	354	BILLS @	$262.80 /BILL	$93,031
TOU:	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	151,805	KW @	$12.48 /KW	$1,894,526
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	57,102,033	KWH @	$0.00942 /KWH	$537,901
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
VOLTAGE DISCOUNTS				
STANDARD : PRIMARY	4,928	KW @	($0.37) /KW	($1,823)
	4,928	KW @	($0.12) /KW	($591)
	1,215,255	KWH @	($0.00009) /KWH	($109)
			SUBTOTAL BASE REVENUE :	$2,522,935

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

TRANSFERS TO RATE SCHEDULE GSD FROM GSDT - PRESENT REVENUE CALCULATION

(1)	(2)		(3)	(4)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	117	BILLS @	$48.10 /BILL	$5,628
TOU :	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	18,542	KW @	$7.38 /KW	$136,840
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	8,843,555	KWH @	$0.01894 /KWH	$167,497
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
VOLTAGE DISCOUNTS				
STANDARD : PRIMARY	---	KW @	--- /KW	---
	---	KW @	--- /KW	---
	---	KWH @	--- /KWH	---
			SUBTOTAL BASE REVENUE :	$309,965

TRANSFERS TO RATE SCHEDULE GSD FROM GSDT - PROPOSED REVENUE CALCULATION

(5)	(6)		(7)	(8)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	117	BILLS @	$47.33 /BILL	$5,538
TOU:	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	18,542	KW @	$7.16 /KW	$132,761
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY/DEMAND CHARGE	KWH IN BLOCK			
STANDARD :	8,843,555	KWH @	$0.01834 /KWH	$162,191
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
VOLTAGE DISCOUNTS				
STANDARD : PRIMARY	---	KW @	--- /KW	---
	---	KW @	--- /KW	---
	---	KWH @	--- /KWH	---
			SUBTOTAL BASE REVENUE :	$300,490

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES GSD, GSDT, AND GSTOU

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	SUBTOTAL BASE REVENUE (PAGE 3 OF 14):		$115,373,078		SUBTOTAL BASE REVENUE (PAGE 3 OF 14):		$111,963,103
	SUBTOTAL BASE REVENUE (PAGE 4 OF 14):		$4,718,398		SUBTOTAL BASE REVENUE (PAGE 4 OF 14):		$4,591,209
	SUBTOTAL BASE REVENUE (PAGE 5 OF 14):		$2,599,059		SUBTOTAL BASE REVENUE (PAGE 5 OF 14):		$2,522,935
	SUBTOTAL BASE REVENUE (PAGE 6 OF 14):		$309,965		SUBTOTAL BASE REVENUE (PAGE 6 OF 14):		$300,490
		PRESENT BASE REVENUE:	$123,000,500			PROJECTED BASE REVENUE:	$119,377,737
						TOTAL CHANGE:	($3,622,763)
						% CHANGE:	-2.95%

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1)	(2)		(3)	(4)	(5)	(6)		(7)	(8)
PRESENT REVENUE CALCULATION - LP AND LPT					PROPOSED REVENUE CALCULATION - LP AND LPT				
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		o	CALCULATED REVENUES
STANDARD :	925	BILLS @	$262.80 /BILL	$243,090	STANDARD :	925	BILLS @	$262.80 /BILL	$243,090
TOU :	309	BILLS @	$262.80 /BILL	$81,205	TOU :	309	BILLS @	$262.80 /BILL	$81,205
TOU-CPO :	252	BILLS @	$262.80 /BILL	$66,226	TOU-CPO :	252	BILLS @	$262.80 /BILL	$66,226
DEMAND CHARGE	BILLING KW IN BLOCK				DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	638,399	KW @	$12.87 /KW	$8,216,195	STANDARD :	638,399	KW @	$12.48 /KW	$7,967,220
TOU : MAX DEMAND	318,190	KW @	$2.63 /KW	$836,840	TOU : MAX DEMAND	318,190	KW @	$2.55 /KW	$811,385
TOU : ON-PEAK	311,873	KW @	$10.34 /KW	$3,224,767	TOU : ON-PEAK	311,873	KW @	$10.03 /KW	$3,128,086
TOU-CPO : MAX DEMAND	120,247	KW @	$2.63 /KW	$316,250	TOU-CPO : MAX DEMAND	120,247	KW @	$2.55 /KW	$306,630
TOU-CPO : ON-PEAK	116,581	KW @	$10.34 /KW	$1,205,448	TOU-CPO : ON-PEAK	116,581	KW @	$10.03 /KW	$1,169,307
ENERGY CHARGE	KWH IN BLOCK				ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	258,455,767	KWH @	$0.00972 /KWH	$2,512,190	STANDARD :	258,455,767	KWH @	$0.00942 /KWH	$2,434,653
TOU : ON-PEAK	45,775,370	KWH @	$0.00972 /KWH	$444,937	TOU : ON-PEAK	45,775,370	KWH @	$0.00942 /KWH	$431,204
TOU : OFF-PEAK	123,885,986	KWH @	$0.00972 /KWH	$1,204,172	TOU : OFF-PEAK	123,885,986	KWH @	$0.00942 /KWH	$1,167,006
TOU-CPO : ON-PEAK	16,514,412	KWH @	$0.00972 /KWH	$160,520	TOU-CPO : ON-PEAK	16,514,412	KWH @	$0.00942 /KWH	$155,566
TOU-CPO : OFF-PEAK	44,979,991	KWH @	$0.00972 /KWH	$437,206	TOU-CPO : OFF-PEAK	44,979,991	KWH @	$0.00942 /KWH	$423,712
REACTIVE CHARGE					REACTIVE CHARGE				
STANDARD :	31,155	KVARS @	$1.00 /KVAR	$31,155	STANDARD :	31,155	KVARS @	$1.00 /KVAR	$31,155
TOU :	24,105	KVARS @	$1.00 /KVAR	$24,105	TOU :	24,105	KVARS @	$1.00 /KVAR	$24,105
TOU-CPO :	8,604	KVARS @	$1.00 /KVAR	$8,604	TOU-CPO :	8,604	KVARS @	$1.00 /KVAR	$8,604
VOLTAGE DISCOUNTS					VOLTAGE DISCOUNTS				
STANDARD : PRI	174,321	KW @	($0.40) /KW	($69,728)	STANDARD : PRI	174,321	KW @	($0.37) /KW	($64,499)
	174,321	KW @	($0.13) /KW	($22,662)		174,321	KW @	($0.12) /KW	($20,919)
	79,597,148	KWH @	($0.00010) /KWH	($7,960)		79,597,148	KWH @	($0.00009) /KWH	($7,164)
TOU : PRIMARY	94,882	MAX KW @	($0.40) /KW	($37,953)	TOU : PRIMARY	94,882	MAX KW @	($0.37) /KW	($35,106)
	94,882	MAX KW @	($0.03) /KW	($2,846)		94,882	MAX KW @	($0.03) /KW	($2,846)
	94,081	ON-PK KW @	($0.10) /KW	($9,408)		94,081	ON-PK KW @	($0.10) /KW	($9,408)
	14,061,156	ON-PK KWH @	($0.00010) /KWH	($1,406)		14,061,156	ON-PK KWH @	($0.00009) /KWH	($1,266)
	37,209,462	OFF-PK KWH @	($0.00010) /KWH	($3,721)		37,209,462	OFF-PK KWH @	($0.00009) /KWH	($3,349)
TOU-CPO : PRIMARY	14,740	MAX KW @	($0.40) /KW	($5,896)	TOU-CPO : PRIMARY	14,740	MAX KW @	($0.37) /KW	($5,454)
	14,740	MAX KW @	($0.03) /KW	($442)		14,740	MAX KW @	($0.03) /KW	($442)
	14,526	ON-PK KW @	($0.10) /KW	($1,453)		14,526	ON-PK KW @	($0.10) /KW	($1,453)
	1,782,649	ON-PK KWH @	($0.00010) /KWH	($178)		1,782,649	ON-PK KWH @	($0.00009) /KWH	($160)
	4,717,351	OFF-PK KWH @	($0.00010) /KWH	($472)		4,717,351	OFF-PK KWH @	($0.00009) /KWH	($425)
			SUBTOTAL BASE REVENUE :	$18,848,785				SUBTOTAL BASE REVENUE :	$18,296,663

Case No.: U-20134
Exhibit No.: A-98 (SM-7)
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Witness: SMaddipati
Date: May 2018

Attachment A
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TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
TRANSFERS TO RATE SCHEDULE GSD FROM LP - PRESENT REVENUE CALCULATION				TRANSFERS TO RATE SCHEDULE GSD FROM LP - PROPOSED REVENUE CALCULATION			
BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES	BASE CHARGE	NUMBER OF BILLS		CALCULATED REVENUES
STANDARD :	575 BILLS @	$48.10 /BILL	$27,658	STANDARD :	575 BILLS @	$47.33 /BILL	$27,215
TOU :	--- BILLS @	--- /BILL	---	TOU:	--- BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			DEMAND CHARGE	BILLING KW IN BLOCK		
STANDARD :	185,822 KW @	$7.38 /KW	$1,371,366	STANDARD :	185,822 KW @	$7.16 /KW	$1,330,486
TOU : MAX DEMAND	--- KW @	--- /KW	---	TOU : MAX DEMAND	--- KW @	--- /KW	---
TOU : ON-PEAK	--- KW @	--- /KW	---	TOU : ON-PEAK	--- KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			ENERGY CHARGE	KWH IN BLOCK		
STANDARD :	86,844,865 KWH @	$0.01894 /KWH	$1,644,842	STANDARD :	86,844,865 KWH @	$0.01834 /KWH	$1,592,735
TOU : ON-PEAK	--- KWH @	--- /KWH	---	TOU : ON-PEAK	--- KWH @	--- /KWH	---
TOU : OFF-PEAK	--- KWH @	--- /KWH	---	TOU : OFF-PEAK	--- KWH @	--- /KWH	---
REACTIVE CHARGE				REACTIVE CHARGE			
STANDARD :	10,390 KVARS @	$1.00 /KVAR	$10,390	STANDARD :	10,390 KVARS @	$1.00 /KVAR	$10,390
TOU :	--- KVARS @	--- /KVAR	---	TOU :	--- KVARS @	--- /KVAR	---
VOLTAGE DISCOUNTS				VOLTAGE DISCOUNTS			
STANDARD : PRIMARY	6,484 KW @	($0.30) /KW	($1,945)	STANDARD : PRIMARY	6,484 KW @	($0.28) /KW	($1,816)
	6,484 KW @	($0.07) /KW	($454)		6,484 KW @	($0.07) /KW	($454)
	3,244,309 KWH @	($0.00019) /KWH	($616)		3,244,309 KWH @	($0.00018) /KWH	($584)
		SUBTOTAL BASE REVENUE :	$3,051,241			SUBTOTAL BASE REVENUE :	$2,957,972

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

TRANSFERS TO RATE SCHEDULE LP FROM LPT - PRESENT REVENUE CALCULATION

(1)	(2)		(3)	(4)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	100	BILLS @	$262.80 /BILL	$26,280
TOU :	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	462,316	KW @	$12.87 /KW	$5,950,007
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	254,225,155	KWH @	$0.00972 /KWH	$2,471,069
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
REACTIVE CHARGE				
STANDARD :	5,520	KVARS @	$1.00 /KVAR	$5,520
TOU :	---	KVARS @	--- /KVAR	---
VOLTAGE DISCOUNTS				
STANDARD : PRI	426,295	KW @	($0.40) /KW	($170,518)
	426,295	KW @	($0.13) /KW	($55,418)
	233,029,811	KWH @	($0.00010) /KWH	($23,303)
TOU : PRI	---	MAX KW @	($0.40) /KW	---
	---	MAX KW @	($0.03) /KW	---
	---	ON-PK KW @	($0.10) /KW	---
	---	ON-PK KWH @	($0.00010) /KWH	---
	---	OFF-PK KWH @	($0.00010) /KWH	---
			SUBTOTAL BASE REVENUE :	$8,203,637

TRANSFERS TO RATE SCHEDULE LP FROM LPT - PROPOSED REVENUE CALCULATION

(5)	(6)		(7)	(8)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	100	BILLS @	$262.80 /BILL	$26,280
TOU:	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	462,316	KW @	$12.48 /KW	$5,769,704
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	254,225,155	KWH @	$0.00942 /KWH	$2,394,801
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
REACTIVE CHARGE				
STANDARD :	5,520	KVARS @	$1.00 /KVAR	$5,520
TOU :	---	KVARS @	--- /KVAR	---
VOLTAGE DISCOUNTS				
STANDARD : PRI	426,295	KW @	($0.37) /KW	($157,729)
	426,295	KW @	($0.12) /KW	($51,155)
	233,029,811	KWH @	($0.00009) /KWH	($20,973)
TOU : PRI	---	MAX KW @	($0.37) /KW	---
	---	MAX KW @	($0.03) /KW	---
	---	ON-PK KW @	($0.10) /KW	---
	---	ON-PK KWH @	($0.00009) /KWH	---
	---	OFF-PK KWH @	($0.00009) /KWH	---
			SUBTOTAL BASE REVENUE :	$7,966,448

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

TRANSFERS TO RATE SCHEDULE GSD FROM LPT - PRESENT REVENUE CALCULATION

(1)	(2)		(3)	(4)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	194	BILLS @	$48.10 /BILL	$9,331
TOU :	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	67,550	KW @	$7.38 /KW	$498,519
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	36,554,859	KWH @	$0.01894 /KWH	$692,349
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
REACTIVE CHARGE				
STANDARD :	3,509	KVARS @	$1.00 /KVAR	$3,509
TOU :	---	KVARS @	--- /KVAR	---
VOLTAGE DISCOUNTS				
STANDARD : PRI	5,191	KW @	($0.30) /KW	($1,557)
	5,191	KW @	($0.07) /KW	($363)
	2,269,715	KWH @	($0.00019) /KWH	($431)
TOU : PRI	---	MAX KW @	--- /KW	---
	---	MAX KW @	--- /KW	---
	---	ON-PK KW @	--- /KW	---
	---	ON-PK KWH @	--- /KWH	---
	---	OFF-PK KWH @	--- /KWH	---
			SUBTOTAL BASE REVENUE :	$1,201,357

TRANSFERS TO RATE SCHEDULE GSD FROM LPT - PROPOSED REVENUE CALCULATION

(5)	(6)		(7)	(8)
BASE CHARGE	NUMBER OF BILLS			CALCULATED REVENUES
STANDARD :	194	BILLS @	$47.33 /BILL	$9,182
TOU:	---	BILLS @	--- /BILL	---
DEMAND CHARGE	BILLING KW IN BLOCK			
STANDARD :	67,550	KW @	$7.16 /KW	$483,658
TOU : MAX DEMAND	---	KW @	--- /KW	---
TOU : ON-PEAK	---	KW @	--- /KW	---
ENERGY CHARGE	KWH IN BLOCK			
STANDARD :	36,554,859	KWH @	$0.01834 /KWH	$670,416
TOU : ON-PEAK	---	KWH @	--- /KWH	---
TOU : OFF-PEAK	---	KWH @	--- /KWH	---
REACTIVE CHARGE				
STANDARD :	3,509	KVARS @	$1.00 /KVAR	$3,509
TOU :	---	KVARS @	--- /KVAR	---
VOLTAGE DISCOUNTS				
STANDARD : PRI	5,191	KW @	($0.28) /KW	($1,453)
	5,191	KW @	($0.07) /KW	($363)
	2,269,715	KWH @	($0.00018) /KWH	($409)
TOU : PRI	---	MAX KW @	--- /KW	---
	---	MAX KW @	--- /KW	---
	---	ON-PK KW @	--- /KW	---
	---	ON-PK KWH @	--- /KWH	---
	---	OFF-PK KWH @	--- /KWH	---
			SUBTOTAL BASE REVENUE :	$1,164,540

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

TRANSFERS TO RATE SCHEDULE GSDT FROM LPT - PRESENT REVENUE CALCULATION

(1)	(2)		(3)		(4)
BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
STANDARD :	---	BILLS @	---	/BILL	---
TOU :	117	BILLS @	$48.10	/BILL	$5,628
DEMAND CHARGE					
STANDARD :	---	KW @	---	/KW	---
TOU : MAX DEMAND	41,375	KW @	$3.51	/KW	$145,226
TOU : ON-PEAK	40,353	KW @	$3.95	/KW	$159,394
ENERGY CHARGE					
STANDARD :	---	KWH @	---	/KWH	---
TOU : ON-PEAK	5,518,189	KWH @	$0.01894	/KWH	$104,514
TOU : OFF-PEAK	15,081,485	KWH @	$0.01894	/KWH	$285,643
REACTIVE CHARGE					
STANDARD :	---	KVARS @	---	/KVAR	---
TOU :	342	KVARS @	$1.00	/KVAR	$342
			SUBTOTAL BASE REVENUE :		$700,747

TRANSFERS TO RATE SCHEDULE GSDT FROM LPT - PROPOSED REVENUE CALCULATION

(5)	(6)		(7)		(8)
BASE CHARGE	NUMBER OF BILLS				CALCULATED REVENUES
STANDARD :	---	BILLS @	---	/BILL	---
TOU:	117	BILLS @	$47.33	/BILL	$5,538
DEMAND CHARGE	BILLING KW IN BLOCK				
STANDARD :	---	KW @	---	/KW	---
TOU : MAX DEMAND	41,375	KW @	$3.40	/KW	$140,675
TOU : ON-PEAK	40,353	KW @	$3.83	/KW	$154,552
ENERGY CHARGE	KWH IN BLOCK				
STANDARD :	---	KWH @	---	/KWH	---
TOU : ON-PEAK	5,518,189	KWH @	0.01834	/KWH	$101,204
TOU : OFF-PEAK	15,081,485	KWH @	0.01834	/KWH	$276,594
REACTIVE CHARGE					
STANDARD :	---	KVARS @	---	/KVAR	---
TOU :	342	KVARS @	$1.00	/KVAR	$342
			SUBTOTAL BASE REVENUE :		$678,905

TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES LP AND LPT

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	SUBTOTAL BASE REVENUE (PAGE 8 OF 14):		$18,848,785		SUBTOTAL BASE REVENUE (PAGE 8 OF 14):		$18,296,663
	SUBTOTAL BASE REVENUE (PAGE 9 OF 14):		$3,051,241		SUBTOTAL BASE REVENUE (PAGE 9 OF 14):		$2,957,972
	SUBTOTAL BASE REVENUE (PAGE 10 OF 14):		$8,203,637		SUBTOTAL BASE REVENUE (PAGE 10 OF 14):		$7,966,448
	SUBTOTAL BASE REVENUE (PAGE 11 OF 14):		$1,201,357		SUBTOTAL BASE REVENUE (PAGE 11 OF 14):		$1,164,540
	SUBTOTAL BASE REVENUE (PAGE 12 OF 14):		$700,747		SUBTOTAL BASE REVENUE (PAGE 12 OF 14):		$678,905
		PRESENT BASE REVENUE:	$32,005,767			PROJECTED BASE REVENUE:	$31,064,528
						TOTAL CHANGE:	($941,239)
						% CHANGE:	-2.94%

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Attachment A
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TAX REFORM
GULF POWER COMPANY
PROOF OF REVENUE AND RATE MIGRATIONS
BY RATE CLASS

REVENUE CALCULATION FOR RATE SCHEDULES SBS, RTP AND CIS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PRESENT REVENUE CALCULATION - SBS, RTP, AND CIS				PROPOSED REVENUE CALCULATION - SBS, RTP, AND CIS			
			CALCULATED REVENUES				CALCULATED REVENUES
SBS BASE CHARGE	NUMBER OF BILLS			SBS BASE CHARGE	NUMBER OF BILLS		
	24 BILLS @	$261.68 /BILL	$6,280		24 BILLS @	$261.68 /BILL	$6,280
	12 BILLS @	$623.10 /BILL	$7,477		12 BILLS @	$623.10 /BILL	$7,477
SBS LOCAL FAC CHG	BILLING KW IN BLOCK			SBS LOCAL FAC CHG	BILLING KW IN BLOCK		
	59,015 KW @	$2.79 /KW	$164,652		59,015 KW @	$2.70 /KW	$159,341
	751,200 KW @	$0.96 /KW	$721,152		751,200 KW @	$0.94 /KW	$706,128
SBS RESERV CHG	BILLING KW IN BLOCK			SBS RESERV CHG	BILLING KW IN BLOCK		
	59,015 KW @	$1.44 /KW	$84,982		59,015 KW @	$1.40 /KW	$82,621
	751,200 KW @	$1.47 /KW	$1,104,264		751,200 KW @	$1.43 /KW	$1,074,216
SBS DAILY DEMAND	BILLING KW IN BLOCK			SBS DAILY DEMAND	BILLING KW IN BLOCK		
	--- KW @	$0.68 /KW	---		--- KW @	$0.66 /KW	---
	--- KW @	$0.69 /KW	---		--- KW @	$0.67 /KW	---
SBS ENERGY CHARGE	KWH IN BLOCK			SBS ENERGY CHARGE	KWH IN BLOCK		
ON-PEAK	685,071 KWH @	$0.03225 /KWH	$22,094	ON-PEAK	685,071 KWH @	$0.03071 /KWH	$21,039
OFF-PEAK	3,574,201 KWH @	$0.03225 /KWH	$115,268	OFF-PEAK	3,574,201 KWH @	$0.03071 /KWH	$109,764
ON-PEAK	2,628,372 KWH @	$0.03225 /KWH	$84,765	ON-PEAK	2,628,372 KWH @	$0.03071 /KWH	$80,717
OFF-PEAK	5,015,628 KWH @	$0.03225 /KWH	$161,754	OFF-PEAK	5,015,628 KWH @	$0.03071 /KWH	$154,030
SBS VOLTAGE DISCOUNT - TRANSMISSION				SBS VOLTAGE DISCOUNT - TRANSMISSION			
59,015	LFC KW @	($0.06) /KW =	($3,541)	59,015	LFC KW @	($0.06) /KW =	($3,645)
59,015	LFC KW @	($0.06) /KW =	($3,541)	59,015	LFC KW @	($0.05) /KW =	($2,951)
59,015	RC KW @	($0.03) /KW =	($1,770)	59,015	RC KW @	($0.03) /KW =	($1,770)
685,071	ON-PEAK @	($0.00065) /KWH =	($445)	685,071	ON-PEAK @	($0.00061) /KWH =	($418)
3,574,201	OFF-PEAK @	($0.00065) /KWH =	($2,323)	3,574,201	OFF-PEAK @	($0.00061) /KWH =	($2,180)
		SUBTOTAL BASE REVENUE:	$2,461,068			SUBTOTAL PROJECTED BASE REVENUE:	$2,390,649
RTP	1,524 Bills	1,643,584,389 KWH	$42,805,283	RTP	1,524 Bills	1,643,584,389 KWH	$41,506,851
CIS	12 Bills	49,000,000 KWH	$1,207,761	CIS	12 Bills	49,000,000 KWH	$1,207,761
		PRESENT BASE REVENUE:	$46,474,112			PROJECTED BASE REVENUE:	$45,105,261
						TOTAL CHANGE:	($1,368,851)
						% CHANGE:	-2.95%

TAX REFORM
BASE CHARGE CHANGES AND CORRESPONDING UNIT COSTS

(1) RATE CLASS	(2) CURRENT BASE CHARGE	(3) NEW BASE CHARGE TAX REFORM	(4) UNIT COST
RESIDENTIAL	$0.65 /day	$0.64 /day(1)	$19.56 /mo.
GS	$27.00 /mo.	$26.00 /mo.	$26.55 /mo.
GSD/GSDT	$48.10 /mo.	$47.33 /mo.	$47.45 /mo.
PX/PXT	$838.43 /mo.	$813.73 /mo.	No Data: Billing Units = 0

(1)Converting the Residential Base Charge to an average monthly value using 30.4375 days per month yields $19.48 per month

TAX REFORM
TRANSFORMER DISCOUNTS AND UNIT COSTS

A	B	C	D
Rate Schedule and Voltage Level	Contract Level	Gulf's Current Discount* ($/KW/MO)	Tax Reform Unit Cost ($/KW/MO)
GSD/GSDT - Primary	N/A	$0.30	$0.28
LP/LPT - Primary	N/A	$0.40	$0.37
LP/LPT - Transmission	N/A	$0.61	$0.57
PX/PXT - Transmission	N/A	$0.18	$0.18
SBS - Primary	1 - 499 KW	$0.05	$0.05
SBS - Primary	500 - 7,499 KW	$0.05	$0.05
SBS - Transmission	500 - 7,499 KW	$0.06	$0.06
SBS - Transmission	7,500 KW - above	$0.07	$0.07

*Prepared using methodology specified by the FPSC's final orders in Gulf's last three rate cases.

Section D
Proof of Revenue
Rate Schedule OS

TAX REFORM
GULF POWER COMPANY
RATE SCHEDULE OS

(1) Type of Facility	(2) Description	(3) Annual Billing Items	(4) Est. Monthly KWH	(5) Annual KWH	(6) Present Rates: Facility Charge	(7) Present Rates: Maintenance Charge	(8) Present Rates: Energy Charge	(9) Present Rates: Total Monthly Charge	(10) Present Rates: $ Total Revenue	(11) Proposed Rates: Facility Charge	(12) Proposed Rates: Maintenance Charge	(13) Proposed Rates: Energy Charge	(14) Proposed Rates: Total Monthly Charge	(15) Proposed Rates: $ Total Revenue	(16) Percent Change
HIGH PRESSURE SODIUM VAPOR (OS-I/II)															
5400 LUMEN	Open Bottom	1,524	29	44,196	$3.31	$1.79	$0.76	$5.86	$8,930.64	$3.21	$1.74	$0.74	$5.69	$8,671.56	-2.90%
8800 LUMEN	Open Bottom	540,384	41	22,155,744	$2.84	$1.62	$1.08	$5.54	$2,993,727.36	$2.76	$1.57	$1.05	$5.38	$2,907,265.92	-2.89%
8800 LUMEN	Open Bottom w/Shield	168	41	6,888	$3.89	$1.90	$1.08	$6.87	$1,154.16	$3.77	$1.84	$1.05	$6.66	$1,118.88	-3.06%
8800 LUMEN	Acorn	35,640	41	1,461,240	$14.14	$4.77	$1.08	$19.99	$712,443.60	$13.72	$4.63	$1.05	$19.40	$691,416.00	-2.95%
8800 LUMEN	Colonial	33,048	41	1,354,968	$3.81	$1.88	$1.08	$6.77	$223,734.96	$3.70	$1.82	$1.05	$6.57	$217,125.36	-2.95%
8800 LUMEN	English Coach	888	41	36,408	$15.43	$5.12	$1.08	$21.63	$19,207.44	$14.97	$4.97	$1.05	$20.99	$18,639.12	-2.96%
8800 LUMEN	Destin Single	852	41	34,932	$26.55	$8.24	$1.08	$35.87	$30,561.24	$25.77	$8.00	$1.05	$34.82	$29,666.64	-2.93%
17600 LUMEN	Destin Double	12	82	984	$52.94	$15.88	$2.16	$70.98	$851.76	$51.37	$15.41	$2.10	$68.88	$826.56	-2.96%
5400 LUMEN	Cobrahead	1,668	29	48,372	$4.65	$2.15	$0.76	$7.56	$12,610.08	$4.51	$2.09	$0.74	$7.34	$12,243.12	-2.91%
8800 LUMEN	Cobrahead	307,524	41	12,608,484	$3.89	$1.90	$1.08	$6.87	$2,112,689.88	$3.77	$1.84	$1.05	$6.66	$2,048,109.84	-3.06%
20000 LUMEN	Cobrahead	28,248	80	2,259,840	$5.36	$2.34	$2.11	$9.81	$277,112.88	$5.20	$2.27	$2.05	$9.52	$268,920.96	-2.96%
25000 LUMEN	Cobrahead	19,632	100	1,963,200	$5.21	$2.30	$2.64	$10.15	$199,264.80	$5.06	$2.23	$2.56	$9.85	$193,375.20	-2.96%
46000 LUMEN	Cobrahead	19,548	164	3,205,872	$5.48	$2.37	$4.32	$12.17	$237,899.16	$5.32	$2.30	$4.20	$11.82	$231,057.36	-2.88%
8800 LUMEN	Cut-Off Cobrahead	13,008	41	533,328	$4.30	$2.01	$1.08	$7.39	$96,129.12	$4.17	$1.95	$1.05	$7.17	$93,267.36	-2.98%
25000 LUMEN	Cut-Off Cobrahead	4,524	100	452,400	$5.28	$2.32	$2.64	$10.24	$46,325.76	$5.12	$2.25	$2.56	$9.93	$44,923.32	-3.03%
46000 LUMEN	Cut-Off Cobrahead	552	164	90,528	$5.50	$2.37	$4.32	$12.19	$6,728.88	$5.34	$2.30	$4.20	$11.84	$6,535.68	-2.87%
25000 LUMEN	Bracket Mount CIS	396	100	39,600	$12.08	$4.22	$2.64	$18.94	$7,500.24	$11.72	$4.10	$2.56	$18.38	$7,278.48	-2.96%
25000 LUMEN	Tenon Top CIS	36	100	3,600	$12.09	$4.22	$2.64	$18.95	$682.20	$11.73	$4.10	$2.56	$18.39	$662.04	-2.96%
46000 LUMEN	Bracket Mount CIS	420	161	67,620	$12.86	$4.42	$4.24	$21.52	$9,038.40	$12.48	$4.29	$4.12	$20.89	$8,773.80	-2.93%
25000 LUMEN	Small ORL	456	100	45,600	$11.91	$4.16	$2.64	$18.71	$8,531.76	$11.56	$4.04	$2.56	$18.16	$8,280.96	-2.94%
46000 LUMEN	Small ORL	948	164	155,472	$12.46	$4.32	$4.32	$21.10	$20,002.80	$12.09	$4.19	$4.20	$20.48	$19,415.04	-2.94%
20000 LUMEN	Large ORL	3,120	80	249,600	$20.16	$6.45	$2.11	$28.72	$89,606.40	$19.56	$6.26	$2.05	$27.87	$86,954.40	-2.96%
46000 LUMEN	Large ORL	360	164	59,040	$22.70	$7.17	$4.32	$34.19	$12,308.40	$22.03	$6.96	$4.20	$33.19	$11,948.40	-2.92%
46000 LUMEN	Shoebox	876	164	143,664	$10.41	$3.74	$4.32	$18.47	$16,179.72	$10.10	$3.63	$4.20	$17.93	$15,706.68	-2.92%
16000 LUMEN	Directional	1,464	68	99,552	$5.85	$2.43	$1.79	$10.07	$14,742.48	$5.68	$2.36	$1.74	$9.78	$14,317.92	-2.88%
20000 LUMEN	Directional	1,704	80	136,320	$8.45	$3.21	$2.11	$13.77	$23,464.08	$8.20	$3.12	$2.05	$13.37	$22,782.48	-2.90%
46000 LUMEN	Directional	112,776	164	18,495,264	$6.28	$2.60	$4.32	$13.20	$1,488,643.20	$6.09	$2.52	$4.20	$12.81	$1,444,660.56	-2.95%
125000 LUMEN	Large Flood	396	379	150,084	$9.96	$3.82	$9.99	$23.77	$9,412.92	$9.67	$3.71	$9.69	$23.07	$9,135.72	-2.94%
HIGH PRESSURE SODIUM VAPOR (OS-I/II) - PAID UP FRONT															
8800 LUMEN	Open Bottom PUF	2,712	41	111,192	N/A	$1.62	$1.08	$2.70	$7,322.40	N/A	$1.57	$1.05	$2.62	$7,105.44	-2.96%
8800 LUMEN	Acorn PUF	11,016	41	451,656	N/A	$4.77	$1.08	$5.85	$64,443.60	N/A	$4.63	$1.05	$5.68	$62,570.88	-2.91%
8800 LUMEN	Colonial PUF	8,496	41	348,336	N/A	$1.88	$1.08	$2.96	$25,148.16	N/A	$1.82	$1.05	$2.87	$24,383.52	-3.04%
8800 LUMEN	English Coach PUF	540	41	22,140	N/A	$5.12	$1.08	$6.20	$3,348.00	N/A	$4.97	$1.05	$6.02	$3,250.80	-2.90%
8800 LUMEN	Destin Single PUF	804	41	32,964	N/A	$8.24	$1.08	$9.32	$7,493.28	N/A	$8.00	$1.05	$9.05	$7,276.20	-2.90%
8800 LUMEN	Cobrahead PUF	17,544	41	719,304	N/A	$1.90	$1.08	$2.98	$52,281.12	N/A	$1.84	$1.05	$2.89	$50,702.16	-3.02%
16000 LUMEN	Directional PUF	24	68	1,632	N/A	$2.43	$1.79	$4.22	$101.28	N/A	$2.36	$1.74	$4.10	$98.40	-2.84%
17600 LUMEN	Destin Double PUF	24	82	1,968	N/A	$15.88	$2.16	$18.04	$432.96	N/A	$15.41	$2.10	$17.51	$420.24	-2.94%
20000 LUMEN	Cobrahead PUF	2,904	80	232,320	N/A	$2.34	$2.11	$4.45	$12,922.80	N/A	$2.27	$2.05	$4.32	$12,545.28	-2.92%
25000 LUMEN	Cobrahead PUF	5,652	100	565,200	N/A	$2.30	$2.64	$4.94	$27,920.88	N/A	$2.23	$2.56	$4.79	$27,073.08	-3.04%

TAX REFORM
GULF POWER COMPANY
RATE SCHEDULE OS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
					Present Rates					Proposed Rates					
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Change
HIGH PRESSURE SODIUM VAPOR (OS-I/II) - PAID UP FRONT (Cont.)															
46000 LUMEN	Bracket Mount CIS PUF	192	161	30,912	N/A	$4.42	$4.24	$8.66	$1,662.72	N/A	$4.29	$4.12	$8.41	$1,614.72	-2.89%
46000 LUMEN	Cobrahead PUF	2,244	164	368,016	N/A	$2.37	$4.32	$6.69	$15,012.36	N/A	$2.30	$4.20	$6.50	$14,586.00	-2.84%
8800 LUMEN	Cut-Off Cobrahead PUF	1,416	41	58,056	N/A	$2.01	$1.08	$3.09	$4,375.44	N/A	$1.95	$1.05	$3.00	$4,248.00	-2.91%
25000 LUMEN	Cut-Off Cobrahead PUF	1,944	100	194,400	N/A	$2.32	$2.64	$4.96	$9,642.24	N/A	$2.25	$2.56	$4.81	$9,350.64	-3.02%
46000 LUMEN	Cut-Off Cobrahead PUF	132	164	21,648	N/A	$2.37	$4.32	$6.69	$883.08	N/A	$2.30	$4.20	$6.50	$858.00	-2.84%
25000 LUMEN	Bracket Mount CIS PUF	1,680	100	168,000	N/A	$4.22	$2.64	$6.86	$11,524.80	N/A	$4.10	$2.56	$6.66	$11,188.80	-2.92%
25000 LUMEN	Tenon Top CIS PUF	636	100	63,600	N/A	$4.22	$2.64	$6.86	$4,362.96	N/A	$4.10	$2.56	$6.66	$4,235.76	-2.92%
25000 LUMEN	Small ORL PUF	192	100	19,200	N/A	$4.16	$2.64	$6.80	$1,305.60	N/A	$4.04	$2.56	$6.60	$1,267.20	-2.94%
46000 LUMEN	Shoebox PUF	816	164	133,824	N/A	$3.74	$4.32	$8.06	$6,576.96	N/A	$3.63	$4.20	$7.83	$6,389.28	-2.85%
46000 LUMEN	Directional PUF	1,176	164	192,864	N/A	$2.60	$4.32	$6.92	$8,137.92	N/A	$2.52	$4.20	$6.72	$7,902.72	-2.89%
METAL HALIDE (OS-I/II)															
12000 LUMEN	Acorn	804	72	57,888	$14.28	$6.00	$1.90	$22.18	$17,832.72	$13.86	$5.82	$1.84	$21.52	$17,302.08	-2.98%
12000 LUMEN	Colonial	1,440	72	103,680	$3.95	$3.14	$1.90	$8.99	$12,945.60	$3.83	$3.05	$1.84	$8.72	$12,556.80	-3.00%
12000 LUMEN	Destin Single	24	72	1,728	$26.69	$9.47	$1.90	$38.06	$913.44	$25.90	$9.19	$1.84	$36.93	$886.32	-2.97%
32000 LUMEN	Small Flood	23,976	163	3,908,088	$6.42	$2.77	$4.30	$13.49	$323,436.24	$6.23	$2.69	$4.17	$13.09	$313,845.84	-2.97%
32000 LUMEN	Small Parking Lot	2,892	163	471,396	$11.85	$4.30	$4.30	$20.45	$59,141.40	$11.50	$4.17	$4.17	$19.84	$57,377.28	-2.98%
100000 LUMEN	Large Flood	21,000	378	7,938,000	$9.20	$5.50	$9.96	$24.66	$517,860.00	$8.93	$5.34	$9.67	$23.94	$502,740.00	-2.92%
100000 LUMEN	Large Parking Lot	1,212	378	458,136	$20.45	$7.63	$9.96	$38.04	$46,104.48	$19.85	$7.40	$9.67	$36.92	$44,747.04	-2.94%
METAL HALIDE (OS-I/II) - PAID UP FRONT															
12000 LUMEN	Acorn PUF	636	72	45,792	N/A	$6.00	$1.90	$7.90	$5,024.40	N/A	$5.82	$1.84	$7.66	$4,871.76	-3.04%
12000 LUMEN	Colonial PUF	72	72	5,184	N/A	$3.14	$1.90	$5.04	$362.88	N/A	$3.05	$1.84	$4.89	$352.08	-2.98%
12000 LUMEN	Destin Single PUF	528	72	38,016	N/A	$9.47	$1.90	$11.37	$6,003.36	N/A	$9.19	$1.84	$11.03	$5,823.84	-2.99%
24000 LUMEN	Destin Double PUF	60	144	8,640	N/A	$17.72	$3.80	$21.52	$1,291.20	N/A	$17.20	$3.68	$20.88	$1,252.80	-2.97%
32000 LUMEN	Small Flood PUF	276	163	44,988	N/A	$2.77	$4.30	$7.07	$1,951.32	N/A	$2.69	$4.17	$6.86	$1,893.36	-2.97%
32000 LUMEN	Small Parking Lot PUF	348	163	56,724	N/A	$4.30	$4.30	$8.60	$2,992.80	N/A	$4.17	$4.17	$8.34	$2,902.32	-3.02%
100000 LUMEN	Large Flood PUF	780	378	294,840	N/A	$5.50	$9.96	$15.46	$12,058.80	N/A	$5.34	$9.67	$15.01	$11,707.80	-2.91%
100000 LUMEN	Large Parking Lot PUF	96	378	36,288	N/A	$7.63	$9.96	$17.59	$1,688.64	N/A	$7.40	$9.67	$17.07	$1,638.72	-2.96%
METAL HALIDE PULSE START (OS-I/II)															
13000 LUMEN	Acorn PS	1,332	65	86,580	$16.20	$5.84	$1.71	$23.75	$31,635.00	$15.72	$5.67	$1.66	$23.05	$30,702.60	-2.95%
13000 LUMEN	Colonial PS	3,300	65	214,500	$5.04	$2.74	$1.71	$9.49	$31,317.00	$4.89	$2.66	$1.66	$9.21	$30,393.00	-2.95%
13000 LUMEN	Destin Single PS	132	65	8,580	$35.12	$11.13	$1.71	$47.96	$6,330.72	$34.08	$10.79	$1.66	$46.53	$6,141.96	-2.98%
33000 LUMEN	Small Flood PS	15,996	137	2,191,452	$7.18	$3.54	$3.61	$14.33	$229,222.68	$6.97	$3.44	$3.50	$13.91	$222,504.36	-2.93%
33000 LUMEN	Shoebox PS	564	137	77,268	$8.59	$3.94	$3.61	$16.14	$9,102.96	$8.34	$3.82	$3.50	$15.66	$8,832.24	-2.97%
68000 LUMEN	Flood PS	804	288	231,552	$7.41	$5.95	$7.59	$20.95	$16,843.80	$7.19	$5.77	$7.37	$20.33	$16,345.32	-2.96%

TAX REFORM
GULF POWER COMPANY
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					Present Rates					Proposed Rates					
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Change
METAL HALIDE PULSE START (OS-I/II) - PAID UP FRONT															
13000 LUMEN	Acorn PS PUF	3,372	65	219,180	N/A	$5.84	$1.71	$7.55	$25,458.60	N/A	$5.67	$1.66	$7.33	$24,716.76	-2.91%
13000 LUMEN	Colonial PS PUF	396	65	25,740	N/A	$2.74	$1.71	$4.45	$1,762.20	N/A	$2.66	$1.66	$4.32	$1,710.72	-2.92%
13000 LUMEN	Destin Single PS PUF	84	65	5,460	N/A	$11.13	$1.71	$12.84	$1,078.56	N/A	$10.79	$1.66	$12.45	$1,045.80	-3.04%
33000 LUMEN	Small Flood PS PUF	780	137	106,860	N/A	$3.54	$3.61	$7.15	$5,577.00	N/A	$3.44	$3.50	$6.94	$5,413.20	-2.94%
33000 LUMEN	Shoebox PS PUF	324	137	44,388	N/A	$3.94	$3.61	$7.55	$2,446.20	N/A	$3.82	$3.50	$7.32	$2,371.68	-3.05%
LED (OS-I/II)															
3776 LUMEN	Acorn	24	26	624	$19.01	$9.82	$0.69	$29.52	$708.48	$18.45	$9.53	$0.67	$28.65	$687.60	-2.95%
4440 LUMEN	Street Light	432	25	10,800	$14.76	$5.05	$0.66	$20.47	$8,843.04	$14.32	$4.90	$0.64	$19.86	$8,579.52	-2.98%
5100 LUMEN	Cobrahead S2	3,024	25	75,600	$6.47	$4.22	$0.66	$11.35	$34,322.40	$6.28	$4.10	$0.64	$11.02	$33,324.48	-2.91%
10200 LUMEN	Cobrahead S3	792	46	36,432	$7.97	$4.87	$1.21	$14.05	$11,127.60	$7.73	$4.73	$1.18	$13.64	$10,802.88	-2.92%
6320 LUMEN	ATB071 S2/S3	420	24	10,080	$8.07	$5.48	$0.63	$14.18	$5,955.60	$7.83	$5.33	$0.61	$13.77	$5,783.40	-2.89%
9200 LUMEN	ATB1 105 S3	312	36	11,232	$11.79	$6.62	$0.95	$19.36	$6,040.32	$11.44	$6.42	$0.92	$18.78	$5,859.36	-3.00%
23240 LUMEN	ATB2 280 S4	26,436	96	2,537,856	$13.34	$7.69	$2.53	$23.56	$622,832.16	$12.95	$7.46	$2.46	$22.87	$604,591.32	-2.93%
9600 LUMEN	E157 SAW	24	54	1,296	$19.97	$5.96	$1.42	$27.35	$656.40	$19.38	$5.78	$1.38	$26.54	$636.96	-2.96%
7377 LUMEN	WP9 A2/S2	36	48	1,728	$44.88	$14.87	$1.27	$61.02	$2,196.72	$43.55	$14.43	$1.23	$59.21	$2,131.56	-2.97%
15228 LUMEN	Destin Double	12	72	864	$68.67	$32.85	$1.90	$103.42	$1,241.04	$66.64	$31.88	$1.84	$100.36	$1,204.32	-2.96%
9336 LUMEN	ATB0 108	14,784	37	547,008	$7.47	$4.85	$0.98	$13.30	$196,627.20	$7.25	$4.71	$0.95	$12.91	$190,861.44	-2.93%
3640 LUMEN	Colonial	15,900	15	238,500	$8.02	$5.15	$0.40	$13.57	$215,763.00	$7.78	$5.00	$0.38	$13.16	$209,244.00	-3.02%
4204 LUMEN	LED Security Lt	94,596	15	1,418,940	$4.89	$2.93	$0.40	$8.22	$777,579.12	$4.75	$2.84	$0.38	$7.97	$753,930.12	-3.04%
5510 LUMEN	LED Roadway 1	9,420	21	197,820	$5.88	$3.73	$0.55	$10.16	$95,707.20	$5.71	$3.63	$0.54	$9.88	$93,069.60	-2.76%
32327 LUMEN	Galleon 6sq	4,560	108	492,480	$21.22	$11.22	$2.85	$35.29	$160,922.40	$20.59	$10.89	$2.76	$34.24	$156,134.40	-2.98%
36000 LUMEN	Flood 421 W	27,060	145	3,923,700	$18.37	$10.15	$3.82	$32.34	$875,120.40	$17.83	$9.85	$3.71	$31.39	$849,413.40	-2.94%
5355 LUMEN	Wildlife Cert	552	36	19,872	$18.03	$9.57	$0.95	$28.55	$15,759.60	$17.50	$9.29	$0.92	$27.71	$15,295.92	-2.94%
LED (OS-I/II) - PAID UP FRONT															
3640 LUMEN	Colonial PUF	1,080	15	16,200	N/A	$5.15	$0.40	$5.55	$5,994.00	N/A	$5.00	$0.38	$5.38	$5,810.40	-3.06%
3776 LUMEN	Acorn PUF	864	26	22,464	N/A	$9.82	$0.69	$10.51	$9,080.64	N/A	$9.53	$0.67	$10.20	$8,812.80	-2.95%
4204 LUMEN	LED Security Lt PUF	72	15	1,080	N/A	$2.93	$0.40	$3.33	$239.76	N/A	$2.84	$0.38	$3.22	$231.84	-3.30%
5000 LUMEN	Acorn A5 PUF	348	19	6,612	N/A	$8.46	$0.50	$8.96	$3,118.08	N/A	$8.21	$0.49	$8.70	$3,027.60	-2.90%
5032 LUMEN	LG Colonial PUF	72	25	1,800	N/A	$6.06	$0.66	$6.72	$483.84	N/A	$5.88	$0.64	$6.52	$469.44	-2.98%
5100 LUMEN	Cobrahead S2 PUF	36	25	900	N/A	$4.22	$0.66	$4.88	$175.68	N/A	$4.10	$0.64	$4.74	$170.64	-2.87%
5355 LUMEN	Wildlife Cert PUF	2,616	36	94,176	N/A	$9.57	$0.95	$10.52	$27,520.32	N/A	$9.29	$0.92	$10.21	$26,709.36	-2.95%
5510 LUMEN	LED Roadway 1 PUF	59,592	21	1,251,432	N/A	$3.73	$0.55	$4.28	$255,053.76	N/A	$3.63	$0.54	$4.17	$248,498.64	-2.57%
6320 LUMEN	ATB071 S2/S3 PUF	2,052	24	49,248	N/A	$5.48	$0.63	$6.11	$12,537.72	N/A	$5.33	$0.61	$5.94	$12,188.88	-2.78%
7200 LUMEN	E132 A3 PUF	828	45	37,260	N/A	$8.63	$1.19	$9.82	$8,130.96	N/A	$8.37	$1.15	$9.52	$7,882.56	-3.05%
7377 LUMEN	WP9 A2/S2 PUF	960	48	46,080	N/A	$14.87	$1.27	$16.14	$15,494.40	N/A	$14.43	$1.23	$15.66	$15,033.60	-2.97%
9200 LUMEN	ATB1 105 S3 PUF	1,152	36	41,472	N/A	$6.62	$0.95	$7.57	$8,720.64	N/A	$6.42	$0.92	$7.34	$8,455.68	-3.04%

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					Present Rates					Proposed Rates					
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Change
LED (OS-I/II) - PAID UP FRONT (Cont.)															
9336 LUMEN	ATB0 108 PUF	1,332	37	49,284	N/A	$4.85	$0.98	$5.83	$7,765.56	N/A	$4.71	$0.95	$5.66	$7,539.12	-2.92%
9600 LUMEN	E157 SAW PUF	288	54	15,552	N/A	$5.96	$1.42	$7.38	$2,125.44	N/A	$5.78	$1.38	$7.16	$2,062.08	-2.98%
10200 LUMEN	Cobrahead S3 PUF	2,520	46	115,920	N/A	$4.87	$1.21	$6.08	$15,321.60	N/A	$4.73	$1.18	$5.91	$14,893.20	-2.80%
23240 LUMEN	ATB2 280 S4 PUF	18,372	96	1,763,712	N/A	$7.69	$2.53	$10.22	$187,761.84	N/A	$7.46	$2.46	$9.92	$182,250.24	-2.94%
36000 LUMEN	Flood 421 W PUF	1,224	145	177,480	N/A	$10.15	$3.82	$13.97	$17,099.28	N/A	$9.85	$3.71	$13.56	$16,597.44	-2.93%
MERCURY VAPOR (OS-I/II)															
7000 LUMEN	Open Bottom	12	67	804	$2.30	$1.42	$1.77	$5.49	$65.88	$2.23	$1.38	$1.71	$5.32	$63.84	-3.10%
3200 LUMEN	Cobrahead	12	39	468	$4.26	$1.99	$1.03	$7.28	$87.36	$4.13	$1.93	$1.00	$7.06	$84.72	-3.02%
7000 LUMEN	Cobrahead	12	67	804	$3.86	$1.86	$1.77	$7.49	$89.88	$3.75	$1.81	$1.71	$7.27	$87.24	-2.94%
9400 LUMEN	Cobrahead	12	95	1,140	$5.08	$2.26	$2.50	$9.84	$118.08	$4.93	$2.19	$2.43	$9.55	$114.60	-2.95%
17000 LUMEN	Cobrahead	12	152	1,824	$5.55	$2.36	$4.01	$11.92	$143.04	$5.39	$2.29	$3.89	$11.57	$138.84	-2.94%
48000 LUMEN	Cobrahead	12	372	4,464	$11.13	$4.09	$9.81	$25.03	$300.36	$10.80	$3.97	$9.52	$24.29	$291.48	-2.96%
17000 LUMEN	Directional	12	163	1,956	$8.35	$3.16	$4.30	$15.81	$189.72	$8.10	$3.07	$4.17	$15.34	$184.08	-2.97%
CUSTOMER OWNED MISC STREET/OUTDOOR LIGHTING (OS-I/II)				3,969,260	N/A	N/A	$0.02636	N/A	$104,629.69	N/A	N/A	$0.02558	N/A	$101,533.67	-2.96%
CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - HIGH PRESSURE SODIUM VAPOR (OS-I/II)															
8800 LUMEN	Unmetered	1,116	41	45,756	N/A	$0.73	$1.08	$1.81	$2,019.96	N/A	$0.71	$1.05	$1.76	$1,964.16	-2.76%
46000 LUMEN	Unmetered	288	164	47,232	N/A	$0.74	$4.32	$5.06	$1,457.28	N/A	$0.72	$4.20	$4.92	$1,416.96	-2.77%
8800 LUMEN	Metered	192	N/A	N/A	N/A	$0.73	N/A	$0.73	$140.16	N/A	$0.71	N/A	$0.71	$136.32	-2.74%
20000 LUMEN	Metered	408	N/A	N/A	N/A	$0.74	N/A	$0.74	$301.92	N/A	$0.72	N/A	$0.72	$293.76	-2.70%
25000 LUMEN	Metered	588	N/A	N/A	N/A	$0.75	N/A	$0.75	$441.00	N/A	$0.73	N/A	$0.73	$429.24	-2.67%
46000 LUMEN	Metered	252	N/A	N/A	N/A	$0.74	N/A	$0.74	$186.48	N/A	$0.72	N/A	$0.72	$181.44	-2.70%
CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - METAL HALIDE (OS-I/II)															
32000 LUMEN	Unmetered	120	163	19,560	N/A	$0.88	$4.30	$5.18	$621.60	N/A	$0.85	$4.17	$5.02	$602.40	-3.09%
32000 LUMEN	Metered	360	N/A	N/A	N/A	$0.88	N/A	$0.88	$316.80	N/A	$0.85	N/A	$0.85	$306.00	-3.41%
100000 LUMEN	Large Flood	96	378	36,288	N/A	$3.26	$9.96	$13.22	$1,269.12	N/A	$3.16	$9.67	$12.83	$1,231.68	-2.95%
HIGH PRESSURE SODIUM VAPOR - CUSTOMER OWNED/CUSTOMER MAINTAINED (OS-I/II)															
Customer-Owned	8800	372	41	15,252	N/A	N/A	$1.08	$1.08	$401.76	N/A	N/A	$1.05	$1.05	$390.60	-2.78%
Customer-Owned	20000	48	80	3,840	N/A	N/A	$2.11	$2.11	$101.28	N/A	N/A	$2.05	$2.05	$98.40	-2.84%
Customer-Owned	25000	4,224	100	422,400	N/A	N/A	$2.64	$2.64	$11,151.36	N/A	N/A	$2.56	$2.56	$10,813.44	-3.03%

TAX REFORM
GULF POWER COMPANY
RATE SCHEDULE OS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
					Present Rates					Proposed Rates					
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge	$ Total Revenue	Percent Change
ADDITIONAL FACILITIES															
13 Ft. Decorative Concrete Pole		41,976	N/A	N/A	N/A	N/A	N/A	$18.88	$792,506.88	N/A	N/A	N/A	$18.15	$761,864.40	-3.87%
16 Ft. Decorative Base Aluminum Pole		828	N/A	N/A	N/A	N/A	N/A	$13.56	$11,227.68	N/A	N/A	N/A	$13.04	$10,797.12	-3.83%
17 Ft. Decorative Base Aluminum Pole		2,400	N/A	N/A	N/A	N/A	N/A	$19.81	$47,544.00	N/A	N/A	N/A	$19.05	$45,720.00	-3.84%
20 Ft. Fiberglass Pole		28,908	N/A	N/A	N/A	N/A	N/A	$7.01	$202,645.08	N/A	N/A	N/A	$6.74	$194,839.92	-3.85%
20 Ft. Aluminum Round Tapered Pole		2,964	N/A	N/A	N/A	N/A	N/A	$6.17	$18,287.88	N/A	N/A	N/A	$5.93	$17,576.52	-3.89%
25 Ft. Aluminum Round Tapered Pole		72	N/A	N/A	N/A	N/A	N/A	$21.95	$1,580.40	N/A	N/A	N/A	$21.11	$1,519.92	-3.83%
30 Ft. Wood Pole		27,420	N/A	N/A	N/A	N/A	N/A	$4.55	$124,761.00	N/A	N/A	N/A	$4.38	$120,099.60	-3.74%
30 Ft. Aluminum Pole		696	N/A	N/A	N/A	N/A	N/A	$24.34	$16,940.64	N/A	N/A	N/A	$23.40	$16,286.40	-3.86%
30 Ft. Concrete Pole		78,180	N/A	N/A	N/A	N/A	N/A	$9.51	$743,491.80	N/A	N/A	N/A	$9.14	$714,565.20	-3.89%
30 Ft. Fiberglass Pole w/Pedestal		720	N/A	N/A	N/A	N/A	N/A	$45.01	$32,407.20	N/A	N/A	N/A	$43.28	$31,161.60	-3.84%
35 Ft. Concrete Pole		1,896	N/A	N/A	N/A	N/A	N/A	$13.85	$26,259.60	N/A	N/A	N/A	$13.32	$25,254.72	-3.83%
35 Ft. Tenon Top Concrete Pole		2,052	N/A	N/A	N/A	N/A	N/A	$19.13	$39,254.76	N/A	N/A	N/A	$18.39	$37,736.28	-3.87%
35 Ft. Wood Pole		78,996	N/A	N/A	N/A	N/A	N/A	$6.61	$522,163.56	N/A	N/A	N/A	$6.36	$502,414.56	-3.78%
35 Ft. Aluminum Pole		216	N/A	N/A	N/A	N/A	N/A	$27.28	$5,892.48	N/A	N/A	N/A	$26.23	$5,665.68	-3.85%
40 Ft. Wood Pole		2,604	N/A	N/A	N/A	N/A	N/A	$8.12	$21,144.48	N/A	N/A	N/A	$7.81	$20,337.24	-3.82%
45 Ft. Concrete Pole (Tenon Top)		2,100	N/A	N/A	N/A	N/A	N/A	$25.11	$52,731.00	N/A	N/A	N/A	$24.14	$50,694.00	-3.86%
Single Arm - Shoebox		708	N/A	N/A	N/A	N/A	N/A	$2.63	$1,862.04	N/A	N/A	N/A	$2.53	$1,791.24	-3.80%
Double Arm - Shoebox		456	N/A	N/A	N/A	N/A	N/A	$2.92	$1,331.52	N/A	N/A	N/A	$2.81	$1,281.36	-3.77%
Tenon Top Adapter		696	N/A	N/A	N/A	N/A	N/A	$4.86	$3,382.56	N/A	N/A	N/A	$4.67	$3,250.32	-3.91%
Optional 100 Amp Relay		36	N/A	N/A	N/A	N/A	N/A	$27.20	$979.20	N/A	N/A	N/A	$26.15	$941.40	-3.86%
Miscellaneous Additional Facilities		$808,758.27	N/A	N/A	N/A	N/A	N/A	N/A	$808,758.27	N/A	N/A	N/A	N/A	$808,758.27	0.00%
SUBTOTAL OS-I/II PAGE 1 OF 5				68,389,512					$8,880,898.80					$8,618,505.36	
SUBTOTAL OS-I/II PAGE 2 OF 5				17,529,840					$1,397,543.52					$1,356,458.64	
SUBTOTAL OS-I/II PAGE 3 OF 5				11,495,184					$3,414,275.04					$3,314,099.88	
SUBTOTAL OS-I/II PAGE 4 OF 5				6,692,996					$354,106.45					$343,704.95	
SUBTOTAL OS-I/II PAGE 5 OF 5				-					$3,475,152.03					$3,372,555.75	
TOTAL OS-I/II KWH AND REVENUE				104,107,532					$17,521,975.84					$17,005,324.58	
TOTAL OS-III KWH AND REVENUE				47,117,434	N/A	N/A	$0.04968		$2,340,794.12	N/A	N/A	$0.04821		$2,271,531.49	-2.96%
TOTAL OS KWH AND REVENUE				151,224,966					$19,862,769.96					$19,276,856.07	
													TOTAL CHANGE	-$585,913.89	
													% CHANGE	-2.95%	

Section E
Proof of Revenue
Summary

TAX REFORM
RATE DESIGN PROOF OF REVENUE SUMMARY

(1) RATE CLASS	(2) TARGET CHANGE FROM SALE OF ELECTRICITY FROM SECTION B	(3) ACHIEVED CHANGE PER PROOF OF REVENUE FROM SECTIONS C & D
RESIDENTIAL	($10,912,895)	($10,928,994)
GS	($747,881)	($748,635)
GSD/GSDT	($3,622,892)	($3,622,763)
LP/LPT	($943,175)	($941,239)
MAJOR ACCTS	($1,369,000)	($1,368,851)
OS	($585,913)	($585,914)
TOTAL RETAIL:	($18,181,756)	($18,196,396)

Gulf Power Company
Fuel Clause Tax Savings Summary
For Rates Effective April 2018
February 12, 2018

		2018	
1	Jurisdictional ADIT credit (unprotected) adjusted for revenue tax	$ (69,456,000)	
2	Prorated base rate adjustment (Line 15 x 2.5 ÷ 12)	(3,791,667)	
3	One-time 2018 Tax Savings Credit	$ (73,247,667)	
4	Retail kWh Sales (April - December)	8,561,315,000	
5	Current Approved Levelized Retail Fuel Rate	3.789	¢/kWh
6	Retail Tax Savings Credit (Line 3 ÷ Line 4 x 100)	(0.856)	¢/kWh
7	Proposed Retail Fuel Rate (Line 5 - Line 6)	2.933	¢/kWh

Cost Recovery Factors (¢ per kWh)

	Rate Schedules	Standard
8	Group A (RS, RSVP, RSTOU, GS, GSD, GSTOU, OS-III)	2.949
9	Group B (LP)	2.909
10	Group C (PX, RTP)	2.865
11	Group D (OS-I/II)	2.915

	Rate Schedules (Time-of-use)	On-peak	Off-peak
12	Group A (GSDT, SBS)	3.530	2.709
13	Group B (LPT, SBS)	3.482	2.672
14	Group C (PXT, SBS)	3.429	2.631

15 Prospective annual adjustment to base rates $ (18,200,000) per year

SCHEDULE E-1D
Revised 2/12/2018

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: APRIL 2018 - DECEMBER 2018

	NET ENERGY FOR LOAD %
On-Peak	29.29
Off-Peak	70.71
	100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per kWh Sold	3.5015	4.0780	3.2624
Jurisdictional Loss Factor	1.0012	1.0012	1.0012
Jurisdictional Fuel Factor	3.5057	4.0829	3.2663
GPIF	(0.0187)	(0.0187)	(0.0187)
True-Up	0.2994	0.2994	0.2994
TOTAL	3.7864	4.3636	3.547
Revenue Tax Factor	1.00072	1.00072	1.00072
Approved Recovery Factor	3.7891	4.3667	3.5496
Tax Reform Savings Factor	**(0.856)**	**(0.856)**	**(0.856)**
Recovery Factor Rounded to the Nearest .001 ¢/kWh	2.933	3.511	2.694

HOURS:		
	ON-PEAK	25.00%
	OFF-PEAK	75.00%
		100.00%

SCHEDULE E-1E
Revised 2/12/2018

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: APRIL 2018 - DECEMBER 2018

Group	Rate Schedules	Revised Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, RSVP, RSTOU, GS, GSD, GSDT, GSTOU, OSIII, SBS (1)	2.933	1.00555	2.949
B	LP, LPT, SBS (2)	2.933	0.99188	2.909
C	PX,PXT, RTP, SBS (3)	2.933	0.97668	2.865
D	OS-I/II	2.933	1.00560	2.915 *

Group		TOU
A	On-Peak	3.530
	Off-Peak	2.709
B	On-Peak	3.482
	Off-Peak	2.672
C	On-Peak	3.429
	Off-Peak	2.631
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	3.511	¢ / kWh	x	0.2500	=	0.878	¢ / kWh
	Off-Peak	2.694	¢ / kWh	x	0.7500	=	2.021	¢ / kWh
							2.899	¢ / kWh
		Line Loss Multiplier				x	1.00560	
							2.915	¢ / kWh

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 kW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 kW
(3) Includes SBS customers with a Contract Demand over 7,499 kW

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Summary of Tax Savings
February 12, 2018

ECRC Revenue Requirement

1	Approved 2018 Retail Revenue Requirement included in current rates	$ 203,589,886
2	Revised 2018 Retail Revenue Requirement included in proposed rates	187,992,095
3	Tax Savings	$ 15,597,790

Cost of Capital

		38.575% Effective Tax Rate	25.345% Effective Tax Rate
4	Jurisdictional Revenue Requirement Rate of Return	8.4144%	7.1734%

ECRC Cost Recovery Factors (¢ per kWh)

	Rate Class	Current	Proposed
5	RS, RSVP, RSTOU	2.124	1.959
6	GS	1.956	1.805
7	GSD, GSDT, GSTOU	1.733	1.601
8	LP, LPT	1.547	1.431
9	PX, PXT, RTP, SBS	1.482	1.371
10	OS-I/II	0.570	0.537
11	OS-III	1.361	1.261

Schedule 8P
Revised 2/12/2018

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2018 - December 2018

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Amount ($000s)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) **Current** Revenue Requirement Rate %	(6) **Proposed** Revenue Requirement Rate %
1	Bonds	743,673	30.7440	4.40	1.3527	1.3527	1.3527
2	Short-Term Debt	28,504	1.1784	3.02	0.0356	0.0356	0.0356
3	Preferred Stock	94,609	3.9112	6.15	0.2405	0.3915	0.3221
4	Common Stock	957,875	39.5993	10.25	4.0589	6.6079	5.4369
5	Customer Deposits	24,536	1.0143	2.30	0.0233	0.0233	0.0233
6	Deferred Taxes	568,999	23.5229				
7	Investment Tax Credit	721	0.0298	7.61	0.0023	0.0034	0.0028
8	Total	2,418,917	100.0000		5.7133	8.4144	7.1734
	ITC Component:						
9	Debt	743,673	41.4036	4.40	1.8218	0.0005	0.0005
10	Equity-Preferred	94,609	5.2673	6.15	0.3239	0.0002	0.0001
11	-Common	957,875	53.3291	10.25	5.4662	0.0027	0.0022
12		1,796,157	100.0000		7.6119	0.0034	0.0028
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.4121	1.4121
14	Total Equity Component (Lines 3, 4, 10, and 11)					7.0023	5.7613
15	Total Revenue Requirement Rate of Return					8.4144	7.1734

Column:

(1) Based on MFR D-1a in Docket No. 160186-EI with the following adjustments in order to reflect specific terms in the Stipulation and Settlement Agreement under the same Docket.
-Reduced the common equity balance and increased the long-term debt balance in order to calculate a 52.5% equity ratio based on jurisdictional investors sources of capital (long-term debt, short-term debt, preference stock and common equity)

(2) Column (1) / Total Column (1)

(3) Based on MFR D-1a in Docket No. 160186-EI with the following adjustments in order to reflect specific terms in the Stipulation and Settlement Agreement under the same Docket.
-Reduced the common equity cost rate to 10.25%.

(4) Column (2) x Column (3)

(5, 6) For equity components: Column (4) / (1 - effective income tax rate);
Current: 38.575%; Proposed: 25.345% = effective income tax rate
For debt components: Column (4)

Schedule 7P
Revised 2/12/2018

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2018 - December 2018

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Rate Class	Percentage of kWh Sales at Generation (%)	Percentage of 12 CP Demand at Generation (%)	Energy-Related Costs	Demand-Related Costs	Total Environmental Costs	Projected Sales at Meter (kWh)	Environmental Cost Recovery Factors (¢/kWh)
RS, RSVP, RSTOU	49.83290%	57.74834%	16,723,159	89,182,856	105,906,015	5,405,053,000	1.959
GS	2.85069%	2.99526%	956,648	4,625,689	5,582,337	309,196,000	1.805
GSD, GSDT, GSTOU	22.70391%	20.60040%	7,619,084	31,813,945	39,433,029	2,462,912,000	1.601
LP, LPT	8.13603%	6.52155%	2,730,327	10,071,466	12,801,793	894,459,000	1.431
PX, PXT, RTP, SBS	15.08774%	11.68414%	5,063,214	18,044,241	23,107,455	1,684,946,000	1.371
OS-I/II	0.93999%	0.15045%	315,446	232,345	547,791	101,954,000	0.537
OS-III	0.44874%	0.29986%	150,590	463,085	613,675	48,672,000	1.261
TOTAL	100.00000%	100.00000%	$33,558,468	$154,433,627	187,992,095	10,907,192,000	1.724

Notes:
(A) From Schedule 6P, Col H
(B) From Schedule 6P, Col I
(C) Column A x Total Energy $ from Schedule 1P, line 5
(D) Column B x Total Demand $ from Schedule 1P, line 5
(E) Column C + Column D
(F) Projected kWh sales for the period January 2018 - December 2018
(G) Column E x 100 / Column F

GULF POWER COMPANY
Residential Bill Comparison
For Monthly Usage of 1,000 kWh
Proposed For The Period of: April 2018 - December 2018

	Current Approved Jan. 18 ($/1,000 kWh)	Proposed Apr. 18 - Dec. 18 ($/1,000 kWh)	Difference from Current ($)	Difference from Current (%)
Base Rate	$ 71.31	$ 69.17	$ (2.14)	-3.0%
Fuel Cost Recovery	38.10	29.49	(8.61)	-22.6%
Capacity Cost Recovery	8.35	8.35	-	0.0%
Energy Conservation Cost Recovery	1.40	1.40	-	0.0%
Environmental Cost Recovery	21.24	19.59	(1.65)	-7.8%
Subtotal	$ 140.40	$ 128.00	$ (12.40)	-8.8%
Gross Receipts Tax	$ 3.60	$ 3.28	$ (0.32)	-8.9%
Total	$ 144.00	$ 131.28	$ (12.72)	-8.8%

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Petition for Increase in Rates By Gulf Power Company	)	Docket No.: 20160186-EI
IN RE: Petition to establish a generic docket to Investigate and adjust rates for 2018 tax savings, By Office of Public Counsel	)	Docket No.: 20180013-PU

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing has been furnished by electronic mail this 14th day of February, 2018 to the following:

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FEDERAL RESERVE press release

For release at 2 p.m. EDT

March 21, 2018

Information received since the Federal Open Market Committee met in January indicates that the labor market has continued to strengthen and that economic activity has been rising at a moderate rate. Job gains have been strong in recent months, and the unemployment rate has stayed low. Recent data suggest that growth rates of household spending and business fixed investment have moderated from their strong fourth-quarter readings. On a 12-month basis, both overall inflation and inflation for items other than food and energy have continued to run below 2 percent. Market-based measures of inflation compensation have increased in recent months but remain low; survey-based measures of longer-term inflation expectations are little changed, on balance.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The economic outlook has strengthened in recent months. The Committee expects that, with further gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace in the medium term and labor market conditions will remain strong. Inflation on a 12-month basis is expected to move up in coming months and to stabilize around the Committee's 2 percent objective over the medium term. Near-term risks to the economic outlook appear roughly balanced, but the Committee is monitoring inflation developments closely.

In view of realized and expected labor market conditions and inflation, the Committee decided to raise the target range for the federal funds rate to 1-1/2 to 1-3/4 percent. The stance of monetary policy remains accommodative, thereby supporting strong labor market conditions and a sustained return to 2 percent inflation.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This

(more)

March 21, 2018

For release at 2 p.m. EDT

assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. The Committee will carefully monitor actual and expected inflation developments relative to its symmetric inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant further gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.

Voting for the FOMC monetary policy action were Jerome H. Powell, Chairman; William C. Dudley, Vice Chairman; Thomas I. Barkin; Raphael W. Bostic; Lael Brainard; Loretta J. Mester; Randal K. Quarles; and John C. Williams.

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For release at 2 p.m. EDT March 21, 2018

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 21, 2018:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on required and excess reserve balances to 1.75 percent, effective March 22, 2018.

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

> "Effective March 22, 2018, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 1-1/2 to 1-3/4 percent, including overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 1.50 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.
>
> The Committee directs the Desk to continue rolling over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing during March that exceeds $12 billion, and to continue reinvesting in agency mortgage-backed securities the amount of principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during March that exceeds $8 billion. Effective in April, the Committee directs the Desk to roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing during each calendar month that exceeds $18 billion, and to reinvest in agency mortgage-backed securities the amount of principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month that exceeds $12 billion. Small deviations from these amounts for operational reasons are acceptable.
>
> The Committee also directs the Desk to engage in dollar roll and coupon swap

(more)

For release at 2 p.m. EDT March 21, 2018

transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 2.25 percent, effective March 22, 2018. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, New York, Philadelphia, Cleveland, Richmond, Atlanta, St. Louis, Kansas City, Dallas, and San Francisco.

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

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

Current **FAQs**
Informing the public about the Federal Reserve

What does the Federal Reserve mean when it says monetary policy remains "accommodative"?

In general, monetary policy is considered to be "accommodative" when it aims to make interest rates sufficiently low to spur strong enough economic growth to reduce unemployment or to prevent unemployment from rising. For example, toward the end of 2008, in the midst of the global financial crisis and Great Recession, with unemployment above 6-1/2 percent and rising, and inflation below 2 percent and expected to decline, the Federal Open Market Committee (FOMC) pushed short-term interest rates to nearly zero. The FOMC then embarked on a series of large-scale asset purchase programs to reduce longer-term interest rates.

By December 2015, the unemployment rate had come down to 5 percent and there had been considerable improvement in a broad range of indicators of labor market conditions. The Committee projected further improvement, and it was reasonably confident that inflation would rise to 2 percent over the medium term after prices of energy and imported goods stop declining. Considering the economic outlook and the fact that policy actions take time to affect the economy, the FOMC decided to increase its target range for the federal funds rate by 1/4 percentage point. The stance of monetary policy remains accommodative after this increase in the sense that interest rates remain low enough to support further strengthening in labor market conditions and a return to 2 percent inflation.

To learn more about how the Committee's assessment of the economic situation, its outlook for the economy, and its current stance of monetary policy, read the Committee's postmeeting statement or meeting minutes here: http://www.federalreserve.gov/monetarypolicy/fomccalendars.htm.

UBS

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1 February 2018

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Initiation of Coverage

North American Regulated Utilities

Wait For It. Initiating Coverage on 30 Regulated Utilities

Equities

Americas
Utilities

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Add to Regulated Utility (RU) Holdings Opportunistically in 1H18

After a 16% correction vs the S&P500 over the last three months, RU's are cheap, but we recommend adding to positions opportunistically in 1H18 for two reasons. First, RUs could lag during the 1Q earnings revision cycle as tax reform is incorporated into S&P earnings. Second, there is significant debate about interest rate moves in 2018 (Lesson Learned: Revising forecasts & taking stock). Based on our 35 year rate cycle analysis and our proprietary equity duration analysis, we believe this concern is overdone.

RUs Newly Cheap vs. Bond Yields and Market P/Es

RUs crossed into undervalued territory comparing Baa bond to utility dividend yields in December. RUs offer 12% upside to the mean of this relationship. The group now discounts a 3.14% US 10-year T-note. The downside risk to the call is a drop to a 2 SD gap or 5% more. There have only been 5 such examples since 1981. RUs also crossed the undervalued line vs the S&P 500 on a relative P/E basis and are now 12% cheap. Finally, income fund outflows have slowed; hinting sellers may be near exhaustion.

Fundamentals Strong Combining CapEx Visibility with Constructive Regulation

Our 5 year capital expenditure survey shows annual rate base growth of 5.3%. We believe there is room for upward revision. We see infrastructure needs ranging from replacement of aging plant to modernizing the grid to enable environmental and Cyber and Physical security improvements driving upside. US regulation has set allowed return spreads on equity investment vs. the 10 year T-note at 730bp. This is consistent with the last 5 years and the highest in modern history. It covers RUs' cost of capital amply and incentivizes further investment. These returns appear sustainable based on our unique regulatory trend analysis and product affordability work.

Recommended Stocks

We use a proprietary valuation framework supported by robust analysis of rate base growth, regulation and business-specific risks. The framework leverages performance factor analysis from UBS's quantitative analytics team. Our recommendations fall into three categories. 1) High quality total return compounders; 2) Higher growth Multi-Utilities; and 3) Values with a catalyst in 2018. Focus stocks are DUK, SRE and EXC.

Figure 1: Regulated Utilities Recommended Stocks Summary

Rating	Ticker	Current Price	UBS Price Target	Total Return inc. Div. Yld	UBS 2018 EPS	UBS 2019 EPS	UBS 2020 EPS	2019 P/E Ratio	2019 Prem/ Disc	Current Dividend Yield	5 Yr EPS Growth	5 Yr DPS Growth
Higher Quality Total Return Compounders												
Buy	DUK	$78.50	$91	20%	$4.74	$5.03	$5.18	15.6x	(3%)	4.54%	4.1%	4.0%
Buy	AEP	$68.78	$76	14%	$3.85	$4.18	$4.46	16.5x	3%	3.61%	6.3%	4.8%
Higher Growth Mutli-Utilities												
Buy	SRE	$107.02	$124	19%	$5.50	$6.21	$7.73	17.2x	8%	2.82%	10.2%	9.0%
Buy	D	$76.44	$85	15%	$4.19	$4.28	$4.45	17.9x	12%	4.37%	6.6%	10.0%
Buy	NEE	$158.42	$177	14%	$7.88	$8.41	$9.06	18.8x	18%	2.20%	9.3%	12.0%
Values with a Catalyst in 2018												
Buy	PPL	$31.87	$40	31%	$2.35	$2.47	$2.66	12.9x	(20%)	4.77%	5.6%	4.0%
Buy	FE	$32.90	$39	23%	$2.45	$2.40	$2.28	13.7x	(14%)	4.38%	(5.7%)	0.0%
Buy	EXC	$38.51	$44	17%	$2.91	$3.05	$2.85	12.6x	(21%)	3.17%	4.9%	5.3%

Source: Factset, UBS Equity Research

www.ubs.com/investmentresearch

North American Regulated Utilities

UBS Research THESIS MAP

MOST FAVORED

Duke Energy, Sempra Energy, and Exelon Corp

LEAST FAVORED

Hawaiian Electric Industries, PNM Resources, Portland General, and SCANA Corp.

PIVOTAL QUESTIONS

Q: Is Recent Underperformance the beginning of a Bear Market and can Regulated Utilities Outperform in a Fed Hike Cycle?

The 16% correction vs the market in the last 3 months presents a buyable correction, in our view. RUs screen inexpensive vs. Baa Corporate Bond yields for the first time since 2013 and vs. S&P 500 earnings as well. We don't expect a broader bear market for RUs as fundamentals remain positive, driven by cap-ex visibility, low customer rate inflation, and a constructive regulatory and policy backdrop. Our analysis of rate cycles over the last 35 years shows that regulated utilities underperform on the way into a Fed hike series, are relative market performers during the program (Now), and are outperformers on the way out (see Figure 5). Further, the long equity duration (~20 years) of the group currently means regulated utilities are sensitive to Treasury note and bond yields more than the Fed Funds Rate. UBS' outlook calls for a flattening of the yield curve in 2018 but with an upward shift across the curve. UBS' expectation for the year-end 10-year Treasury note is 2.9% or 20bps higher than today.

Q: Can Utilities meet Consensus Growth Expectations?

Yes. As a cost plus regulated industry, growth is driven by capital spending. Over the next 5 years, our proprietary capex survey sets the average growth expectation for RUs at 5.3%. This is close to the middle of EPS guidance and 5 year consensus estimates for RU EPS (4.2%) and DPS (5.3%) growth. Based on our 25 years of experience covering the group, visibility for out-year spending improves with time; therefore backwardation in the capex survey suggests there may be room for upward revision.

Q: Will Regulation Remain Constructive and Support Capital Investment?

We believe that the regulatory backdrop will remain constructive in support of a robust investment environment. Allowed return spreads vs the US 10-year T-note were 730bp in the trailing 12 months. This is consistent with the last 5 years and the highest in the modern era (see Figure19). The return spread amply covers RU cost of capital, incenting spending. Even with robust spending, we forecast low customer rate inflation and affordable bills. Bill credits from tax reform will enhance affordability.

WHAT'S PRICED IN?

RUs Undervalued to Bonds and the Stock Market. RU dividend yields track the Moody's Baa corporate bond yield with a 91% correlation. Currently on this metric regulated utilities screen 12% cheap to fair value. In other terms, the group is discounting a 10-year T-Note at 3.12%. On a relative P/E basis to the S&P 500 consensus earnings forecast, regulated utilities screen undervalued by 12%. To justify the discount, the group would need to go ex-growth through 2019.

UBS VIEW

Add to RU holdings as the Buyable Correction Plays out in 1H '18: We believe that regulated utilities can still lag the market in the short run for two reasons. First, RUs are likely to suffer during the earnings revision cycle for the market when tax reform is incorporated into estimates. By contrast, tax is largely passed back to customers for RU's. Second, there is significant controversy about interest rate moves in 2018. The associated uncertainty may hold back performance in the near-term. The expected reward for patience is an annual total return forecast for the RU group of 15%.

EVIDENCE

RUs Already Screen Undervalued With Modest Downside Risk and Fundamentals are Strong: RU dividend yields have a 91% correlation to Moody's Baa corporate bond yields and are trading one standard deviation undervalued for the first time since spring of 2013 with 12% upside. The downside risk if RUs undershoot around the market move on tax reform is to two standard deviations undervalued or 5% from here. This has occurred only five times since 1981. RUs are also 12% undervalued on a relative P/E basis to the S&P500. Our 5 year capital expenditure survey shows annual rate base growth of 5.3%. We believe there is room for upward revision.

US regulation has set allowed return spreads on equity investment at 730bp. It covers RUs cost of capital amply and incentivizes further investment. These returns appear sustainable based on product affordability work. Electric affordability is the best since 1972. Electricity is 1.03% of consumer spending, which ranks it 13th in the list of household burdens.

Figure 2: Electric Utilities Universe

Rating	Ticker	Company	Current Price	UBS Price Target	Total Return inc. Div. Yld	UBS 2018 EPS	UBS 2019 EPS	UBS 2020 EPS	2019 P/E Ratio	2019 Prem/ Disc	Current Dividend Yield	5 Yr EPS Growth	5 Yr DPS Growth
Buy	PPL	PPL Corporation	$31.87	$40	31%	$2.35	$2.47	$2.66	12.9x	(20%)	4.8%	5.6%	4.0%
Buy	FE	FirstEnergy Corp	$32.90	$39	23%	$2.45	$2.40	$2.28	13.7x	(14%)	4.4%	-5.7%	0.0%
Buy	DUK	Duke Energy	$78.50	$91	20%	$4.74	$5.03	$5.18	15.6x	(3%)	4.5%	4.1%	4.0%
Buy	SRE	Sempra Energy	$107.02	$124	19%	$5.50	$6.21	$7.73	17.2x	8%	2.8%	10.2%	9.0%
Buy	EXC	Exelon	$38.51	$44	17%	$2.91	$3.05	$2.85	12.6x	(21%)	3.2%	4.9%	5.3%
Buy	D	Dominion Energy	$76.44	$85	15%	$4.19	$4.28	$4.45	17.9x	12%	4.4%	6.6%	10.0%
Buy	AEP	American Electric Power	$68.78	$76	14%	$3.85	$4.18	$4.46	16.5x	3%	3.6%	6.3%	4.8%
Buy	NEE	NextEra Energy	$158.42	$177	14%	$7.88	$8.41	$9.06	18.8x	18%	2.2%	9.3%	12.0%
Neutral	PCG	PG&E Corp	$42.43	$48	14%	$3.83	$4.02	$4.24	10.6x	(34%)	0.0%	5.0%	0.0%
Neutral	CMS	CMS Energy	$44.75	$49	11%	$2.33	$2.53	$2.74	17.7x	11%	2.8%	7.4%	6.0%
Neutral	EIX	Edison International	$62.53	$67	11%	$4.26	$4.57	$4.92	13.7x	(15%)	3.9%	5.1%	8.0%
Neutral	AES	AES Corp	$11.56	$12	10%	$1.15	$1.17	$1.20	9.8x	(39%)	4.5%	5.9%	8.3%
Neutral	WR	Westar Energy	$51.66	$55	9%	$2.58	$3.15	$3.29	16.4x	2%	2.9%	7.3%	3.1%
Neutral	ETR	Entergy Corp	$78.69	$82	9%	$4.51	$4.99	$5.37	15.8x	(2%)	4.3%	8.0%	2.0%
Neutral	ES	Eversource Energy	$63.09	$66	8%	$3.30	$3.53	$3.68	17.9x	12%	2.8%	5.8%	6.0%
Neutral	SO	Southern Company	$45.11	$46	8%	$3.06	$3.21	$3.37	14.1x	(12%)	5.1%	1.4%	3.4%
Neutral	OGE	OGE Energy Corp	$32.20	$33	7%	$2.14	$2.15	$2.13	15.0x	(6%)	3.4%	3.2%	10.0%
Neutral	XEL	Xcel Energy	$45.64	$47	6%	$2.41	$2.57	$2.74	17.8x	11%	3.2%	5.9%	6.0%
Neutral	GXP	Great Plains Energy	$31.12	$32	5%	$1.76	$1.89	$2.01	16.5x	3%	3.5%	3.6%	4.9%
Neutral	DTE	DTE Energy	$105.64	$108	5%	$5.63	$6.18	$6.50	17.1x	7%	3.1%	5.8%	6.0%
Neutral	WEC	WEC Energy Group	$64.30	$65	5%	$3.30	$3.49	$3.68	18.4x	15%	3.2%	5.8%	6.3%
Neutral	AEE	Ameren Corp	$56.63	$57	5%	$3.06	$3.17	$3.64	17.8x	11%	3.1%	7.1%	6.0%
Neutral	LNT	Alliant Energy	$39.75	$40	4%	$2.09	$2.21	$2.43	18.0x	12%	3.0%	6.4%	5.0%
Neutral	PNW	Pinacle West Capital Corp	$79.95	$81	4%	$4.33	$4.72	$5.02	16.9x	6%	3.1%	5.4%	5.0%
Neutral	ED	Consolidated Edison	$80.36	$80	3%	$4.30	$4.53	$4.76	17.7x	11%	3.3%	4.9%	3.0%
Neutral	PEG	Public Service Ent Group	$51.87	$52	3%	$3.19	$3.31	$3.17	15.7x	(2%)	2.9%	5.0%	4.0%
Sell	SCG	SCANA Corp	$40.64	$38	(2%)	$3.42	$3.36	$3.55	12.1x	(25%)	6.0%	-1.0%	6.5%
Sell	POR	Portland General	$42.35	$40	(2%)	$2.38	$2.44	$2.55	17.4x	8%	3.0%	3.9%	6.5%
Sell	PNM	PNM Resources	$38.10	$36	(2%)	$1.74	$2.09	$2.16	18.2x	14%	2.8%	3.9%	9.0%
Sell	HE	Hawaiian Electric Industries	$34.11	$29	(10%)	$1.91	$1.92	$2.02	17.8x	11%	3.6%	6.3%	0.0%
AVERAGE									16.0x				

Source: Factset, UBS Equity Research

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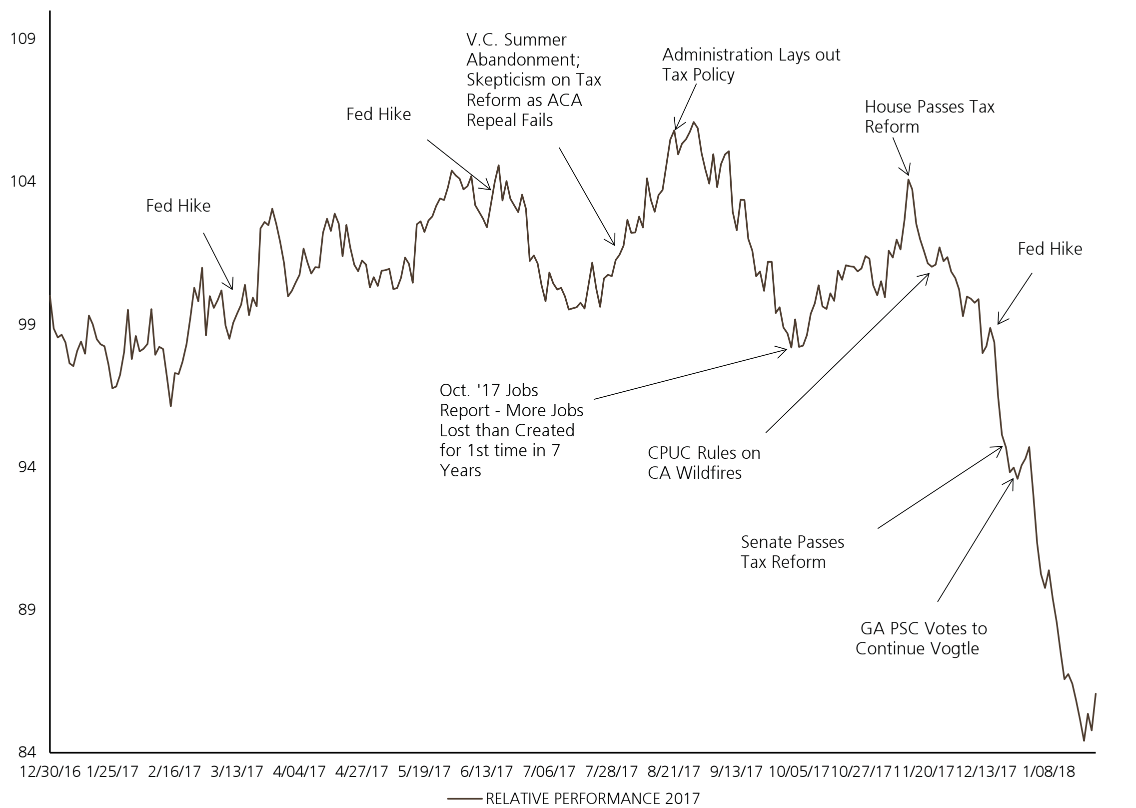
Underperformance by RUs: Beginning of a bear market or a buyable correction?

Regulated electric utilities (RUs) have sharply underperformed the broader market over the last few months (see Figure 1). This period of underperformance coincides with 1) the debate leading to passage of corporate tax reform which is better for the market than for regulated companies; 2) the 25 bp fed funds rate increase by the US Federal Reserve on 12/13/17; and 3) the emergence of two isolated but impactful regulatory challenges to fire disaster liability recovery in California and New Nuclear build cost over-run recovery in South Carolina and Georgia.

Figure 3: 2017 Relative Performance of Regulated Utilities to the S&P500



Source: Factset, UBS Equity Research

We believe the underperformance represents a buyable pullback for three reasons.

1. The measure for absolute value in RUs is long term interest rates. The recent pullback leaves RUs undervalued vs rates for the first time since the spring of 2013.

2. The gauge of relative value for RUs vs the broader market is comparative price to earnings ratios. Here too, the pullback leaves the group at the doorstep of undervalued, and fund flow data is showing signs that sellers are getting exhausted.

3. It is our opinion that bear markets rarely start with improving group fundamentals. For RUs, the fundamental backdrop defined by investment visibility, the ability to manage customer rate inflation and a constructive regulatory and policy backdrop for infrastructure has rarely been better.

With this setup, we recommend adding to RU positions, but slowly over the next two quarters for two reasons. First, RUs are likely to lag during the earnings revision cycle for the market when tax reform is incorporated into estimates. Due to regulation, most of the benefits of tax reform for Utilities will be passed to customers and not show up as higher earnings per share. Second, there is significant controversy about the direction and magnitude of interest rate moves in 2018. As an interest sensitive sector, periods of controversy such as this tend to keep investors on the sidelines regardless of valuation.

Regulated Electric Utilities are Bonds – Cheap Bonds

Regulated Utilities are defensive, low beta, high yielding investments. In fact, the best reason to have RUs in a stock portfolio is for their risk reduction qualities. As the heat map below demonstrates, among the S&P sub sectors, RUs have the second highest dividend yield, the lowest benchmark Beta, the most negatively correlated rates Beta, and a downside Beta that shows outperformance and an upside Beta that lags the market.

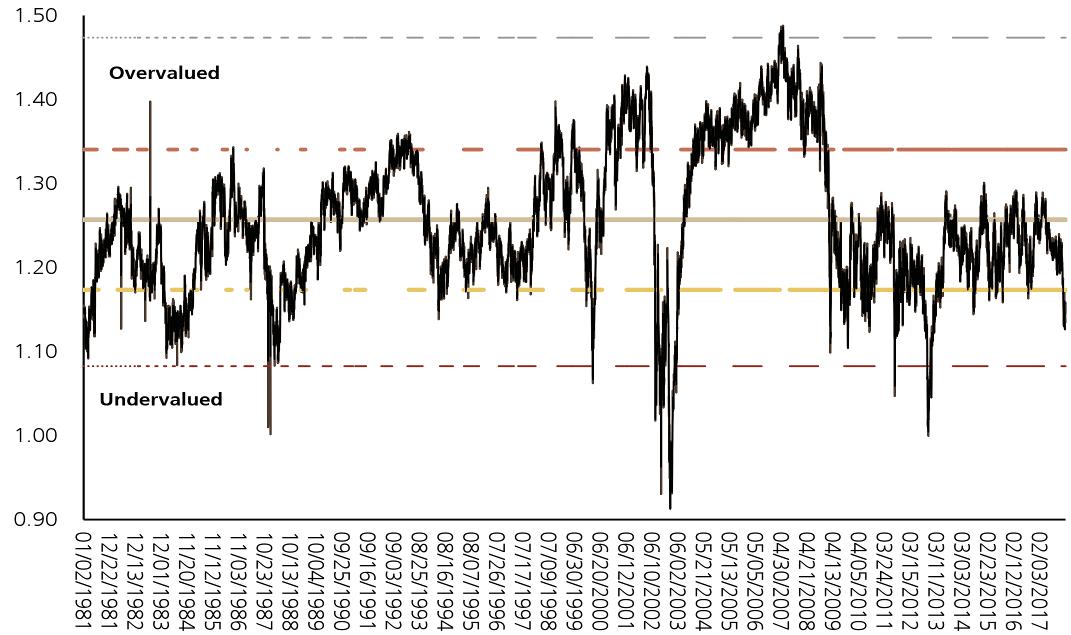
Figure 4: Relevant Stock Drivers by Sector, Utilities Screen Defensive

Sector	Yield	Benchmark Beta	Rates beta	Downside beta	Upside beta
Automobiles & Components	3.4	1.43	0.244	1.488	1.378
Banks	2.3	1.32	1.142	1.440	1.211
Capital Goods	2.0	1.12	0.103	0.965	1.248
Commercial & Professional Services	1.8	0.90	-0.060	0.784	1.005
Consumer Durables & Apparel	1.6	1.03	0.117	0.948	1.106
Consumer Services	2.0	0.76	0.052	0.766	0.764
Diversified Financials	1.2	1.24	0.502	1.221	1.247
Energy	2.9	1.20	-0.030	1.169	1.229
Food & Staples Retailing	2.1	0.72	-0.184	0.637	0.795
Food, Beverage & Tobacco	3.1	0.58	-0.443	0.523	0.637
Health Care Equipment & Services	1.0	0.90	-0.026	1.095	0.742
Household & Personal Products	2.8	0.53	-0.460	0.543	0.520
Insurance	2.1	1.10	0.314	1.038	1.154
Materials	2.0	1.20	0.065	1.076	1.298
Media	1.6	1.01	0.051	0.876	1.116
Pharmaceuticals, Biotechnology & Life Sciences	2.1	1.00	-0.014	1.054	0.949
Real Estate	3.5	0.73	-0.797	0.577	0.860
Retailing	0.9	1.04	0.027	1.010	1.072
Semiconductors & Semiconductor Equipment	1.8	1.27	0.114	1.397	1.157
Software & Services	0.9	1.03	-0.045	1.114	0.964
Technology Hardware & Equipment	1.9	1.01	-0.055	1.128	0.907
Telecommunication Services	5.1	0.62	-0.118	0.487	0.738
Transportation	1.7	1.18	0.244	0.918	1.393
Utilities	**3.7**	**0.42**	**-0.964**	**0.356**	**0.472**

Source: UBS Quantitative Research, UBS Equity Research

It is natural that the driver for absolute valuation for this type of defensive vehicle is interest rates. Figure 3 maps the yield of the Baa corporate bond index to the average dividend yield of the RU sector. The correlation between utility dividend and Baa yields is high with an R^2 of 91%. Using 1 standard deviation as a measure of relative value, Utilities are considered inexpensive when Baa yields are 118% or less of the RU dividend income and expensive when they are 138% or higher. The mean of the relationship is 128%. In the last 6 weeks (12/21/17), regulated utilities crossed the line from fairly valued to attractive. The Baa is currently at 114% of the RU dividend yield. The last time this happened definitively was in the spring of 2013. A downside case from here is to the 2 standard deviation undervalued mark of 109%. The absolute cost would be 5% in price performance. A 2 standard deviation gap has only happened 5 times since 1981.

Figure 5: Relative Value of Baa Corporate Bond Yields vs. Regulated Utility Dividend Yields



NOTE: Straight lines indicate the mean, +/- 1 standard deviation, and +/- 2 standard deviations

Source: Factset, UBS Equity Research

All things equal, this implies that RUs are undervalued by 12% on an absolute basis and one might expect an annual total return of 15% including a dividend yield of 3.8%, if the relationship normalizes. Of course, this is only the case should corporate bond yields remain flat.

The risk to our bullish bias is a rise in long dated rates from here. Here we define that risk using the UBS rates forecast and our analysis of utility equity duration. UBS predicts a rise in benchmark 10 year treasury rates of 20 bp in 2018 to 2.9%. (See: Lesson Learned: Revising forecasts & taking stock, published January 31, 2018) To translate this to stock price risk, we use our calculation of regulated utility equity duration (see figure 4).

Figure 6: Equity Duration of Sector and Subgroups

SubCategory	Duration (Years)	Δ in Value +10bps
Electric Utilities	19	-1.90%
Large Cap	18	-1.80%
Smid Cap	20	-2.00%
Multi-Utilities	17	-1.70%

Source: Factset, UBS Equity Research

Using our calculations, a 10bp move in Baa bond rates will lower the value of utilities by approximately 2%, *ceterus peribus*. Putting all of this together in a prediction for the absolute performance for the RU sector in 2018, we calculate a 15% annual total return if rates remain where they are, and an 11% annual total return if long rates rise 20bp consistent with UBS' rates view. Where total return = 12% for a return to an average valuation relationship to Baa yields + an average dividend yield of 3.8% - 4% for the expected rise in the benchmark.

Will Federal Reserve Tightening Frustrate Performance?

The Federal Reserve Bank began a slow Federal Funds Rate hike cycle December 17, 2015. To date, there have been 5 raises on 12/17/15, 12/14/16, 3/15/17 and 6/14/17 and 12/3/17, totalling 125bp. UBS anticipates 3 more moves in 2018 with another 2 in 2019 (See: US Economic Comment: Modifying our Fed and inflation calls, published January 16, 2018). From our vantage point, this cycle is unusual in two ways. First it is extraordinarily long. Expectations are that by the time the Fed has completed its work, 4 years or more will have passed. Going back to 1980, there have been 7 other fed funds rate tightening cycles averaging 12 months with the longest being 25 months and the shortest 6 months. Second, today's moves are intended to normalize rates from an extremely accommodative stance, as opposed to past cycles that were intended to tighten rates and defeat rising inflation or decelerate an overheating economy or both. The net of this is that we are unsure what type of impact fed action may have on the performance of Utilities. However, we can offer the experience from the past as a loose model (see figure 5).

Figure 7: DJU vs. S&P 500 Performance During Fed Rate Hike Cycles Since 1980

	12 months prior to 1st Hike			Within Cycle 1st Hike to Last Hike			Last Hike to 12 months after		
Fed Hike Cycle	S&P 500	DJU	REL	S&P 500	DJU	REL	S&P 500	DJU	REL
June '80 - May '81	16.34%	0.97%	-15.38%	7.68%	-1.96%	-9.64%	-13.84%	5.54%	19.38%
May '83 - July '84	44.21%	15.01%	-29.20%	-10.70%	-5.55%	5.16%	29.60%	27.69%	-1.91%
April '87 - September '87	16.32%	6.77%	-9.55%	12.50%	1.10%	-11.40%	-16.49%	-10.36%	6.13%
March '88 - February '89	-12.33%	-20.74%	-8.41%	9.03%	4.25%	-4.78%	12.89%	19.26%	6.37%
February '94 - February '95	4.50%	-5.96%	-10.46%	0.13%	-12.48%	-12.61%	35.21%	19.79%	-15.42%
June '99 - May '00	18.71%	10.25%	-8.45%	8.48%	2.24%	-6.24%	-12.35%	17.55%	29.90%
June '04 - June '06	16.59%	10.21%	-6.38%	12.03%	49.25%	37.22%	18.11%	20.67%	2.56%
December '15 - Present	1.44%	-4.57%	-6.01%	37.03%	18.98%	-18.05%			
Average Performance	13.22%	1.49%	-11.73%	9.52%	6.98%	-2.54%	7.59%	14.31%	6.71%
AVG w/o current cycle	14.91%	2.36%	**-12.55%**	5.59%	5.26%	**-0.33%**	7.59%	14.31%	**6.71%**

Source: Factset, Bloomberg, US Federal Reserve, UBS Equity Research

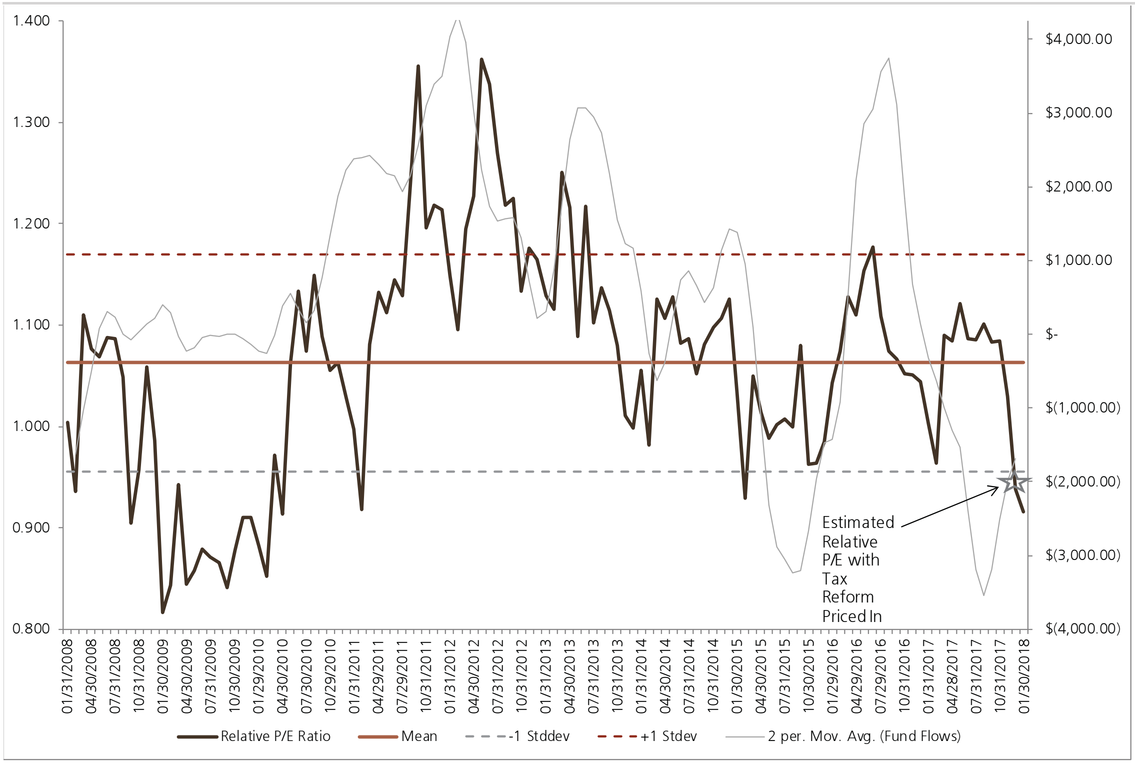
During past Fed tightening episodes, RUs underperformed the S&P 500 in the 12 months prior to action by 12.5%, performed in line with the S&P 500 during the hikes (-0.33%), and outperformed for the 12 months following the last hike by 6.7% on average. As for frequency, RU's underperformed in all 7 periods leading into the first hike. During the action, the group underperformed four times, outperformed once and were +/- 5% or less twice. Exiting, RU's outperformed four times, unperformed once, and were inside +/-5% twice.

From this data, our conclusion is a bit muddled. On the optimistic side, one could argue that the average neutral relative performance of RU's during a Fed hike cycle argues in favour of the attractive relative value of the group being rewarded. On the pessimistic side, the frequency of underperformance during past programs suggests an overall negative performance bias could persist. However, given that RUs have already lost 18% to the S&5 500 since 12/15, exceeding the previous worst performance during a cycle by 6+% with most of it coming in the last 3 months, we think that further downside is unlikely. Finally, over the period form 1980 until now, benchmark rates in general have declined. The result has been a significant lengthening of the equity duration of the RU group to almost 20 years from 7-8, 35 years ago. All things equal, the shape of the Treasury curve should matter more to RU performance than short term rates today. UBS is looking for a further flattening of rate structure in the US (see Lesson Learned: Revising forecasts & taking stock, January 31).

Regulated Electric Utilities are Cheap vs the Market, but there is an *

We use relative price to earnings ratios comparing RUs to the S&P500 to measure relative value of the group. We further inform this analysis by tracking fund flows of the long-term marginal investor for the space – Income funds. The table below shows the relationship between these two series.

Figure 6: Relative FY2 P/E Ratio of Regulated Utilities to the S&P 500 Since 2007, with Equity Income Fund Flows



Source: Factset, Strategic Insights, UBS Equity Research

We refer to this as the "Captain Obvious Chart." It happens that when the marginal buyer in the space is receiving new assets to put to work, RU's get relatively more expensive and conversely when funds are flowing out, the space becomes relatively cheaper. There are two pieces of good news in the chart today. First, on a relative value basis, RUs crossed the 1 standard deviation mark at 96% and are 13.8% cheap on price to the mean of 106%. Second, in spite of recording 12 consecutive months of outflows, sellers of income funds appear to be reaching exhaustion and the pace of selling has slowed. Our hesitation to pound the table, however, is the looming S&P earnings revision taking place in 1Q, as corporates provide guidance incorporating tax reform. UBS's Strategist Keith Parker estimates that there may be another 2.2% uptick in corporate EPS vs consensus estimates. Unfortunately, utilities will see almost no revision by comparison. If we adjust the chart to reflect this expectation, the group falls at the buy signal.

Fundamentals are Strong

It is our experience that industry fundamentals for RUs are a function of meeting the competing needs of three constituents. These are: 1)The shareholders who want robust dividend and earnings growth fueled by a visible capex backlog; 2)The customer who wants reliable service at an affordable price; and 3) The Regulator/Policymaker who wants to provide for a strong local economy that meets increasing environmental policy mandates at a reasonable cost. Considering these desires, the tools we use to assess how good or bad things are, include our Capex Survey; Rate affordability and inflation analysis, and Regulatory Trends and Ranking work.

Capex Survey Backs Robust Growth Expectation

RUs are cost plus regulated in the US. This means that revenues are set to allow a company to pass through prudently incurred operating costs, taxes and fuel to customers and receive recovery of and a debt and equity return on net capital investment. This net capital investment is known as rate base. Therefore earnings and dividends (a function of earnings) grow based on capital expenditure plans and needs. Figure 7 is our capex expectations for the companies we are initiating on today.

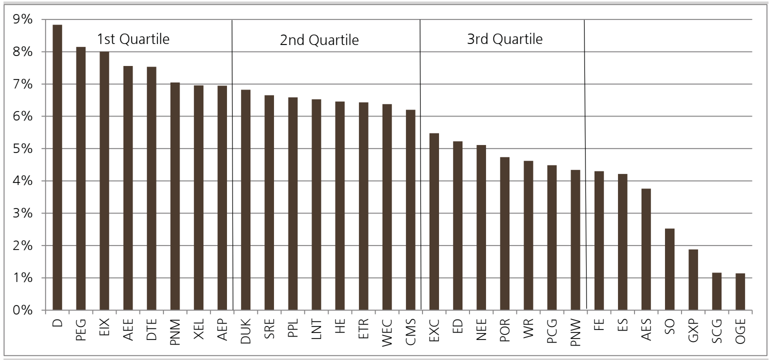
Figure 7: Regulated Utility Universe Cap-Ex and Rate Base Forecast (US$m)

	2016A	2017E	2018E	2019E	2020E	2021E	2022E
Maintenance cap-ex, distribution		$41,667	$44,973	$46,258	$45,381	$44,710	$45,412
Transmission		$13,755	$13,912	$13,117	$12,728	$12,565	$12,658
Generation		$15,573	$15,094	$15,199	$12,664	$11,589	$10,872
Environmental		$3,347	$2,771	$1,478	$1,333	$1,622	$1,622
Grid-Modernization		$1,094	$2,130	$1,828	$1,748	$2,034	$2,043
UBS Universe Cap-ex	$69,439	$75,437	$78,880	$77,881	$73,855	$72,519	$72,608
Year over Year		8.6%	4.6%	-1.3%	-5.2%	-1.8%	0.1%
Rolling 3 year		4.3%	3.0%	3.8%	-0.7%	-2.8%	-2.4%
	2016A	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**
Starting Ratebase	$544,232	$571,406	$606,410	$650,302	$690,887	$725,473	$756,924
Capital Expenditures	$69,439	$75,437	$78,880	$77,881	$73,855	$72,519	$72,608
Depreciation	-$30,113	-$32,502	-$34,988	-$37,295	-$39,269	-$41,069	-$42,780
Bonus Depreciation	-$12,152	-$7,932	$0	$0	$0	$0	$0
Ratebase Additions	$27,174	$35,003	$43,893	$40,585	$34,586	$31,451	$29,828
Ending Ratebase	$571,406	$606,410	$650,302	$690,887	$725,473	$756,924	$786,751
Year over Year		6.1%	7.2%	6.2%	5.0%	4.3%	3.9%
2017-2022				5.3%			

Source: Company Reports & SEC Filings, S&P Global Market Intelligence, UBS Equity Research

The capex survey is backwardated. This is typical, as near term spending is more certain than longer term projects. However, on a 5 year basis, the average growth expectation is 5.3%. This is close to the middle of EPS guidance and 5 year consensus estimates for RU EPS (4.2%) and DPS (5.3%) growth. The set-up is quite bullish. As visibility for out-year spending improve with time, the capital outlays in years 3, 4 and 5 are likely to rise. Therefore, we believe there is a bias over the long term for RU estimates to be revised higher. Even if they are not, 5.3% growth combined with a group average dividend yield of 3.8% results in a simple annual total return expectation of 9.1%. This should meet expectations for returns for a low volatility sector.

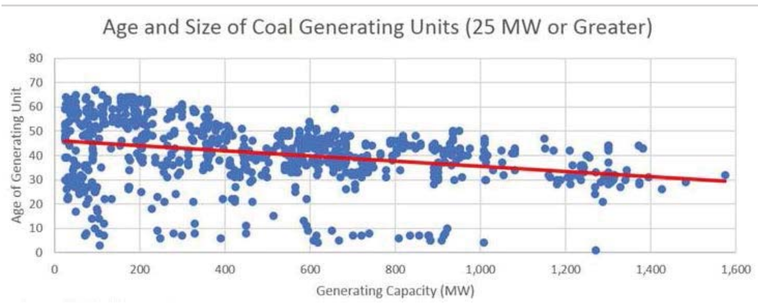
Figure 8: Regulated Utility Universe Cap-Ex and Rate Base Forecast



Source: Company Reports & SEC Filings, S&P Global Market Intelligence, UBS Equity Research

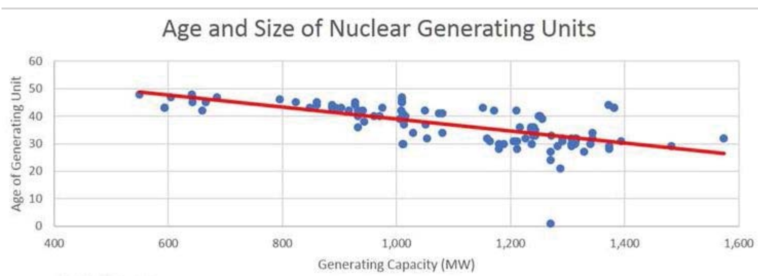
We can identify several reasons for ample capital deployment opportunities. First, the age of the system is high. On average the distribution wires have been in the air for decades, gas distribution pipes until the last few years were on replacement cycles of 60-100 years, and 70% of the grid's transmission lines and power transformers were over 25 years old as of the 2013 White House report on electric grid resilience. The average age for the coal generation fleet is 41 years and for nuclear plants is 37 years as shown below in Figures 9 and 10.

Figure 9: Average Age of 789 Coal Units Greater than 25MW Capacity



Source: Edison Electric Institute, ABB, The Velocity Suite, UBS Equity Research

Figure 10: Average Age of 99 Nuclear Units



Source: Edison Electric Institute, ABB, The Velocity Suite, UBS Equity Research

Systematic replacement is necessary and underway. Second, public policy mandates to improve the environmental profile of the electric system are forcing generating plant retrofits, and early retirement. Older facilities are being replaced with modern gas plants and renewables. Emerging technologies that improve efficiency, communication capability, and reliability of the grid are also finding their way into backlogs. Finally cyber and physical security of the grid is driving spending too.

When we break rate base growth down by company and valuation, the industry looks like Figure 11. In order to occupy the first quartile, a utility has to drive 7.0%+ 5-year net investment growth and trades at a FY2 price to earnings premium of 7.8% to the group. Second quartile drives net investment growth of between 5.3% and 7% and commands a 6.3% p/e premium. Third quartile has between 4% and 5.3% growth and trades at a 2.7% discount p/e to the group. Finally fourth quartile growers average below 4% and receive a 7% p/e discount.

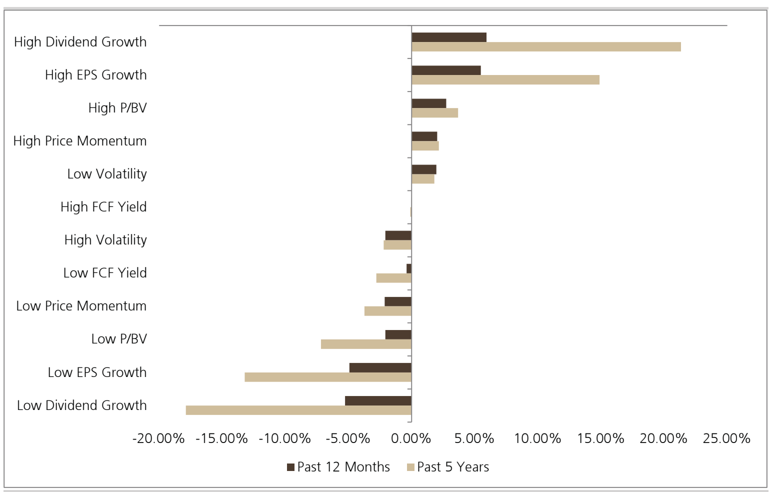
Figure 11: FY2 P/E Ratio by Rate Base Growth Quality Quartile

Quality Quartile	Low Growth	High Growth	Current Growth	Current P/E	Current Prem/Disc	Prem/Disc. in Methodology
1st	7.00%		8.0%	17.3x	7.8%	5%
2nd	5.30%	7.00%	6.2%	17.0x	6.3%	2%
3rd	4.00%	5.30%	4.6%	15.6x	-2.7%	-2%
4th	0.00%	4.00%	1.6%	14.9x	-7.0%	-5%
AVG			5.3%	16.0x		

Source: Company Reports & SEC Filings, S&P Global Market Intelligence, UBS Equity Research

Spending visibility and rate base growth also directly impact dividend growth. Utilities typically set dividend payment rates at a targeted percentage of earnings or at a growth rate consistent with earnings growth. Today the average payout ratio for utilities is 58%. As can be observed in figure 12 developed by UBS quantitative research group, RU price performance is most closely aligned with dividend and earnings growth rates over time. We incorporate the growth visibility directly into our valuation framework (see Valuation Methodology section below). The premia and discounts we apply can also be found in the last column of figure 11.

Figure 12: Performance by Style for RUs, LTM and Last 5 Years



Source: UBS Quantitative Research Team, UBS Equity Research

Customer Affordability Looks Manageable

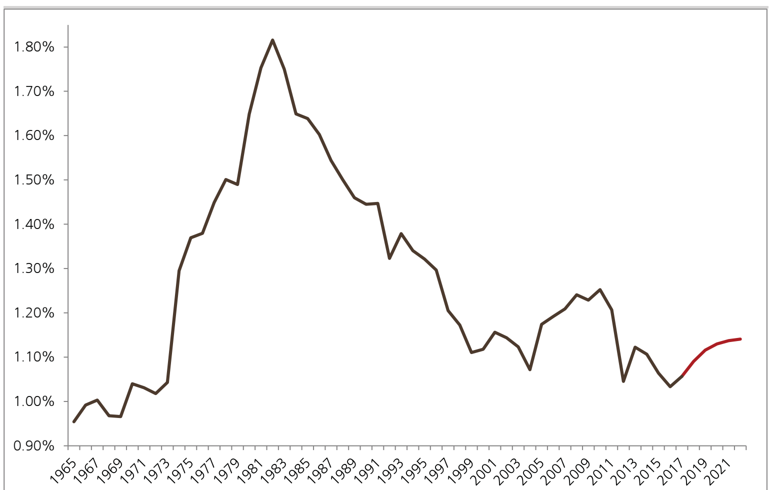
For rate base and earnings growth to continue at the pace described above, customer bill inflation must be held in check. Otherwise, ratepayer revolt can quickly pinch off capital deployment plans via regulatory pushback. The challenge is particularly vexing with the absence of meaningful kWh sales growth for the industry over the last decade (see figure 13). There are four reasons that we are comfortable with the current trajectory of rate inflation. First, electric bills are low as a percentage of consumer spending. In 2016, Electricity commanded 1.03% of consumer spending, the lowest since 1972 (see figure 14). Second, Utility operational efficiency is improving creating headroom for additional capital to be deployed (see figure 15). Third, Federal Tax Reform will lower the bill for regulated companies. Finally, while we are not counting on it in our forecasts, the deployment of electric vehicles and other efficient electrification application may result in some return to sales growth in the future.

Figure 13: U.S. GDP Growth and Average Electricity Demand Growth by Decade

Period	Avg GDP Growth	Avg Electricity Growth	Correlation
1950 - 1960	4.10%	9.54%	85.0%
1961 - 1970	4.29%	7.31%	45.1%
1971 - 1980	3.20%	4.20%	83.3%
1981 - 1990	3.36%	3.11%	79.7%
1991 - 2000	3.45%	2.39%	10.7%
2001 - 2010	1.66%	0.81%	79.0%
2011 - 2016	2.07%	0.07%	-6.9%
TOTAL	3.24%	4.23%	68.3%
1950 - 2010	3.35%	4.64%	68.0%
1971 - 2010	2.92%	2.63%	74.7%
2011 - 2016	2.07%	0.07%	-6.9%

Source: Factset, US Bureau of Economic Analysis, Energy Information Administration, UBS Equity Research

Figure 14: Electricity as a % of Disposable Income 1965-2016 Actual, 2017 – 2022 Forecast

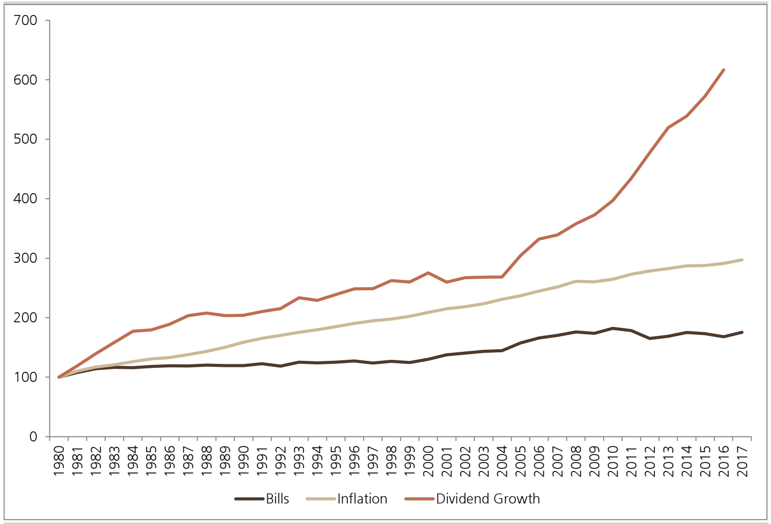


NOTE: Red Line indicates forecast

Source: US Bureau of Economic Analysis, Energy Information Administration, UBS Equity Research

Of course, rate of change can raise a response from customers regardless of the starting point. Here, a combination of improved business practices, deployment of modern work management systems, synergies from consolidation and restructuring of employee benefits are all tools to create headroom for added investment. As a rule of thumb, every $1 of operating cost reduction translates into $7-$9 of capital deployment without a rate increase.

Figure 15: Increase in Electricity Bills, Inflation, and Annual Utility Dividends Since 1980



Source: US Bureau of Economic Analysis, Energy Information Administration, Factset, UBS Equity Research

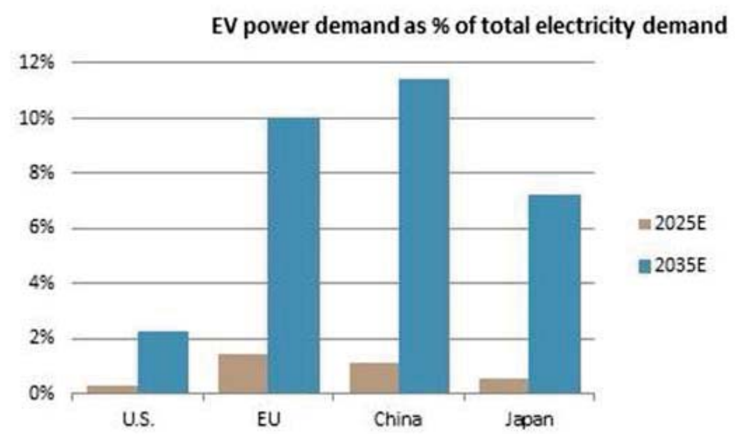
In the short run, there is also the benefit of Federal Tax Reform for RU customers. Under regulation, tax is a pass-through to customers. The reduction in the federal marginal rate will, therefore, lower the bill for most RU's. The exact timing of those rate adjustments will vary by jurisdiction, but most are likely to happen early in 2018. There will be more detail on the impact of tax reform in a later section of this report, but overall, we estimate that the typical utility customer will see a 1.9% reduction due to tax reform.

Electricity Demand Growth Left for Dead?

While we do not include it in our company forecasts, there are several exciting emerging electric technologies that could increase demand growth while lowering global CO2 and other pollutant emissions in the future. Most of these have insignificant impact on electric sales growth potential over the next 5 years, but could contribute over a 10 to 15 year horizon. The most promising of these include Electric Vehicles, Indoor Farming, efficient Heat Pumps for HVAC, and Induction heating for industrial processes. In many cases, leadership in deployment will be in non-US markets. The reason for this is both because many foreign markets have more aggressive environmental regulation than the US, and because the price of electricity is much higher abroad, shortening the timeline for emerging technologies to become economic choices.

On January 2, our global utility research counterparts with proprietary inputs from UBS Evidence Lab published a report, *Global Utilities: UBS Evidence Lab: How will the growth in EVs impact global utilities?* The report examines a range of potential implications of rising EV penetration. On the topic of Kwh sales growth, it concludes that the potential impact on demand is small in the short run, now until 2025, but could be meaningful over the longer term, now until 2035, globally (see figure 16).

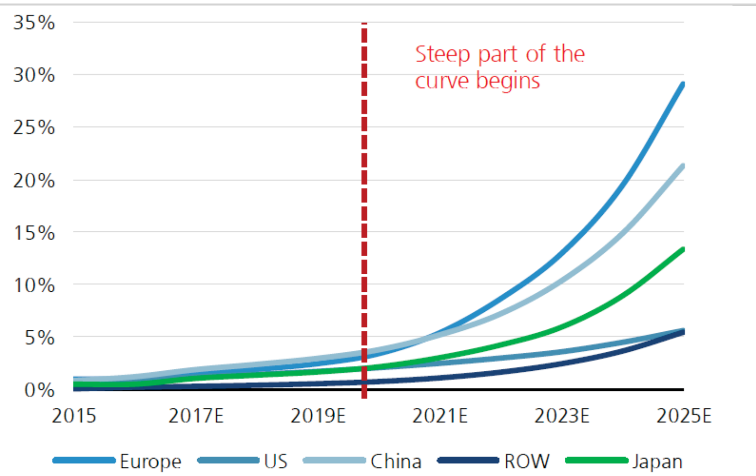
Figure 16: Incremental power demand for EVs is relatively low until after 2025



Source: "UBS Evidence Lab: How will the growth in EVs impact global utilities?", Published January 2 2018, UBS Equity Research

The US has the least to gain as a region, however. Adoption rates in the US are expected to be lower than abroad. Overall, UBS forecasts that global EV sales will move from 1.6% of overall new light vehicles in 2018 to 15.8% in 2025. By contrast, the projection only calls for an expansion in the US from 1.4% in 2018 to 5.6% in 2025 (see figure 17).

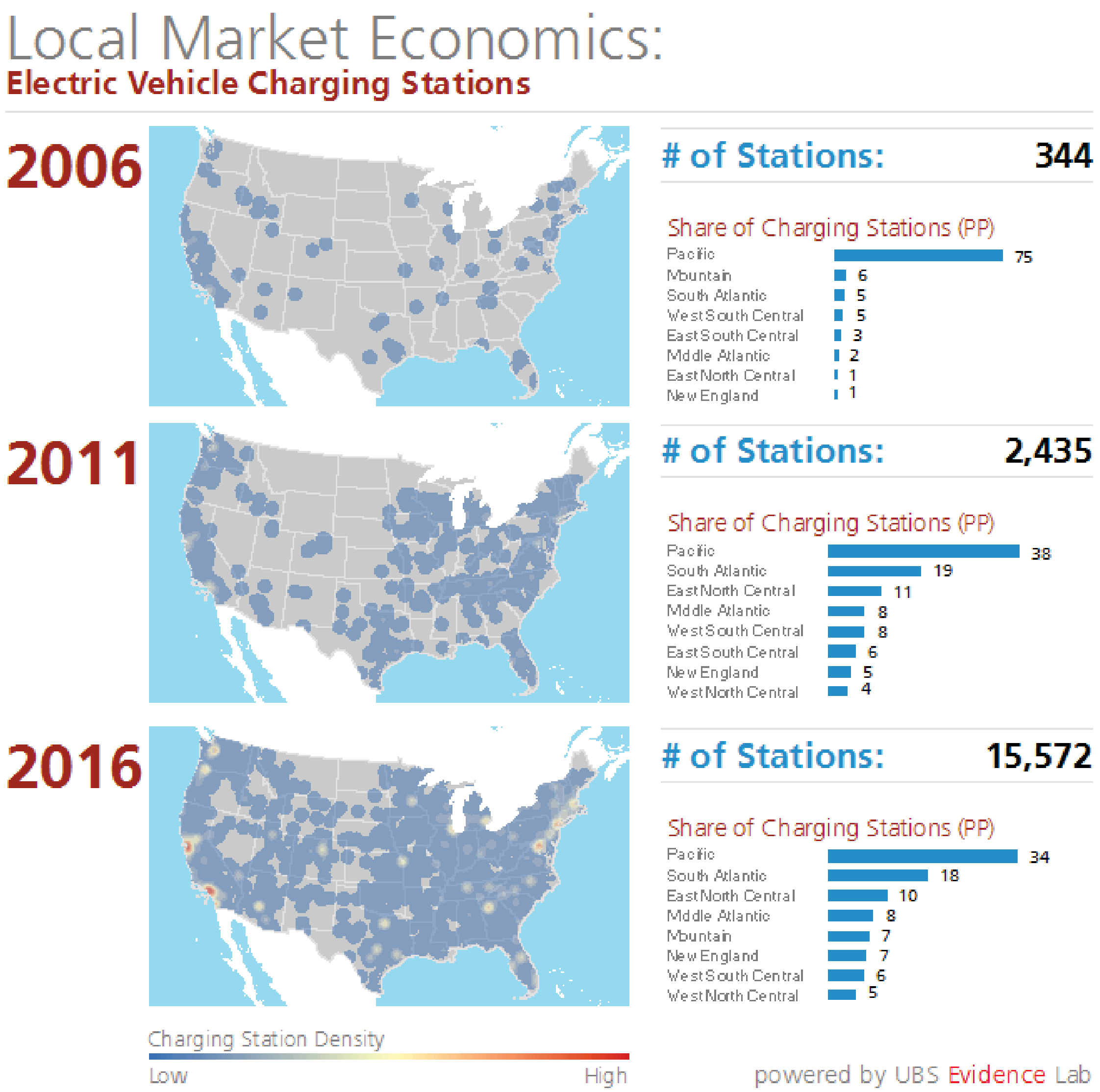
Figure 17: EV share of new car sales by region (EV sales as % of total car sales)



Source: "UBS Evidence Lab: How will the growth in EVs impact global utilities?", Published January 2 2018, UBS Equity Research

An interesting overlay on this subdued average impact on US electric sales is that the concentration of EV's is likely to be very uneven. The map in figure 17 shows that EV charging infrastructure is disproportionately located in and around the West and East Coasts. This clustering could mean significantly more meaningful impact on those locations (see figure 18).

Figure 18: EV registration per capita in the United States



Source: "UBS Evidence Lab: How will the growth in EVs impact global utilities?", Published January 2 2018, UBS Equity Research

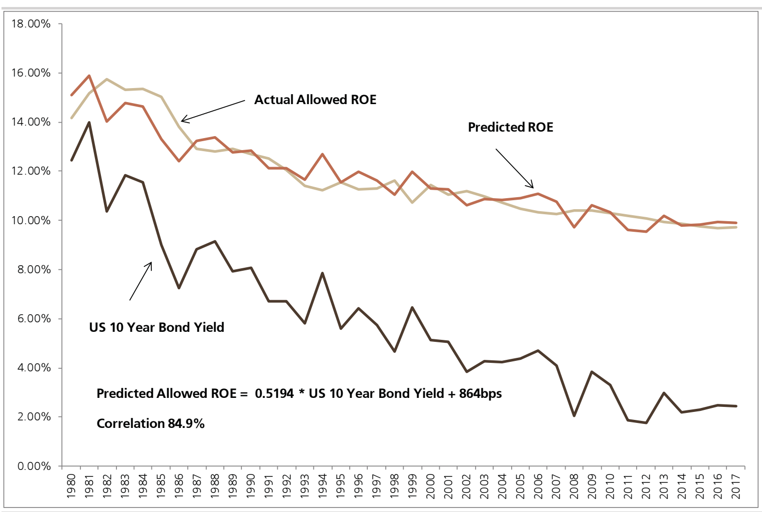
Over the coming year, we expect to examine the potential for efficient electrification to change demand growth expectation, infrastructure needs, and disruptive threats for the utility industry. In pursuing this work, we will draw from the impressive global analytical talent at UBS as well as from the tools UBS Evidence Lab brings to the table. Stay tuned.

Regulatory Trends Generally Constructive

Regulation of RUs in the US is dominated by State commissions. Overall the States are responsible for the regulation of distribution systems and regulated generation. This represents approximately 90% of utility assets. The Federal Energy Regulatory Commission is responsible for transmission and interstate pipelines. Over the last two decades, we would generally describe regulation in the US as fair to shareholders and on an improving trend. For investors, the two most important factors influencing equity performance relating to regulation are the allowed returns granted and differences between the policies and practices in each jurisdiction that contribute to the risk associated with owning each company.

Nationally, allowed returns on equity are a function of interest rates. Absolute allowed returns have been on a downward trajectory since Treasury yields last peaked in the early 1980's. In 1981, the average allowed return on equity for the RU sector was 15.19%. Over the trailing 12 months it has averaged 9.73%. On the surface this seems like bad news for investors, but it is not. As referenced in the prior sections, declining cost of capital creates headroom for investment, and utilities are bond like equities. What has really driven utility values is the spread between allowed returns and the risk free rate coupled with productive investment that covers RU cost of capital. As a proxy for the risk free rate we use the US 10-year Treasury note. As can be seen in figure 18, the return spread has been rising as rates have fallen. In the trailing 12 months, RU's have been allowed a 730bp return spread compared to 121bp in 1981. In conclusion, so long as rates stay relatively low, as is our assumption, regulation supports robust investment and growth by participant companies.

Figure 19: Regulated Allowed ROE vs. 10 Year Bond Yield



Source: Factset, S&P Global Market Intelligence, UBS Equity Research

Not all jurisdictions treat their utilities the same. The differences between jurisdictional regulatory practices are a primary factor in determining relative value between companies, their growth rates and allowed and earned returns. We rank each jurisdiction using 6 equally weighted criteria. These are as follows

1) **Elected vs Appointed Commissions:** Elected commissioners tend to focus more closely on managing customer affordability which can

dampen investment vs appointed commissions that tend to be more policy driven, all else equal.

2) **Allowed Return Spread:** We measure the return spread over 10-year Treasury note of the ordered rate cases since 2010 by jurisdiction. As rate of return setting policies and practices are grounded in decades of case law, jurisdictions that allow high and low return spreads tend to continue with that practice.

3) **Mechanisms that Reduce Regulatory Lag:** Regulatory lag is the difference between authorized returns on equity and earned returns resulting from time lag between dollars invested in rate base and authorized revenues reflecting that spending. With the advent of computing power, several techniques to reduce rate lag have been incorporated into regulation, including tracking mechanisms, forward test years, formula rate plans and performance based regulation. Adoption has been uneven, so it is in the interest of investors to favour places that minimize lag.

4) **Rate and Customer Bill Levels:** Utilities' prices are often a material factor in state economic development. States with high prices vs its surroundings tend to scrutinize utility investment more closely than states with low bills.

5) **Tendency to Settle vs Litigate Rate Cases:** Settlements have the advantage of being quicker, less risky and less prone to legal appeal than fully litigated rate proceedings. States that regularly settle are preferred by investors.

6) **UBS subjective Investor Friendliness Factor:** Based on our knowledge of current commission actions, we skew the results by up to 1/6th.

The results of our rankings are presented as a bell curve in Figure 20. Overall, we find most regulation in the US to be fair. Outliers on the positive side present a lower cost of capital business environment and encourage investment in utility infrastructure. By contrast, higher cost of capital states discourages investment. We also show the S&P Global Market Intelligence rankings of the jurisdictions as a proxy for the consensus view, and have organized them into similar tiers as indicated in the note in Figure 21. The jurisdictions where we differ by more than two tiers to the S&P Global Market Intelligence rankings are Colorado (two tiers higher), and Mississippi, Nebraska, Hawaii, and Vermont (two tiers lower).

Figure 20: UBS Regulatory Jurisdiction Rankings

TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
		Idaho		
FERC		Oregon		
		Louisiana		
		Kentucky		
		South Carolina		
		Washington		
		Texas		
		Rhode Island		
		Tennessee		
	Pennsylvania	Wyoming	Delaware	
	Utah	New Hampshire	Nebraska	
	Georgia	New York	Oklahoma	
	Illinois	California	West Virginia	
Florida	Arkansas	Minnesota	Alaska	Montana
Michigan	Indiana	Kansas	Missouri	Hawaii
Wisconsin	Ohio	Nevada	Connecticut	Maryland
North Carolina	Virginia	New Jersey	South Dakota	New Mexico
Colorado	Iowa	Arizona	Maine	Vermont
Alabama	North Dakota	Massachusetts	Mississippi	District of Columbia
JD Power Average Customer Service Scores				
726	725	706	702	695

Source: S&P Global Market Intelligence, Factset, JD Power, UBS Equity Research

Figure 21: S&P Global Market Intelligence Regulatory Jurisdiction Rankings

TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
		Arizona		
		Colorado		
		Delaware		
		Hawaii		
		Idaho		
		Illinois		
		Louisiana		
		Massachusetts		
	Arkansas	Maine		
	California	Minnesota		
	Iowa	New Hampshire		
	Indiana	Nevada		
	Kentucky	Ohio		
	Michigan	Oklahoma		
	Mississippi	Oregon	Alaska	
	North Carolina	Rhode Island	Connecticut	
	North Dakota	South Carolina	Kansas	
Alabama	Nebraska	South Dakota	Missouri	
Florida	New York	Texas	Montana	
Georgia	Pennsylvania	Vermont	New Jersey	
Virginia	Tennessee	Washington	New Mexico	District of Columbia
Wisconsin	Utah	Wyoming	West Virginia	Maryland

NOTE: S&P Global Market Intelligence Rankings – Tier 1 = Above Average/1, Above Average/2; Tier 2 = Above Average/3, Average/1; Tier 3 = Average/2, Average/3; Tier 4 = Below Average/1, Below Average/2, Tier 5 = Below Average/3

Source: S&P Global Market Intelligence, UBS Equity Research

The following table shows how each ranking quartile delivers for shareholders. Here we show the earned ROE, the projected rate base growth and relative price to book ratios that correspond with the rankings.

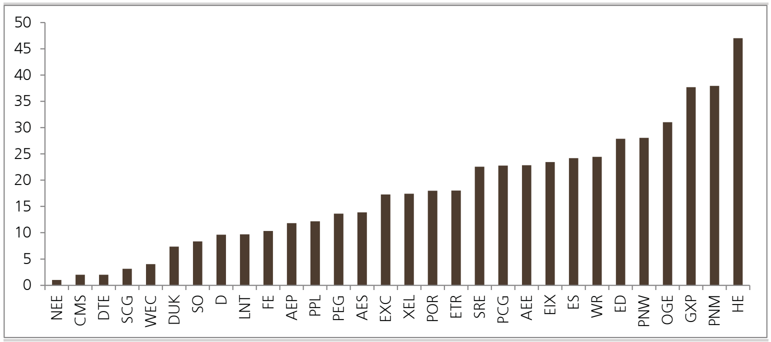
Figure 22: Regulated Utility Metrics for Rate Base Growth Quartiles

Metric	1st Quartile	2nd Quartile	3rd Quartile	4th Quartile
Ratebase Growth '17-'22	7.6%	6.4%	4.8%	2.7%
Price/Book	2.13x	1.83x	1.60x	1.60x
Earned ROE	11.9%	10.3%	9.4%	9.2%

Source: Factset, S&P Global Market Intelligence, UBS Equity Research

Finally, the last chart in this section arrays the group by weighted average regulatory ranking. The lower the bar the better the average quality of a company's regulatory environment. We incorporate the relationship between quality regulations directly in our valuation framework (see Valuation Methodology section below).

Figure 23: Company Average Regulatory Ranking



Source: S&P Global Market Intelligence, UBS Equity Research

Tax: A Mullet for RU's

In spite of our constructive view on the RU group, we do see the implications of Tax Reform as an impediment to investment returns for the first 1-2 quarters of 2018. Tax is a pass-through to customers for regulated entities. As a result, we don't expect a material earnings revision positive or negative for the average company we cover. Further the end of Bonus Depreciation for RUs will reduce near term cash flows. But on the good news front, tax reform will lower the average customer bill creating headroom for capital investment and that capital investment will translate to higher rate base and earnings growth over the long term without being reduced by immediate expensing. Our prediction for the overall impact of tax reform for the RU group is shown in Figure 24.

Figure 24: Regulated Utility Impacts Pre and Post Tax Reform

Metric	Pre-Tax Reform	Post-Tax Reform	Change
Consolidated EPS-2018	$3.47	$3.48	0.2%
Consolidated Cash Flow-2018			-1.5%
Ratebase Growth'17-'22			1.1%
Customer Price			-1.9%

Source: Factset, S&P Global Market Intelligence, UBS Equity Research

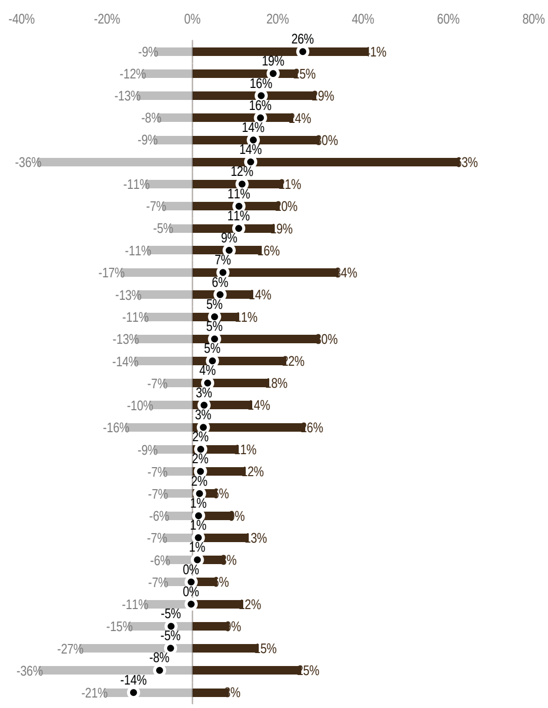
By contrast, UBS's Strategist Keith Parker expects the S&P500 consensus to experience a 4.7% upward earnings revision. Most of this will take place in the first quarter as companies calibrate investors for the impact of tax changes on their year-end calls.

Stock Recommendations for Investors

We are initiating coverage on 30 RUs today. We have 8 Buys, 4 Sells and 18 Neutrals. Our recommendations fall into three categories: 1) High quality total return compounders – AEP and DUK; 2) Higher growth Multi-Utilities - D, NEE and SRE; and 3) Values with a catalyst in 2018 - EXC, FE, and PPL. Figure 25 is our valuation table sorted by 12 month total return to our price targets.

Figure 25: Regulated Utility Upside Downside Summary

% difference from current price to
← downside ● base case upside → scenarios



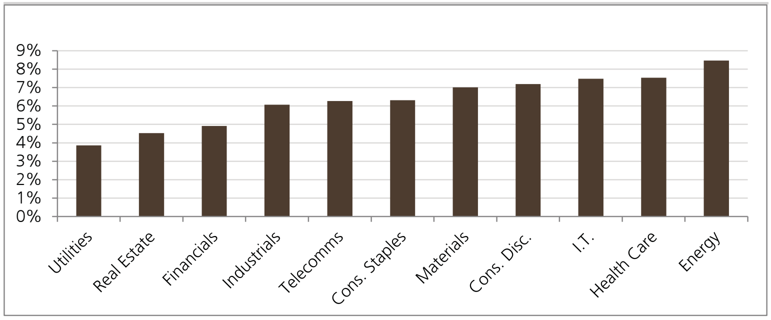
	downside	base case	upside	upside downside skew ↑ ↓	
PPL Corporation	-9%	26%	41%	5 to 1	Buy
FirstEnergy Corp	-12%	19%	25%	2.1 to 1	Buy
Sempra Energy	-13%	16%	29%	2.2 to 1	Buy
Duke Energy	-8%	16%	24%	2.8 to 1	Buy
Exelon	-9%	14%	30%	3 to 1	Buy
PG&E Corp	-36%	14%	63%	1.7 to 1	Neutral
NextEra Energy	-11%	12%	21%	1.9 to 1	Buy
Dominion Energy	-7%	11%	20%	2.9 to 1	Buy
American Electric Power	-5%	11%	19%	4 to 1	Buy
CMS Energy	-11%	9%	16%	1.5 to 1	Neutral
Edison International	-17%	7%	34%	2.0 to 1	Neutral
Westar Energy	-13%	6%	14%	1.1 to 1	Neutral
Eversource Energy	-11%	5%	11%	1 to 1	Neutral
AES Corp	-13%	5%	30%	2.2 to 1	Neutral
Entergy Corp	-14%	5%	22%	1.6 to 1	Neutral
OGE Energy Corp	-7%	4%	18%	2.6 to 1	Neutral
Xcel Energy	-10%	3%	14%	1.4 to 1	Neutral
Southern Company	-16%	3%	26%	1.7 to 1	Neutral
DTE Energy	-9%	2%	11%	1.2 to 1	Neutral
Great Plains Energy	-7%	2%	12%	1.8 to 1	Neutral
WEC Energy Group	-7%	2%	[illegible]%	1 to 1.2	Neutral
Ameren Corp	-6%	1%	[illegible]%	1.5 to 1	Neutral
Alliant Energy	-7%	1%	13%	1.9 to 1	Neutral
Pinacle West Capital Corp	-6%	1%	[illegible]%	1.2 to 1	Neutral
Consolidated Edison	-7%	0%	[illegible]%	1 to 1.2	Neutral
Public Service Ent Group	-11%	0%	12%	1 to 1	Neutral
Portland General	-15%	-5%	[illegible]%	1 to 1.7	Sell
PNM Resources	-27%	-5%	15%	1 to 1.7	Sell
SCANA Corp	-36%	-8%	25%	1 to 1.4	Sell
Hawaiian Electric Industries	-21%	-14%	[illegible]%	1 to 2.5	Sell

Source: Factset, UBS Equity Research

The purpose behind our three categories of recommendations reflects the narrow dispersion in annual returns the RU group yields. Figure 25 shows annual dispersion compared to other sectors in the market. Our high quality total return category is meant for investors that find the industry valuation attractive and want options with low business risk and slightly better than average valuation. Our

Higher growth Multi-Utility recommendations seek to provide exposure to higher earnings and dividend growth by taking on exposure to unregulated energy investments at a mid-risk level. Our Value category is intended for utility investors with a higher risk appetite but that offer potential for a higher payoff.

Figure 26: Average Dispersion of Returns by Sector, last five years



Source: UBS Quant Team, UBS Equity Research

Valuation Methodology

Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 5 categories. These are as follows:

1. Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%.

2. Growth Adjustment: The greatest differentiator of performance in utilities is dividend and earnings growth rates (see figures 11 and 12). Therefore, we adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 5% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 5% discount.

3. Regulatory Adjustment: Our proprietary regulatory rankings correlate with price to book ratios over time. Price to book is the third most significant performance factor behind dividend and earnings growth (see figure 12). Our valuation adjustments for regulation are as follows: First quartile jurisdictions receive 5%, second quartile 2%, third quartile -2% and fourth quartile -5%.

4. Multi Utility Diversified Valuation: For multi utilities (those with more than 15% diversified or foreign earnings), we perform a sum-of-parts analysis applying business/region appropriate valuations to those diversified businesses. We list the $ per share value we attribute to those businesses in figure 27.

5. One-off Adjustments: In special situations, we value risk on an issue specific basis. Common areas where we apply such an adjustment would include: low risk T&D only companies, large project construction risk, legal risk, announced M&A completion risk, etc.

The matrix below outlines the adjustment we make for the companies we are initiating on today.

Figure 27: Valuation Methodology Matrix

Investment Opinion	Ticker	Overall Reg Group Premium Discount	Regulatory Quartile Premium Discount	Regulated EPS Growth Premium Discount	Company Specific Adjustments	Net Prem Disc for Regulated Valuation	Diversified Business Value
Neutral	AES	10%	2%	2%	(5%)	9%	$7
Neutral	LNT	10%	2%	2%	0%	14%	$0
Neutral	AEE	10%	(2%)	5%	0%	13%	$0
Buy	AEP	10%	2%	2%	0%	14%	$0
Neutral	CMS	10%	5%	5%	0%	20%	$0
Neutral	ED	10%	(5%)	(2%)	8%	11%	$0
Buy	D	10%	5%	2%	0%	17%	$42
Neutral	DTE	10%	5%	2%	0%	17%	$24
Buy	DUK	10%	5%	(2%)	0%	13%	$0
Neutral	EIX	10%	(2%)	(2%)	(14%)	(8%)	$0
Neutral	ETR	10%	(2%)	5%	(10%)	3%	$0
Neutral	ES	10%	(2%)	2%	8%	18%	$0
Buy	EXC	10%	2%	5%	0%	17%	$10
Buy	FE	10%	2%	(5%)	0%	7%	$0
Neutral	GXP	10%	(5%)	(5%)	5%	5%	$0
Sell	HE	10%	(5%)	(5%)	0%	0%	$10
Buy	NEE	10%	5%	5%	0%	20%	$85
Neutral	OGE	10%	(5%)	(5%)	0%	0%	$7
Neutral	PCG	10%	(2%)	(2%)	(31%)	(25%)	$0
Neutral	PNW	10%	(5%)	2%	0%	7%	$0
Sell	PNM	10%	(5%)	(5%)	8%	8%	$0
Sell	POR	10%	(2%)	(5%)	0%	3%	$0
Buy	PPL	10%	2%	5%	0%	17%	$20
Neutral	PEG	10%	2%	5%	0%	17%	$10
Sell	SCG	10%	5%	(5%)	0%	10%	$0
Buy	SRE	10%	(2%)	(2%)	0%	6%	$54
Neutral	SO	10%	5%	(5%)	(20%)	(10%)	$0
Neutral	WEC	10%	5%	2%	0%	17%	$0
Neutral	WR	10%	(5%)	5%	0%	10%	$0
Neutral	XEL	10%	2%	2%	0%	14%	$0

Source: Factset, UBS Equity Research

Active Ratings

Figure 28: Regulated Utility Active Rating Summary

Rating	Ticker	Current Price	UBS Price Target	Total Return inc. Div. Yld	UBS 2018 EPS	UBS 2019 EPS	UBS 2020 EPS	2019 P/E Ratio	2019 Prem/ Disc	Current Dividend Yield	5 Yr EPS Growth	5 Yr DPS Growth
Higher Quality Total Return Compounders												
Buy	DUK	$78.50	$91	20%	$4.74	$5.03	$5.18	15.6x	(3%)	4.54%	4.1%	4.0%
Buy	AEP	$68.78	$76	14%	$3.85	$4.18	$4.46	16.5x	3%	3.61%	6.3%	4.8%
Higher Growth Mutli-Utilities												
Buy	SRE	$107.02	$124	19%	$5.50	$6.21	$7.73	17.2x	8%	2.82%	10.2%	9.0%
Buy	D	$76.44	$85	15%	$4.19	$4.28	$4.45	17.9x	12%	4.37%	6.6%	10.0%
Buy	NEE	$158.42	$177	14%	$7.88	$8.41	$9.06	18.8x	18%	2.20%	9.3%	12.0%
Values with a Catalyst in 2018												
Buy	PPL	$31.87	$40	31%	$2.35	$2.47	$2.66	12.9x	(20%)	4.77%	5.6%	4.0%
Buy	FE	$32.90	$39	23%	$2.45	$2.40	$2.28	13.7x	(14%)	4.38%	(5.7%)	0.0%
Buy	EXC	$38.51	$44	17%	$2.91	$3.05	$2.85	12.6x	(21%)	3.17%	4.9%	5.3%
Sells												
Sell	SCG	$40.64	$38	(2%)	$3.42	$3.36	$3.55	12.1x	(25%)	6.03%	(1.0%)	6.5%
Sell	POR	$42.35	$40	(2%)	$2.38	$2.44	$2.55	17.4x	8%	3.02%	3.9%	6.5%
Sell	PNM	$38.10	$36	(2%)	$1.74	$2.09	$2.16	18.2x	14%	2.78%	3.9%	9.0%
Sell	HE	$34.11	$29	(10%)	$1.91	$1.92	$2.02	17.8x	11%	3.64%	6.3%	0.0%

Source: Factset, UBS Equity Research

Buy and Sell Stock Investment Highlights

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can AES achieve investment grade credit metrics in 2019?

Yes they can with execution of their plan. AES has reduced recourse debt by $2.0B over the last 5 years to $4.5B at September 30. AES plans to reduce debt further with use of $1.05B in proceeds from sale of the Philippines. With growth in subsidiary distributions on projects announced, AES should reach 3.5-4.0x recourse debt to parent free cash flow plus interest by 2019.

Q: What is the impact of tax reform?

The EPS impact is higher taxes of $0.05-$0.08/share primarily due to the exposure of $0.3B of non-deductible interest at the parent company somewhat offset by lower taxes on U.S. unregulated generation. AES' strategy to reduce the exposure is through debt reduction. Customers at DPL and IPL could receive a 3.2% rate cut or $45M using our analysis .

UBS VIEW

AES's strategy to simplify the company has materially improved the credit over the last several years and the stock looks 5% undervalued in the near-term on a sum of the parts basis. Additional asset sales could help reduce exposure to tax reform through delevering and improve valuation. However the outlook for approved and financed projects in the backlog is limited following the Alto Maipo project in 2019 and the Southland project in early 2021 which makes it challenging for AES to maintain its total return goals. We also see risk to completion of Alto Maipo which we model as a $0.04 contribution in 2019. An unknown but potentially positive value contributor is AES' Fluence partnership with Siemens on battery storage.

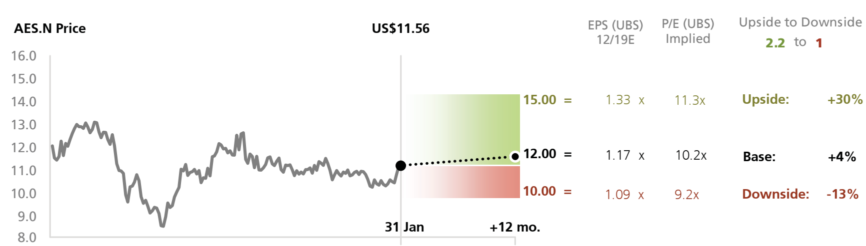
EVIDENCE

AES recently announced meaningful asset sales with sale of the Masinloc coal plant and development project for 14x Adjusted PTC ($1.05B) and is exiting the DPL merchant for $241M in cash. Recourse debt/parent free cash flow plus interest has declined from 6.4x in 2011 to our projected 4.8x in 2017. In terms of growth adders the Eagle Valley 671 MW combined cycle project in Indiana is 99% complete; OPGC II in India is on track for 2018 and Alto Maipo is 58% complete.

WHAT'S PRICED IN?

AES trades at a 5% discount to our sum of the parts. This reflects investor scepticism on Alto Maipo construction and delivering balance sheet targets.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	Alto Maipo 2019 EPS	Cost Cuts/ F/X	Unlisted Subs Proportional EV/EBITDA
$15 upside	$0.04	+$0.16	7.1x
$12 base	$0.04	$0.00	7.1x
$10 downside	$0.00	-$0.04	5.8x

Source: UBS

COMPANY DESCRIPTION

AES Corporation is an electric distribution and generation company in 16 countries that owns 7 utilities and 36 GW of thermal and renewable generation. The company's largest...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Is the regulatory environment in LNT's jurisdictions changing?

No, we do not see evidence of it. In Iowa the company is involved in two non-controversial proceedings related to 500 MW wind additions in 2019 and 2020 which are covered under Advanced Ratemaking Principles approved by the Iowa Utility Board. LNT reached a settlement related to the first plant, which includes a 10.0% ROE. LNT requested an 11.0% ROE for the second plant and requested a decision by January 31. The company expects to file a case in Wisconsin in Q2'18 and is allowed a reasonable 10.25% ROE before sharing mechanism takes effect.

Q: How long can LNT maintain 5-7% EPS growth?

At least through 2020, which is the duration of rate base guidance. We estimate 6% EPS growth from a normalized $1.88 in 2016 to $2.43 in 2020. Tax reform will likely provide LNT the ability to raise its cap-ex forecast when they roll-forward to 2022 likely this Fall. LNT's capital spending plan declines in 2020 when 1,200 MW of wind and the 730 MW West Riverside plant comes on-line in Wisconsin.

Q: What is the impact of tax reform?

On an EPS basis we see a small negative impact of 1-2 cents due to non-utility expenses. LNT's ownership in the ATC transmission company and in Sheboygan Falls are considered utility assets for tax so the lower rate has no impact. We expect LNT to continue issuing equity during the recently increased cap-ex spending period. We assume annual equity needs of $100-$200M annually.

UBS VIEW

LNT is well positioned to deliver 5-7% EPS growth with detailed growth drivers through 2020. The company operates in jurisdictions with predictable regulation in Iowa and Wisconsin. The stock has experienced some profit-taking this year (-2.4% versus the XLU), but still trades at a 13% premium to the Regulated Utility group on our '19E EPS and has a 3.4% dividend yield in line with the group.

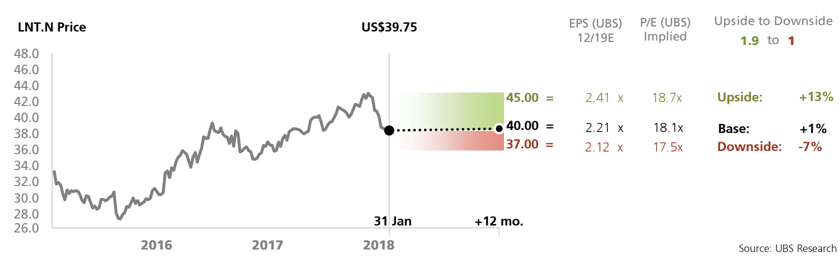
EVIDENCE

LNT has managed large project risk which supports the company's ability to execute on other projects. LNT completed the 660 MW Marshalltown gas plant in Iowa on time and under budget. The company is issuing equity to support its balance sheet.

WHAT'S PRICED IN?

LNT prices in a 2.68% 10-year treasury yield based on the group's valuation vs. the Moody's Baa bond (which is 91% correlated since 1980) and a constant spread to the 10-year treasury bond.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	P/E Premium 2019E EPS	Allowed ROE	UPO EPS Growth 2017-2022E
$45 upside	17%	11.0%/+$0.16	8.0%
$40 base	14%	10.0%	6.4%
$37 downside	10%	9.6%/-$0.06	5.7%

Source: UBS

COMPANY DESCRIPTION

Alliant Energy is a utility holding company that maintains its principal executive offices in Madison, Wisconsin. Alliant Energy's focus is to provide regulated electric and gas...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can the rate base grow faster than 6%?

We expect it will, but that depends on approval of the proposed investment in wind in Missouri. Our EPS estimates and consensus appear to incorporate approval of this project. The 700 MW project adds $0.25 to EPS and takes 5 year growth to 7.1% from 5.7%. Likewise it adds $1B to rate base taking 5 year growth to 6.7% from 5.6%. Necessary regulatory approvals should be complete in 1H'18.

Q: Will Missouri legislation improve the regulatory construct in 2018?

We rate Missouri as a bottom quartile regulator. Utilities in the state have difficulty earning their allowed returns due to regulatory lag. AEE has committed to an incremental $1B investment over 5 years and $4B over 10 years in modernized infrastructure if regulation improves. For the last several years, utility legislation has failed to pass despite bipartisan support. Another attempt is expected in 2018. There are two bills currently filed -- SB 564 and SB 572 -- and the session ends May 18.

Q: Do you expect AEE's returns to benefit materially from rising interest rates under Illinois formula rates?

Illinois allowed returns for electric distribution are a function of the 30 year treasury yield plus 580 bp. Each 50bp of higher T-Bond rates adds $0.04 per share to AEE earnings. Our estimates reflect no change in these rates.

UBS VIEW

With the stock trading at a 10% premium to our in-line 2019 EPS forecast, we do not find AEE attractive without an incremental investment opportunity. As our numbers already incorporate the Missouri wind proposal ($1B investment) pending regulatory approval, an improvement in Missouri Utility legislation is the potential source of upside. The Missouri legislative session is open through May. Given past failures, we view the chances of a Utility reform law in 2018 as highly uncertain.

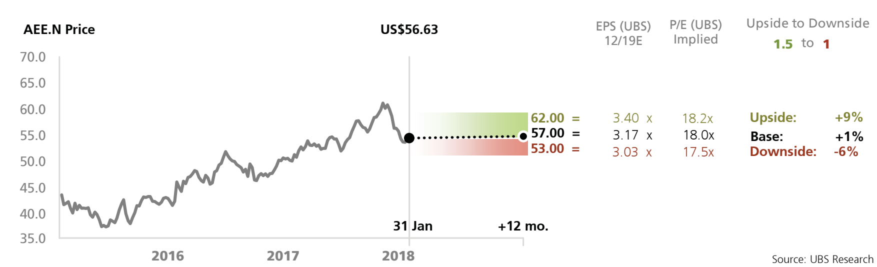
EVIDENCE

The stock is pricing in a start to the Missouri wind construction in 2019. We assume Missouri approval of AEE's wind proposal and a small benefit EPS benefit from tax reform. The wind investment adds $0.25 to EPS (7.1% 5 year growth) and $1B to rate base (6.7% 5 year growth).

WHAT'S PRICED IN?

AEE prices in a 2.72% 10 year treasury yield based on the group's valuation vs. the Moody's Baa bond (which is 91% correlated since 1980) and a constant spread to the 10 year treasury bond.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Rate base Growth	IL Formula ROE	EPS 2019E	P/E Premium/ discount 2019E
$62 upside	7.8%	9.25%	$3.40	13%
$57 base	6.7%	8.75%	$3.17	13%
$53 downside	5.6%	8.25%	$3.03	10%

Source: UBS

COMPANY DESCRIPTION

Ameren Corp. is the parent company of electric and gas utilities that serve Illinois and Missouri, with 2.4 million electric customers and 900,000 gas customers. Ameren Missouri is...

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PIVOTAL QUESTIONS

Q: Will Wind Catcher get through?

It is too close a call to include in our estimates or valuation. Oklahoma which represents 30% of the rate-base is the bigger concern than the SWEPCO territory (AR/LA/TX) and likely the gating approval for the project. AEP is working to settle and is offering guarantees on cost, performance, most favored nation treatment and PTC qualifications. The OK Attorney General has requested an RFP and the Administrative Law Judge (ALJ) recommended ROE in the current case was low at a 9.0% ROE. The outlook for Texas is better where a recent decision included a 9.6% ROE.

Q: Will Oklahoma continue to be challenging?

A near-term decision in AEP's Public Service Company of Oklahoma (PSO) rate case should provide an early indication of whether there has been improvement. A wait-and-see approach could be prudent as AEP stated that the proposed decision in the GRC would imply a 5% ROE for PSO, which is not acceptable. The Governor appointed a task force to review regulation, but legislation or elections could be required for significant change. For the Wind Catcher project AEP has made concessions to secure approval like cost caps and returns of excess off-system sales margins to customers.

Q: What are the implications of tax reform?

Tax reform should improve customer affordability for AEP customers and raise rate base growth over the long term through the absence of bonus depreciation. AEP plans to issue an incremental $400M of equity in 2020, but this is only 1-2 cents dilutive from the lag in reinvesting in utility growth.

UBS VIEW

We like AEP's 5-7% EPS and DPS growth excluding Wind Catcher, which could help exceed the growth rate near term and deliver 7% EPS growth over 5 years. Management has done a good job improving jurisdictional returns and allocating capital in the best places.

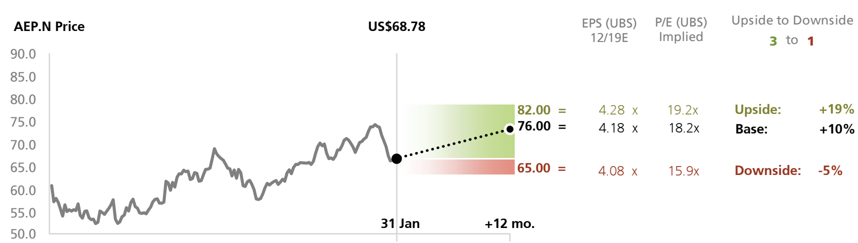
EVIDENCE

AEP has developed a track record for improving the utilities' performance and most recently earned a 9.5% ROE in the trailing 12 months. Rate cases at Kentucky Power which resulted in a largely adopted settlement and a 9.6% ROE at SWEPCO Texas should help meet or beat guidance.

WHAT'S PRICED IN?

We would argue none of Wind Catcher's $0.20-$0.25/share contribution or $3-$4/share value is priced in. The stock prices in a 3.16% 10-year treasury yield assuming a spread to the Baa corporate bond where the relationship has a 91% correlation since 1980.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	Wind Catcher or Not	Res/Comm +2% Sales	Cap-ex Spending -$1B	P/E 2019E Valuation
$82 upside	Yes-$4/NPV	+$0.10/share	0	+14%
$76 base	No	0	0	+14%
$65 downside	No	0	-$0.10/share	0%

Source: UBS

COMPANY DESCRIPTION

American Electric (AEP) is one of the largest electric utilities in the US, serving 5.4 million customers in 11 states in the Eastern region. The company owns approximately: 39,000...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Could tougher Michigan regulation take CMS off its 6-8% EPS growth path?

CMS reflects a reliable utility and a reasonable Michigan regulatory environment. CMS has been delivering 7% EPS growth since before 2008 and recently raised EPS growth guidance to 6-8% from 5-7%. CMS has significant leverage to capital spending increases and tax reform could provide headroom in customer rates for CMS to utilize for reinvestment in the system.

Q: What takes CMS beyond its $18B 10 year cap-ex plan?

CMS has identified upside scenarios of $21B and $25B over 10 years which Michigan needs with customer rates being the key constraint. We calculate a $3B change in spending is a 1.5% impact on the growth rate over 10 years. The first areas the company would target are gas infrastructure, grid modernization, renewables and reliability.

Q: What are the impacts of tax reform?

On an EPS basis, we estimate a -$0.02/share impact from lower tax deductibility on the corporate interest expense. Pre-tax income from Enerbank and CMS Enterprises (about $90M combined) help to offset the impact of $130M of interest allocated to the utilities. On 1/18 CMS filed with the Michigan Public Service Commission to flow a $172M rate reduction to utility customers from tax reform.

UBS VIEW

CMS reflects a reliable utility and a reasonable Michigan regulatory environment. CMS has been delivering 7% EPS growth since before 2008 and recently raised EPS growth guidance to 6-8% from 5-7%. CMS has significant leverage to capital spending increases and tax reform could provide headroom in customer rates for CMS to utilize for reinvestment in the system.

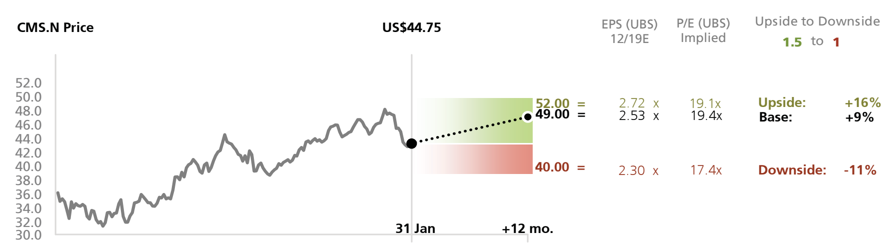
EVIDENCE

CMS rightly makes the case that Michigan needs significant infrastructure investment which drives their 10 year $18B plan and which could be upsized to $25B. Adjustments to the ALJ decision in the electric case for pension, sales forecast and rate of return should produce a final order more consistent with our forecast for $85M and a 10.1% ROE.

WHAT'S PRICED IN?

The stock prices in a 3.06% 10 year treasury yield assuming a spread to the Baa corporate bond where the relationship has a 91% correlation since 1980. CMS prices in 5.3% EPS growth using the 17% premium multiple we would view appropriate for second quartile growth.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	P/E Premium '19 EPS	Electric GRC EPS	Cap-ex Spending
$52 upside	20%	$0.00	+$1B/-$0.18
$49 base	20%	$0.00	$0.00
$40 downside	10%	-$0.06/ALJ	-$1B/-$0.18

Source: UBS

COMPANY DESCRIPTION

CMS Energy is the holding company of several utility and power businesses operating primarily in Michigan. The company owns Consumers Energy, which is a utility that provides...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will utility cap-ex at ED reach above-average rate base growth?

Cap-ex will not surprise unless ED wins a competitive transmission bid in the Northeast. ED is pursuing transmission projects in New England through Con Edison Transmission and $1B in an upstate New York project through 46% owned New York Transco. At CECONY, the company's 3 year rate plan largely sets rate base growth through 2019. There continues to be risk from the Reforming the Energy Vision program for its impact on investment levels and competition.

Q: Can CECONY surprise on earned returns versus the 9.5% ROE priced in?

Delivering on CECONY incentives could help ED's CECONY to earn a 9.5% financial ROE, but sharing mechanisms return most of the benefits above that level with customers. Incentives include spending on grid modernization and gas distribution. There is risk to recovering spending on the 2017 MTA outages which is not in tracked rates. Every 50 bp in ROE is worth $0.20/share so EPS is sensitive to a change.

Q: Will Con Edison Development become a more material contributor to growth?

New York has a positive policy overlay to infrastructure spending with targets including 40% CO2 reduction versus 1990 levels and 50% renewables by 2030. We do not expect a significant change from the Clean Energy Businesses' 8-10% projected EPS contribution versus 6.5-7.0% in 2016 and 2017.

UBS VIEW

We expect ED to continue to deliver on its plan to grow rate base at 5.5% at CECONY and to pursue non-utility expansions in the expanded Northeast. The MTA outages and Reforming the Energy Vision continue to present regulatory risk. ED has a neutral EPS impact from tax reform and utility customers could receive a related 2% reduction in bills.

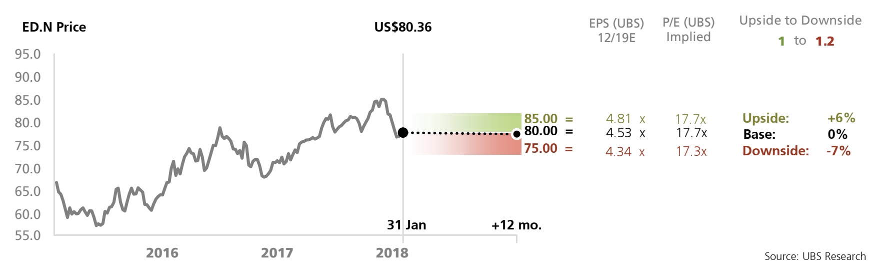
EVIDENCE

We looked at ED's earned returns over time, authorized rate structure and the likelihood of outperformance. CECONY earned a 9.2% ROE on average over 2015-2016, and the sharing mechanism applies most to earnings above a 9.5% ROE to regulatory assets.

WHAT'S PRICED IN?

The stock prices in 5 year EPS growth of 4% and a 10 year yield of 2.70% premised upon the group's under valuation vs. the Moody's Baa Yield (which is 91% correlated since '80) and a constant spread to the 10 year treasury.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Transmission Upside EPS	Earned ROE	CED +/- 200 MW '19E EPS
$85 upside	+$0.20	9.50%	+$0.08
$80 base	$0	9.50%	0
$75 downside	$0	9.25%	-$0.08

Source: UBS

COMPANY DESCRIPTION

Consolidated Edison's business segments are: Consolidated Edison Company of New York (CECONY), which provides regulated electric, gas, and steam service; Orange & Rockland, which...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will Dominion close the acquisition of SCANA?

We have a 50/50 view on deal close. Success is likely to hinge on D's political and regulatory negotiating prowess to garner support for its proposal. It may also be possible for D to sweeten the deal for SC ratepayers, while maintaining the economics for D shareholders.

Q: Should I worry that Cove Point has not begun commercial operation?

No. Dominion missed its year-end 2017 target for commercial operation and now expects the facility be in service in early March. The delay is disappointing considering that Cove Point seemed to hit all the appropriate milestones along the way to COD; however, this is a large engineering construction project and a few months of incremental delay to commercial operation does not give us cause for concern.

Q: Will HB1558 be good for Dominion?

Yes. The bill supports capital investment for 4,000 MW solar, 16 MW offshore wind, smart meters and undergrounding – areas where D has already identified approximately $11 billion potential investment over the next 12+ years. The bill would also eliminate the current base rate freeze and replace it with triennial reviews that would begin in 2021 for Virginia Electric Power Company (VEPCO).

UBS VIEW

Dominion's business profile is backstopped with a favourable regulatory landscape at VEPCO. Passage of HB1558 would further enhance VEPCO's regulatory construct and enhance capital investment opportunities. Cove Point is due online in 2018 providing a boost to cash flow and support for 10% annual dividend growth through 2020. Catalysts include HB1558 (Feb/Mar), Cove Point COD (Mar), and long shots - SCG merger and Millstone bidding in CT auction.

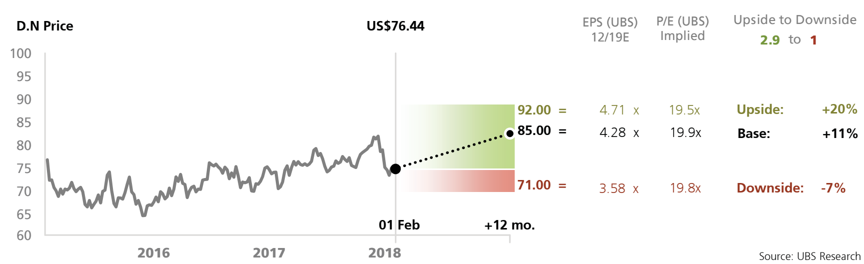
EVIDENCE

We rank VA in the top quartile of regulatory jurisdictions. VA has a history of passing constructive utility legislation supported by Dominion Energy. Regarding the SCG proposal, there is already vocal opposition by key SC policymakers to the transaction and D has expressed little room for negotiation.

WHAT'S PRICED IN?

The stock is pricing in risk related to the SCG merger and reflects uncertainty of when Cove Point will begin commercial operation. Positive news on those events should alleviate overhang on the stock. There is also further room for upside if HB1558 passes in VA or Millstone receives approval to bid into a state procurement. There is downside risk to the stock if Cove Point requires an extended delay beyond 1H18.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	SCG merger (50% impact)	Incremental Ratebase	Millstone Pricing	Cove Point Methodology
$92 upside	+$0.05	+$1B	$55/MWh	12.6x EV/EBITDA
$85 base			$41/MWh	20.0x P/E
$71 downside		-$1B	$35/MWh	20.0x P/E

Source: UBS

COMPANY DESCRIPTION

Dominion Energy is one of the largest energy producers and transporters in the US. The company is headquartered in Richmond, Virginia, with operations in 18 states. Assets include...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can DTE reinvest enough in the unregulated businesses to maintain its 5-7% EPS growth rate to 2022?

DTE will be in a good position if they can continue to invest at historical returns. We have conservatively assumed a 10% ROE on NEXUS, which the company expects to complete in Q3'18. We assume a 12% ROE on other new GSP and Power & Industrial investments.

Q: Can DTE's utility rate base growth and returns beat the industry?

Yes, we forecast above-average 5-year 5.5% EPS growth and 7.5% rate base growth. Drivers are investments in electric distribution and gas infrastructure. This compares to DTE's rate base growth guidance of 6-7% for electric and 7-8% for gas from 2017-2022E. We also assume no changes to top quartile regulation in Michigan. DTE Electric and DTE Gas are authorized a 10.1% allowed ROE compared to 9.7% for the industry.

Q: What is the impact from tax reform?

DTE benefits from a lower tax on its unregulated GS&P business and from higher rate base growth over time with the expiration of bonus depreciation. Overall we see a small positive impact from an EPS standpoint, and DTE plans to return $186M to utility customers or a 3% rate reduction.

UBS VIEW

DTE stock is a core holding that has significant and diverse investment opportunities. We expect above-average utility EPS growth in a top jurisdiction. On the unregulated side the NEXUS project is under construction and on track to complete in Q3'18 and the company is in discussions on co-gen and CNG projects. The company offers high single- to double-digit total return with 5-7% EPS and 9% DPS growth.

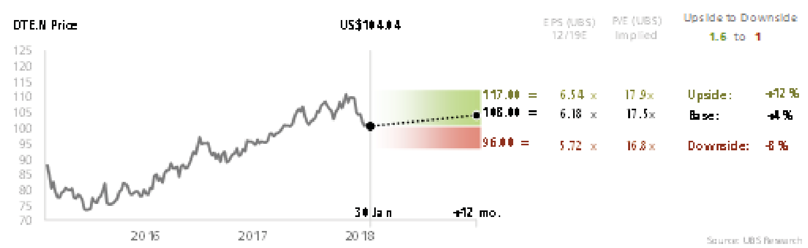
EVIDENCE

The DTE Electric investment plan is focused on distribution infrastructure and totals $10.4B through 2022. Over 2013-2017 DTE's investments in the GSP business grew net income $90M. We expect DTE can grow consolidated EPS 6.5% comparable to DTE's 5-7% EPS guidance using 12% ROEs on unregulated investments.

WHAT'S PRICED IN?

DTE stock price reflects a $0.25/share reduction in unregulated EPS or 5% utility EPS growth.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	P/E Premum '19E EPS	Ratebase Growth '17-'19E	Unregulated ROE on Investment
$117 upside	+20%	9.3%	12.0%
$108 base	+17%	6.3%	12.0%
$96 downside	+13%	3.3%	11.0%

Source: UBS

COMPANY DESCRIPTION

DTE Energy is a Detroit-based company with regulated utilities that include DTE Electric, which serves 2.2m customers in Southeastern Michigan, and DTE Gas, which serves 1.3m...

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UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will DUK receive recovery of coal ash in North Carolina?

We believe the highest likelihood outcome is that DUK receives recovery of its coal ash expenditures with a debt-return. Our confidence in grounded in the legislative mandate directing coal ash clean-up, as well as the commission's historically constructive ratemaking treatment. In our view, clarity on coal ash will act as a catalyst for the shares. The North Carolina Public Utilities Commission is expected to issue a decision in DEP's rate case by March 1. Also, we could see a settlement in DEC's rate case prior to the start of hearings February 19.

more→

Q: Will DUK be able to realize the full extent of its $49B capital expenditures forecast?

Regulatory outcomes and bill affordability will be the gating items to incremental investment; however, going in DUK's favour is rate headroom created by the lower corporate tax rate, O&M savings as coal plants retire, and a potential increase in economic development in the Southeast U.S.

more→

UBS VIEW

DUK shares reflect an attractive risk-reward with overhang of the coal ash recovery issue expected to clarify in 1Q18. The valuation presents an unusual opportunity to accumulate DUK shares as a long-term core holding. As a large cap regulated electric and gas utility with a 1st quartile regulatory ranking, a premium multiple is justified. DUK shares offer a 4.6% dividend yield. The shares seem to reflect loss of equity and debt return on coal ash and possibly even disallowance of some of the expenditures.

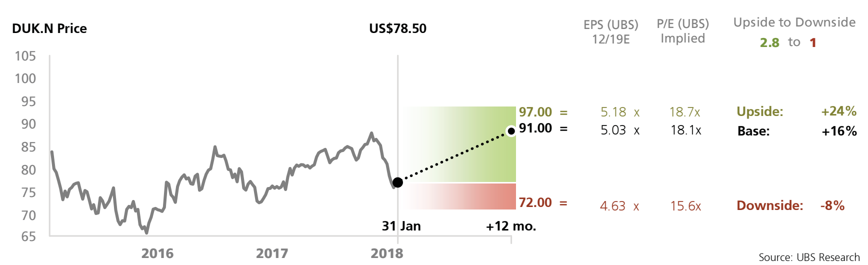
EVIDENCE

DUK's coal ash spending is in line with state required clean-up activities. DUK reached a constructive settlement at DEP on all issues with the exception of coal ash and deferred storm recovery, which remain outstanding. Our analysis ranks NC as a top tier regulatory jurisdiction on the basis of allowed ROEs, settled vs. litigated cases, appointed vs. elected commissions, and overall constructive outcomes.

WHAT'S PRICED IN?

DUK's price is not reflective of a large cap 4-6% growth regulated utility with a 1st quartile regulatory ranking. Constructive outcomes to the two NC rate cases in 1H18 should remove an overhang and allow the stock to re-rate to match its premium Southeast peer group. Translated to bond pricing, we calculate DUK discounts a 3.38% 10-year T-Note yield.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Total Capex	Coal Ash Return	'19E P/E Premium/ discount
$97 upside		$0.15	17.0%
$91 base	$48.9B	$0.05	13.0%
$72 downside	$43.5B	($0.05)	-3.0%

Source: UBS

more→

COMPANY DESCRIPTION

Duke Energy operates a vast network of regulated electric utility and natural gas distribution assets in seven states in the Southeast and Midwest US, serving approximately 7.4...

more →

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: When will we have regulatory clarity on and how can assess EIX' wildfire liability?

Cal Fire is leading the investigation of the 2017 Northern California wildfires. The process could take up to 18 months and would conclude with a determination of root cause and potential responsible parties. Under California inverse condemnation law, the utility is liable if found to be responsible, but can request recovery based on a prudency determination. SRE was denied $379M recovery related to 3 wildfires in late 2007 (Case A1509010) which has sparked a sharp discount in EIX shares given the massive scale of the '17 event. We estimate the range of potential net liabilities to be $0 to $7B if EIX is found responsible for the Thomas wildfires.

more→

Q: How does EIX' rate base growth compare to the industry and what risk does the GRC pose?

EIX 5 year rate base growth of 8.0% is above average and is supported by climate goals in California. We see upside to growth from EV and other infrastructure spending, but it is dependent on regulation returning to normal. In the GRC we see -$0.08/share of '19 EPS exposure to ORA's position but +$0.23/share of upside to the company's proposal from our estimates. We don't believe the San Onofre nuclear outage proceeding will materially change the story.

more→

UBS VIEW

It is too soon to buy the stock as the fire claims responsibility and prudency are yet to be determined. We estimate the range of outcomes is from no liability (34% upside to the stock) to $7B in liability (17% of further potential downside). There is limited downside to the ORA position in the GRC from our estimates and no precedent for a worse outcome.

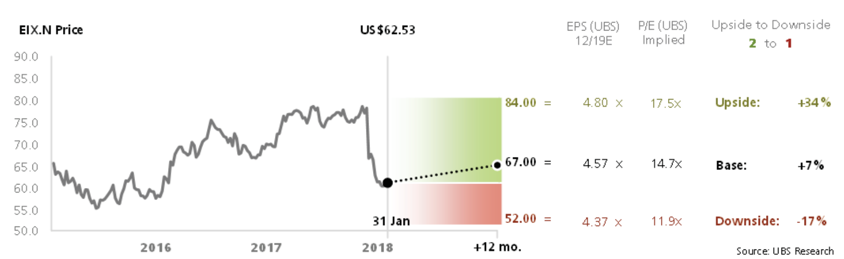
EVIDENCE

SRE was denied recovery of $379M of wildfire inverse condemnation liabilities based on a CPUC prudence determination on 11/30/17. The Northern California wildfire currently has claims of $9.4B. The Thomas fire is likely significantly less but claims are not yet compiled.

WHAT'S PRICED IN?

We calculate $6.0-$7.1B in net wildfire damages (up to $22/share) is in the stock. Ex the fire EIX could be worth $84 at a 10% premium multiple to the Regulated Utility group applied to $4.80 in 2019.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Net Wildfire liability	EPS Cost to fund liability	Rate Case Outcome	Premium/ Discount '19 P/E
$84 upside	$0	$0	+$0.23/share	10%
$67 base	$3.2B	$0.66	--	-8%
$52 downside	$7.1B	$1.47	-$0.20/share	-26%

Source: UBS

COMPANY DESCRIPTION

Edison International is the parent company of Southern California Edison, which is an electric utility serving Central and Southern California with 5 million residential and...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can ETR successfully shift out of merchant nuclear generation and back to a pure regulated utility?

Yes. Exiting EWC is coordinated with contract expirations and negotiated agreements. Execution of this strategy between now and 2022 should materially reduce ETR's nuclear operational risk, as well as potentially reduce ongoing decommissioning risk (if sales are successful). EWC is expected to be cash flow breakeven over the exit period. Recent regulatory orders also illustrate an improving regulatory profile. ETR's regulatory outlook is further enhanced by a capital budget aimed at upgrading an aging generation fleet and installing AMI technology.

Q: Can ETR's regulatory conditions allow for above average growth?

ETR is moving in the right direction, but not all the way there yet. ETR can continue to reduce regulatory lag with ongoing implementation of formula rate plans in AR, LA and MS. Arkansas took a giant step in the right direction when supportive legislation was passed in 2015 allowing formula rate plans. Three successive settlements in AR have further bolstered investor confidence. Relations in LA and MS are generally constructive. TX remains a challenging jurisdiction with regulatory lag.

UBS VIEW

We value ETR based upon UPO earnings only. This reflects ETR's strategy to exit merchant nuclear generation by YE22, as well as avoids the valuation challenge presented by the declining earnings profile of EWC. ETR is demonstrating some success in improving regulated operations and earned returns, but has farther to go in this regard. Also, ETR is making progress on reducing the exposure of its merchant fleet. Sale of the Vermont Yankee plant would demonstrate the opportunity for meaningful risk reduction going forward. Further improvements in operations and earned returns will support a higher premium in the future. Conversely, investors will lose confidence in the face of poor nuclear operations (on the regulated or unregulated side of the business) or declining earned returns.

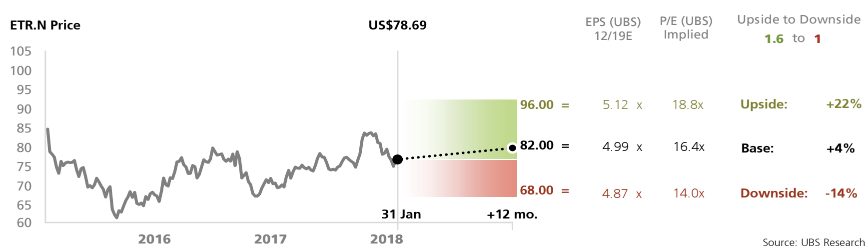
EVIDENCE

ETR has demonstrated its ability to execute on its exit strategy by selling one merchant plant and retiring another plant. The remaining facilities are scheduled to retire from 2019-2022. ETR's regulatory relationship in Arkansas is much improved in the past three years.

WHAT'S PRICED IN?

Consensus estimates reflect a combination of UPO and Consolidated estimates, rendering the consensus mean irrelevant and misleading. ETR is trading at a 1.4% P/E discount based on 2019e UPO earnings, in our view, accurately reflecting the ongoing risk profile of ETR. Translated to bond yields, we calculate ETR is discounting a 2.97% 10-year T-Note yield.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Ratebase	Premium	EPS growth	Regulatory Ranking
$96 upside	30.0B	17%	1st quartile	2nd quartile
$82 base	25.5B	3%	1st quartile	3rd quartile
$68 downside	20.0B	-13%	2nd quartile	4th quartile

Source: UBS

COMPANY DESCRIPTION

Entergy Corporation is a holding company with regulated electric utility subsidiaries in Arkansas, Louisiana, Mississippi, and Texas. ETR also owns a portfolio of unregulated...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Is Northern Pass likely to be approved and meet investor expectations?

Yes, in our opinion, NPT is likely to be approved; however, project cost and timing expectations may need to be revised. The SEC is scheduled to issue a decision in late-February. Based on our analysis which includes attending several of the 70 public hearings that took place in 2017, and knowing that NH Governor Sununu supports the project, we expect NPT to be approved. While approval would be a notable, positive data point, we caution investors that there could be conditions to the permit approval, such as additional undergrounding, that could impact the cost and/or timing of the project.

Q: Does a pure T&D utility warrant a premium valuation?

We think it does. The asset mix of a pure transmission and distribution utility is lower risk than for companies with fossil generation assets. The industry is on a path to reduce carbon exposure and pure T&D companies have already achieved this objective. Finally, T&D companies unencumbered by generation are more likely to meet the threshold of the growing class of ESG investors.

UBS VIEW

We view ES' premium as appropriate, in light of the lower risk pure T&D business mix and above-average 5-7% EPS CAGR. The near-term risk to estimates and valuation that concerns us relates to the proposed Northern Pass Transmission project. Our estimates rely on NPT contributing approximately half of ES' earnings growth through 2020. We estimate the company could backfill roughly half of that if the project doesn't come to fruition.

EVIDENCE

Valuation multiples of gas and water distribution companies are consistently higher than for integrated electric companies. T&D assets are treated as lower risk than generation. Our proprietary research includes having attended several of NPT's public hearings that took place in 2017.

WHAT'S PRICED IN?

At the current price, ES is pricing nearly 100% likelihood that NPT will proceed to construction. We estimate approximately 5% downside risk if the NPT site permit is completely denied, and some share price exposure if material changes are made to price or timing. Translated to bond pricing, we calculate ES discounts a 3.03% 10-year T-Note yield.

UPSIDE / DOWNSIDE SPECTRUM

Value drivers	Incremental Capex	'19 P/E Premium/ discount
$70 upside	$800MM	21.0%
$66 base		18.0%
$56 downside	($800MM)	3.0%

Source: UBS

COMPANY DESCRIPTION

Eversource Energy is the only vertically-integrated electric, natural gas, and water distribution and transmission company in the US. ES entered the water distribution business...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can management continue to deliver improving returns at the Pepco Utilities?

Yes, through improved customer service at Pepco and successful rate cases, EXC can close the earned to allowed ROE gap to 36bps in 2020 from 247bp at end 3Q17. Improved ROE drives roughly half the utility growth we forecast of 6% - 8% through 2020.

Q: Will PJM Market Reform and NJ Legislation Deliver Upside to Power Markets?

Potentially. FERC has requested proposals from system operators by March 9. We also see zero emission credit (ZEC) like payments developing in New Jersey via legislation in 1H 2018. Neither of these proposals are in our base case and could add up to $0.35 in eps vs our estimates in 2019 and 2020.

Q: Will Investors Begin to Revalue Exelon now that Dividend Policy has Changed?

Yes. We expect progress integrating Pepco, an improved balance sheet and ZEC legislation in NY and IL should allow management and the board to raise the dividend growth rate to 5% through 2020 consistent with peer guidance of 4% - 6%.

UBS VIEW

We see shares undervalued with upside catalysts coming from the dividend strategy update on 1/30. The Utility Segment will show upside from continued closure of the Pepco allowed to earned ROE gap and an additional $1.6Bln in rate base by 2020 from tax reform. ExGen will have valuation upside over time from deleveraging, potential PJM market reform, and nuclear support programs in New Jersey.

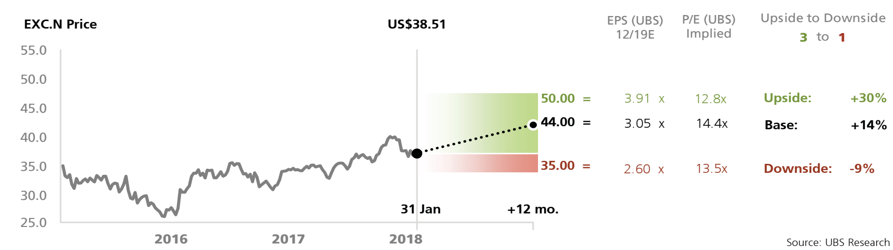
EVIDENCE

Management improved the ROE gap at BGE from -568bps in 2012 to +89bps in three years post purchase. EXC has now started on a similar path at the Pepco utilities, closing the gap by 98bp from March 2016. PJM estimates 2% - 5% uplift to energy markets from its reform proposals. NJ Governor Phil Murphy indicated he wants the nuclear industry in the state to be viable post his election win in November.

WHAT'S PRICED IN?

At the current price of $38.05/share, the stock prices in either: 1) A RU business at an 8% discount to peers expecting a failure to deliver on the integration of the Pepco Holding merger; or 2) ExGen is trading at 4.75 EBITDA or ~$4/share.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	NJ ZEC ExGen Margins	UPO Valuation Premium	Regulated CapEx	+/-$2.50/MWh ExGen Margins	Rate Case Recovery
$50 upside	+$125mln	13.0%	+5%	+$400mln	$396mln
$44 base	$0mln	13.0%	0%	$0mln	$396mln
$35 downside	$0mln	0.0%	-5%	-$400mln	$150mln

Source: UBS

COMPANY DESCRIPTION

Exelon owns six regulated utility subsidiaries: Atlantic City Electric, BGE, ComEd, Delmarva Power, PECO and the Pepco Subsidiaries which deliver electricity and natural gas to...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will an exit of merchant subsidiary FES stabilize the credit profile and help the stock?

Exiting FES will shed the company of liabilities and allow investors to focus on the premium Regulated Utility. In the process we expect CFO/debt improves by at least 1.1% without requiring additional equity. Our downside scenario of a substantive consolidation is 7% lower and includes $2.9B of liabilities and $0.4B of equity to maintain investment grade. The upside scenario to $41 (+25%) includes $1B of additional capital spending, which adds $0.09/share.

Q: How does the FE Regulated Utility compare to its peers?

From a rate base growth perspective, the Regulated Utility is above average at 7.3% growth from 2016 to 2019. FE's guidance for distribution rate base growth is 4% from 2016 to 2019 and 9% for transmission from 2016 to 2021. The places where there are most likely incremental opportunities are in Ohio and New Jersey. Our upside scenario assumes $1B of additional cap-ex in '19, which would yield 8.9% rate base growth, or the high end of peers. We assume an incremental $0.5B in Ohio and $0.5B in New Jersey.

UBS VIEW

With the exit of merchant subsidiary FES by 2018, the focus will shift to FE's utility, which is a catalyst for performance. The utility has above-average growth metrics and FE is developing a track record for hitting their goals under CEO Chuck Jones. The risk is failure to settle with FES creditors, leading to a long bankruptcy workout and risk of incremental financial exposure to FE.

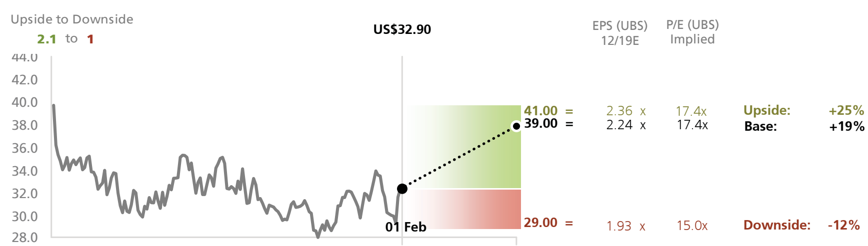
EVIDENCE

On 1/22 FE took a more aggressive approach to becoming fully regulated by issuing $2.5B of equity and preferred securities and forming a working group of FE executives and recent investors (including Mr. Wilder) to negotiate the FES bankruptcy. Moody's responded by lowering FES to Ca and raising the probability of default rating. FES has a $99M maturity due on April 2, 2018, which will likely trigger reorganization.

WHAT'S PRICED IN?

FE stock price reflects an assumption of $2.2B in liabilities from FES, which does not require equity in order to maintain 12.0% CFO/debt and investment grade. This represents a 60% recovery of FES unsecured debt vs. 47% in the market and our estimated recovery of 29% without further obligation from FE.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	T&D Cap-ex '16-'19E	Utility Premium/ Discount '19E P/E	FES Liability $MM	Addtl Equity Required
$41 upside	+$1.0B	+7%	$0.9B	$0
$39 base	0	+7%	$0.9B	$0
$29 downside	0	-5%	$2.9B	$0.4B

Source: UBS

COMPANY DESCRIPTION

FirstEnergy Corp. is primarily a regulated electric utility serving 6 million distribution customers in the Midwest and Mid-Atlantic and a transmission system covering 24,000 miles...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will the merger with WR close and what are the financial implications?

Yes, we think the merger is likely to close in June following final approval from the Kansas Corporation Commission June 6 decision deadline. The all stock deal addresses the KCC's concerns over leverage and has received shareholder approval. We estimate small merger accretion in year 1 and 10% by year 3 (2021) using 70-80% of synergies retained for shareholders. Shareholders participate in a 22% stock buyback over the first 2 years.

Q: Are GXP's metrics above-average as a standalone company?

No. We estimate 5 year EPS growth of 1% for GXP versus 3.5% for the merged company. GXP has a greater share of Missouri as a standalone company at 60% versus 31% merged. The average regulatory ranking standalone is 28 versus 26 merged. Standalone GXP has $1.25B of excess cash to deploy which the company would likely use to repurchase stock .

Q: What are the implications of tax reform?

Cash flow could impact FFO/debt ratios although the combined company is solidly investment grade with FFO/debt in the high teens (18-20%). Tax reform is a -$0.02 to -$0.03/share EPS impact by 2021 and could push the FFO/debt to the lower half of the range..

UBS VIEW

We expect the revised merger to close and provide benefits for shareholders and for customers. The stock is close fair value in the short-term but we see 7% downside to not closing. The transaction provides EPS accretion, a better regulatory rank and participation in a 22% stock buyback.

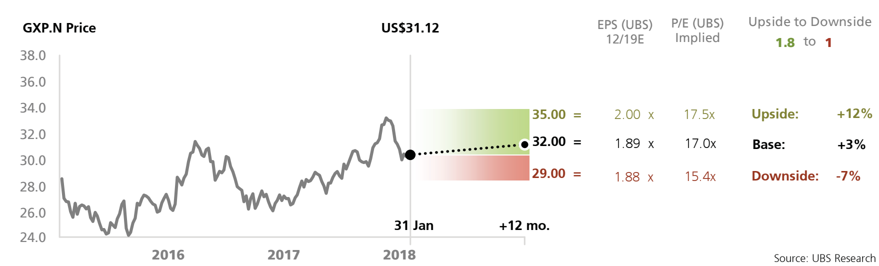
EVIDENCE

The company provided more detail on the merger synergies in Steve Brusser's testimony from docket CPE-095-MER. The companies target 15% cost reductions which supports the growth goals. We assume 70-80% retention of synergies and $1.25B of GXP's cash to help fund the buyback.

WHAT'S PRICED IN?

GXP stock prices in a 10 year yield of 2.74% premised upon the group's under valuation vs. the Moody's Baa Bond Yield (which is 91% correlated since 1980) and a constant spread to the 10 year treasury bond. Our downside scenario implies a 2.88% yield. The stocks do not appear to be pricing in a material likelihood of a break as the spread at 0.5981x is 1.8%.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Merger Outcome	Merger Synergies	Break Fee	P/E Premium/ Discount
$35 upside	Closes	$144M	N/A	+8%
$32 base	Closes	$88M	N/A	+5%
$29 downside	Breaks	$0	$190M	+0%

Source: UBS

COMPANY DESCRIPTION

Great Plains Energy Incorporated owns Kansas City Power & Light and Greater Missouri Operations Company. Combined, they serve 864,000 customers and own 6,524 MW of generation in...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can HE be acquired?

No. It is our assertion that any potential acquisition of HE has very low odds of success, as evidenced by the public outcry, political reaction, and ultimate commission rejection of NextEra Energy's efforts to acquire HE. HE is the largest publicly-traded company headquartered in Hawaii. That factor combined with a strong sense of regional identity makes any outside overture difficult. Further, in the rejection of the NEE/HE transaction, the commission provided guidance on six key elements necessary to meet the public interest standard in any future change of control application.

Q: Can ASB's value justify HE's share price?

No. Fairly valuing HE's utility operations at $19 per share ($1.21 2019e EPS, 16.0x Regulated Utility average P/E, 50% allocation of holdco losses), implies HE's share price incorporates approximately $15 value at ASB. Based on our $0.70 EPS in 2019e (including $0.14 tax reform benefit and 50% allocation of holdco losses), a value of $15 at ASB requires a 21.4x P/E multiple, or a 50% premium to ASB's peer group. That premium would put ASB among the top five highly-valued companies in the group of 61 peers, a valuation that is difficult to justify on ASB's fundamentals.

Q: Can HE reduce regulatory lag at the utility?

Yes, but we expect HE to consistently under-earn its allowed return. Utility rate increases should help narrow the ROE gap in 2018; however, systemic ratemaking issues in Hawaii are likely to prevent the utility from fully earning its allowed return. The three-year ratemaking schedule at the utilities maintains a regular lag and catch up cycle.

UBS VIEW

HE's rate base growth is constrained by bill affordability and a challenging regulatory commission, resulting in 3rd quartile utility earnings growth. ASB is not a large enough share of the company to justify HE's premium multiple. We do not see consolidation as a viable option for HE.

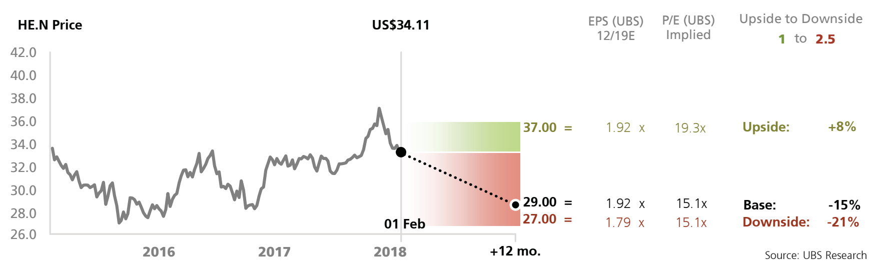
EVIDENCE

The NEE/HE consolidation attempt made clear that there is little public support for an acquisition of HE. The PUC merger guidelines establish a challenging threshold for future transactions.

WHAT'S PRICED IN?

We don't think the 12% premium cannot be justified on fundamentals alone. Assuming the stock incorporates fair value for the Utility and Bank earnings, the excess premium of 15% implies a 58% likelihood of acquisition potential based on historical trailing P/E merger multiples.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Bank Premium	Ratebase	Acquisition Multiple (trailing P/E)
$37 upside	10%		23.3x
$29 base	0%	$3.46B	
$27 downside	-10%	$3.21B	

Source: UBS

COMPANY DESCRIPTION

Hawaiian Electric Industries' two principal subsidiaries are engaged in electric utility and banking businesses. Hawaiian Electric is a regulated electric utility serving 95% of...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Does NEE need to do a deal?

No. NEE has sufficient credit metric flexibility that it does not need to make an acquisition; We expect NEE to continue to pursue opportunistic M&A. NEE's FFO/debt of 27% is well within S&P's FFO/debt threshold of 23%. Moody's has also indicated that it will reduce NEE's pre-working capital CFO/debt target to 18% from 20% if regulated operations contribute 70% of the business mix. NEE has approximately $5-7B of excess balance sheet capacity to utilize if the company were to pursue an acquisition.

Q: Will renewable growth for NEE peak in 2020?

State and corporate environmental mandates are likely to continue to support renewable growth beyond 2020 despite the decline in the production tax credit that is scheduled to take effect for projects that come into service in 2021 and beyond. Furthermore, cost efficiencies of renewables are closing the price gap that tax credits have historically filled.

Q: Will NEE be able to expand NEER's business profile?

We think NEER's industry leadership provides a unique platform for growth. Incremental investment in gas pipelines and battery storage present the greatest opportunities.

UBS VIEW

NEE offer investors exposure to a large cap regulated utility (57% of 2019E EPS) in a top quartile regulatory jurisdiction combined with the largest renewables business (43% of 2019E EPS) in the U.S. Above-average earnings and dividend growth is supported by a four-year rate settlement delivering highly visible and predictable earnings at the regulated business (+6% EPS growth) and a deep backlog of renewable projects in the development pipeline (15% EPS growth).

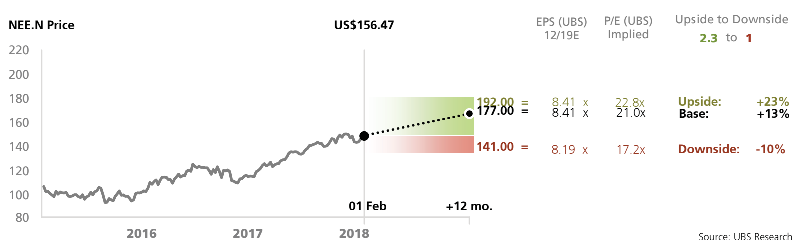
EVIDENCE

NEE has a four-year rate settlement that delivers a predictable regulated earnings stream. The renewables business benefits from economies of scale, which NEE capitalizes on as the largest renewables developer in the U.S. NEE has demonstrated strict discipline in its previous attempts at utility acquisitions. NEE has $5-7B of excess balance sheet capacity to utilize for growth opportunities.

WHAT'S PRICED IN?

The stock price reflects NEE's position as a core holding among regulated utility investments. We think the earnings re-base from tax reform (+$0.45) may not be fully reflected in the current stock price. The stock also likely incorporates some risk that NEE will continue to pursue a regulated acquisition.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	FPL/Corp P/E Premium	NEER Multiple	Ratebase	NEP value
$192 upside	20%	10x EBITDA	$46B	$9/shr M2M
$177 base	20%	30% P/E premium	$46B	$9/shr M2M
$141 downside	4%	4% P/E premium	$44B	$5/shr

Source: UBS

COMPANY DESCRIPTION

NextEra Energy is a leading clean energy provider with approximately 46,000 megawatts of generating capacity, composed principally of renewable, emission-free nuclear, and...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can OGE provide an upside surprise to rate base growth?

We expect OGE can, but it will have to be met with reasonable regulation. OGE has been spending on transitioning the generation fleet to gas and on environmental projects. We could see more spending on grid modernization and reliability, and we expect a plan from management on the Q4'17 call on February 22. For now, we model 4% rate base growth from '16 to '19 and 1% from '17 to '22.

Q: Are initiatives to improve regulation in Oklahoma likely to surprise investors?

Improvements in Oklahoma regulation will take time. A task force is working on recommendations to the legislature by November 2018. Expanding the Commission to 5 members from 3 would allow more collaboration by Commissioners and could occur. We assume OGE maintains its 9.5% allowed ROE in the current case, which is $0.05/share below the company's 9.9% request.

Q: What is the impact of tax reform?

OGE primarily benefits from the lower tax rate applied to the ENBL investment, which adds $0.08/share and $0.11/share to cash flow including the impact on the basis amortization. In the Oklahoma rate filing, the company identified a $68M rate reduction for tax.

UBS VIEW

We don't believe Oklahoma regulation is constructive enough for OGE to significantly increase spending. More likely the company will continue to grow the dividend at a high single-digit rate with its cash flow while they wait for improvements. An incremental 2% in rate base growth would require an investment the magnitude of OGE's request in the next 2 rate cases combined, which is too much to expect. OGE offers 10% dividend growth and a current yield of 3.4% while investors wait for the outlook to improve.

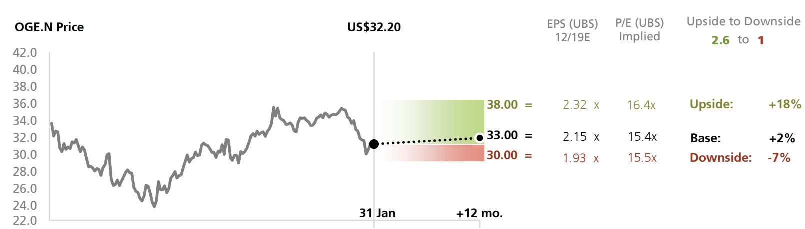
EVIDENCE

OGE's two Oklahoma cases request almost $1B of investment recovery, and every $400M change is a 1% difference in rate base growth. Tax reform helped to offset the initial impact on customers, but the ongoing impact for the two cases could require a high single-digit rate increase. The cap-ex investment required for a 2% change in rate base growth could pressures and OGE to cut expenses.

WHAT'S PRICED IN?

Excluding ENBL, OGE utility net of parent trades at a 5% discount to the 2019E Regulated Utility average (15.2x versus 16.0x). The discount valuation relates to the unpredictable Oklahoma regulatory environment and its limitations on growth.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	UPO 5-Year EPS growth '17-22E	Retail sales growth	'19E P/E Premium/ discount
$38 upside	4.8%	2%	3%
$33 base	2.2%	1%	0%
$30 downside	-0.8%	0%	0%

Source: UBS

COMPANY DESCRIPTION

OGE Energy is a holding company for Oklahoma Gas & Electric (OG&E) and OGE Energy Holdings which includes the company's 26% ownership in Enable Midstream Partners, LP. OG&E is a...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: When will we have regulatory clarity on and how can we assess PCG's wildfire liability?

CAL FIRE is leading the investigation of the 2017 Northern California wildfires. The process could take up to 18 months and would conclude with a determination of root cause and potential responsible parties. Under California inverse condemnation law, the utility is liable if found to be responsible, but can request recovery based on a prudency determination. SRE was denied $379M recovery related to 3 wildfires in late 2007 (Case A1509010) which has sparked a sharp discount in PCG shares given the massive scale of the '17 event. We estimate the range of potential net liabilities to be $0 to $16.1B if PCG is found responsible.

more→

Q: How does PCG's rate base growth compare to the industry?

PCG's 6.5-7% rate base growth is above-average and is supported by climate goals in California. On a 5 year basis we model 6% which is above average. We see upside to growth from EV and other infrastructure spending, but it is dependent on regulation returning to normal. Near-term the California Public Utility Commission's safety culture review where a ruling is due Q2'18 is important but PCG has addressed 63 of 68 issues. The Gas Transmission & Storage case and the 2017 transmission case are other proceedings to monitor.

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UBS VIEW

It is too soon to buy the stock as the fire claims responsibility and prudency are yet to be determined. We estimate the range of outcomes is from no liability (61% upside to the stock) to $16B in liability (37% of further potential downside and solvency concerns).

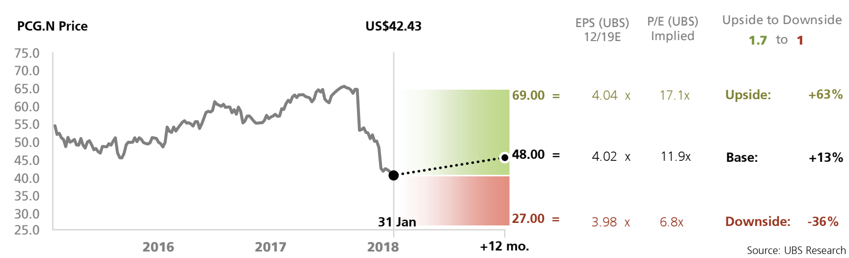
EVIDENCE

SRE was denied recovery of $379M of wildfire inverse condemnation liabilities based on a CPUC prudence determination on 11/30/17. The 2017 Northern California wildfire currently has claims of $9.4B.

WHAT'S PRICED IN?

We calculate $12.9B in net wildfire damages ($25/share) is in the stock. Ex the fire, PCG could be worth $69 at a 6% premium multiple to the Regulated Utility group applied to $4.04 in 2019.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	Net Wildfire liability $B	EPS cost to fund liability	Valuation Discount '19 P/E
$69 upside	$0	$0	6%
$48 base	$8.0B	-$1.25	-25%
$27 downside	$16.1B	-$2.52	-57%

Source: UBS

more→

COMPANY DESCRIPTION

PG&E Corp. is the parent company of Pacific Gas & Electric, which is an electric and gas utility serving Northern California and Central California including San Francisco. The...

more →

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: What trends are affecting sales growth and what is the impact?

Every 1% change in retail sales is an $0.08/share EPS impact. We assume 1.5-2.0% sales growth beginning in 2018 supported by accelerating customer growth of 1.3% for 2014-2016, 1.5-2.5% for a nation leading 2017 and 2.0-3.0% projected for 2017-2019. Arizona's growth fundamentals remain intact including a growing population, job growth and economic development. APS' Maricopa County was ranked #1 in the U.S. for population growth in 2016. Job growth in key areas is above-average. Construction and vacancy rates are at pre-recessionary levels. These things impact demand side management and resource planning proceedings.

more→

Q: What is the impact of tax reform?

We see a -$0.04/share EPS impact on PNW from the impact of a lower tax rate at the holding company level. PNW sees minimal cash tax payments through 2019 due to existing tax carry-forwards of $100M as of September 30, 2017. At APS we forecast that the deferred tax liability write-off could result in a 3.5% rate reduction for customers.

UBS VIEW

We are Neutral on PNW. The Arizona economy continues to support our outlook for PNW and we do not assume a new generation investment for now although this could be necessary over the next few years. If PNW adds a resource we would expect it to be gas combustion turbines to help manage reliability. We believe PNW is a premium company for its total return and as a placeholder for M&A. However, that is currently reflected in the stock's 6% premium value using 2019 EPS consensus.

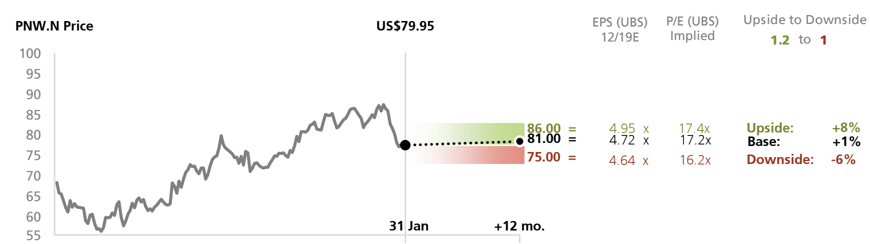
EVIDENCE

PNW's 6-7% rate base growth from 2015-2019 and no need for new equity supports 6% ongoing EPS growth. Sales growth and customer growth have been accelerating and are drivers as well. Weather normalized annual sales growth rose 0-0.2% from 2014-2016, 0-1.0% for 2017E and 0.5-1.5% for 2018E and we forecast 1.5-2.0% annually over the next 5 years supported by customer growth and the economy. PNW's April 2017 integrated resource plan does not include plans for a new investment at least through 2019.

WHAT'S PRICED IN?

The stock prices in a 10 year yield of 2.65% premised upon the group's under valuation vs. the Moody's Baa Bond Yield (which is 91% correlated since 1980) and a constant spread to the 10 year treasury bond. PNW trades at a 6% premium on our 2019 EPS estimate and consensus.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	Premium/ Discount '19 P/E	Sales Growth +/-2%	Generation/ Investment
$86 upside	7%	+$0.16share	$0.15/share
$81 base	7%	0	--
$75 downside	3%	-$0.16/share	--

Source: UBS

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COMPANY DESCRIPTION

Pinnacle West Capital Corporation is an electric utility holding company based in Phoenix, Arizona. Pinnacle West subsidiary Arizona Public Service is a regulated electric utility...

more →

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Is a Small Cap premium in utilities justified?

Is a small cap premium in utilities justifiable? Maybe, but PNM is expensive even with it applied. As a result of steady industry consolidation, the investible regulated utility group has shrunk from 98 issuers in 1995 to 44 at 12/31/16. Companies with less than $10B in market capitalization trade at an average premium of 8%. Even applying this to our valuation methodology for PNM leaves the stock overvalued.

Q: Is New Mexico regulation improving to support consistent growth?

Yes, but the pace of improvement is slow with backslides along the way. We expect this same trajectory of fits-and-starts to continue, thereby persistently maintaining a cloud of uncertainty over PNM's growth potential. PNM received mixed results in its last two rate cases before the New Mexico Public Regulation Commission (PRC). Most recently, the commission (somewhat reluctantly in a 3-2 vote) approved most aspects of a nearly-all party settlement in PNM's general rate case, but not without also incorporating a punitive factor in the final order. As a result, NM regulation remains unpredictable and subject to uncertainty.

UBS VIEW

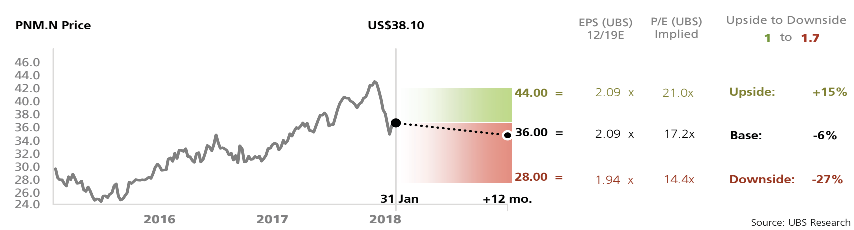
Without improved visibility and confidence in PNM's long-term earnings and rate base growth in NM, we do not find the stock attractive at its current valuation. PNM is trading at a 19% premium to the Regulated Utilities average P/E in 2019. In our opinion, PNM's share price reflects its position as one of the last remaining small-cap companies and then some.

EVIDENCE

PNM has below average regulation based on our state regulatory rankings, and below average 2017-20E earnings growth, approximately 4% for PNM vs 5.3% industry average. Historically, merger premiums have reflected an average trailing P/E multiple of 23.2x. Even applying an average 8% small cap premium to PNM, the shares appear overvalued.

WHAT'S PRICED IN?

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Multiple Premium	Ratebase	Trailing P/E	Price/Book
$44 upside			23.3x	2.1x
$36 base	8%	$3.57B		
$28 downside	-10%	$3.32B		

Source: UBS

COMPANY DESCRIPTION

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will deteriorating regulation in the U.K. result in an early rewrite of RIIO for PPL?

We doubt it. A mid-period review in 2018 of the RIIO (Revenue=Incentives+Innovation+Outputs) rate plan would more likely focus on items that are in scope and not returns which would be for 2023. The U.K. has a good regulatory tradition for long-term rate plans (currently 8 years), forward test years and decoupled rates. PPL receives incentives for customer satisfaction and its business plan. The stock prices in a significant reduction of incentives -- not just ROE exposure. Concerns stem from recommended changes to water utility regulation by OFWAT. Electric regulator OFGEM begins the RIIO 2 review in the next few months.

Q: Will the Labour Party privatize electric utilities?

Unlikely as it would be expensive and the focus has been on water and strategic energy ownership. If elected Prime Minister, Labour Party leader Jeremy Corbyn said in 2015; "I would want the public ownership of the gas and the National Grid…I would personally wish that the big six were under control, or public ownership of some form." (LabourList 8/7/15). PPL's UK distribution utilities are not in the big 6.

Q: Will PPL be able to hit its EPS growth goals?

Yes, we forecast 5 year annual EPS growth of 5.7%. F/X could provide upside as the recent surge in rates is not reflected in PPL hedges. Each $0.10 pound/dollar rate move adds 1.0% to 5 year growth. PPL's hedges through 2020 average GBPUSD 1.36. The forward curve through 2020 is 1.47.

UBS VIEW

PPL has above average EPS growth, a strong utility franchise, and the dividend is safe under various stress scenarios. The yield is 4.7%, a meaningful premium to the US RU average of 3.7%. Clarity over the mid-period review in the UK could provide a catalyst for PPL in May.

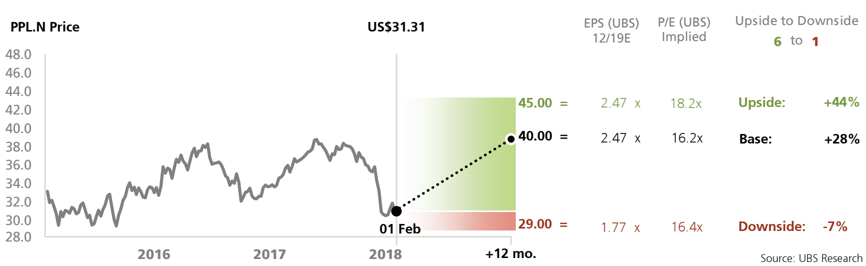
EVIDENCE

PPL's value is supported by the company's 6% rate base growth guidance, consistent track record for meeting EPS guidance and quality of the company's regulatory jurisdictions. Even in a scenario where the U.K. EPS is cut in half (consistent with the OFWAT proposal), PPL could maintain the dividend and investment grade status at a 12.5% FFO/debt. The next review of returns takes effect in April 2023.

WHAT'S PRICED IN?

The stock prices in an overly negative U.K. scenario. At an average 2019 P/E multiple the stock prices-in $0.47 of exposure to a U.K. rate review of returns which would not take effect for 5 years.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Premium/ Discount '19 P/E	Valuation Methodology	WPD ROE Reduction	UK WPD Financial ROE
$45 upside	+14%	2019 P/E	N/A	12.5%
$40 base	+17% for U.S.	Sum of Parts	N/A	12.5%
$29 downside	+0% for U.S.	Sum of Parts	$0.70	6.4%

Source: UBS

COMPANY DESCRIPTION

PPL Corporation, headquartered in Allentown, Pennsylvania, is a utility holding company that owns: PPL Electric Utilities Corporation in Pennsylvania, which serves 1.4m electric…

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will POR win the competitive IRPs and how much could that contribute?

POR would like to own or construct the assets identified in the Oregon IRP. The IRP identified a need for 100 MWa of wind and 350-450 MW of conventional capacity for 2021. POR is in the process of negotiating for the least cost conventional resource option. The result could be ownership, a purchased power agreement or construction of the assets. The wind portion will proceed to a request for proposal in which POR expects to bid. We estimate that ownership of the conventional generation could add $0.18 per share while the wind could contribute $0.12 per share in 2021. The contributions reflect $867/kw for wind and $1,100/kw for combined cycle gas consistent with figures estimated in Oregon Commission Staff testimony. We estimate 5 year rate base growth to 2022 with POR owning all the assets is 5.1% through 2022 and 3.3% without.

Q: What other investment opportunities does POR have?

Other areas include investment in grid modernization and reliability. We have not included grid modernization in our baseline but POR could redirect investment there if they do not own the IRP assets in particular. This could include transformers and underground cable replacement. Two limitations on spending in the case of success in the IRP process is rates to customers and POR's balance sheet.

UBS VIEW

We believe POR will win at least a portion of the competitive IRP and we assume the full $0.18/share for winning the RFP for the capacity resource. The company is also pursuing ownership of the wind RFP which is the best case outcome at $0.30. Alternatively POR could reallocate its cap-ex spending to other areas but it is unlikely the total spend would be greater than our forecast. Our estimates assume POR wins all of the opportunities at hand.

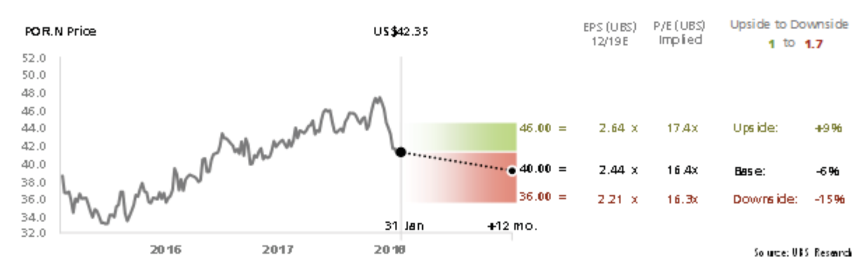
EVIDENCE

Our capital forecasts are consistent with new build forecasts developed in the IRP proceeding. POR's December 2017 rate decision was a 2.3% overall increase, but 4.2% for residential customers. We believe our modeled IRP outcome would be acceptable at a 2-3% increase on average for 2018-2019, but our upside case is likely to exceed that level and pressure customers.

WHAT'S PRICED IN?

POR stock prices in IRP wins for both the capacity and renewable resource in our view. The stock prices in a 10 year yield of 2.45% premised upon the group's under valuation vs. the Moody's Baa Bond Yield (which is 91% correlated since 1980) and a constant spread to the 10 year treasury bond

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	IRP EPS	Improved Earned ROE	'19 P/E Premium/ discount
$46 upside	$0.30	9.00%	10%
$40 base	$0.30	8.40%	3%
$36 downside	$0.18	8.00%	3%

Source: UBS

COMPANY DESCRIPTION

Portland General Electric is an electric utility based in Oregon serving 872,000 customers. The company owns over 3,400 MW of generation, which includes 41% from gas-fired...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Do PEG's nuclear plants require nuclear adders and what would they contribute?

Yes the plants benefit from hedges that expire over the next 2-3 years that largely benefit PEG's nuclear plants. We calculate that the hedges contribute $350M to nuclear margins on a mark-to-market basis for 2018 and the nuclear plants contribute little cash flow without them (excluding capacity). Nuclear adders worth $10/Mwhr would largely replace the hedges and contribute $0.46/share. The New Jersey legislature is likely to pass legislation to authorize nuclear adders by June. We believe this legislation will act as a bridge to broader market reforms.

Q: Is industry high growth at PSE&G sustainable?

Above average growth or higher is sustainable. In its general rate case filing, PEG requested recovery of $2.5B of unrecovered capital since 2010. PEG filed to extend the Gas System Modernization Plan with $2.7B of spending through 2024 and expects to file to extend the Energy Strong program.

Q: What are the impacts of tax reform?

Unregulated and well-capitalized PSEG Power helps PEG to benefit from tax reform by potentially $0.15-$0.19/share through the lower tax rate which is somewhat offset by the loss of the manufacturing tax credit.

UBS VIEW

PEG has one of the best run regulated utilities in the country and a strong balance sheet. We forecast near industry leading 5 year 8.5% rate base growth consistent with the company's 7-9% rate base target. For PSEG Power we expect the New Jersey legislature to enact nuclear adders, but PJM or other sources will also provide support long-term.

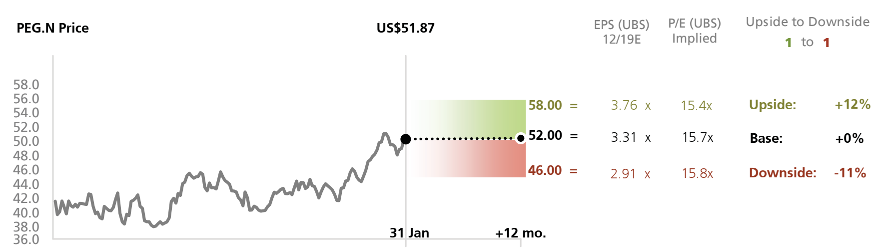
EVIDENCE

Utility PSE&G has not had a litigated outcome in New Jersey since 2010 and the company's infrastructure spending plans are consistent with the state's policy goals. Gov. Murphy has stated that keeping PEG's nuclear plants open is a priority but how is unclear "Murphy Murky on Plan to Subsidize PSEG Nuclear Plants" (NJ Spotlight 12/20/17).

WHAT'S PRICED IN?

We calculate $1-$2/Mwhr or virtually nothing for nuclear adders is in the stock. Every $5/MWhr of adders is $2/share at an 8x EBITDA multiple. We believe a 9.3% ROE in the general rate case is priced in to the stock.

UPSIDE / DOWNSIDE SPECTRUM



Source: UBS Research

Value drivers	Nuclear Adders	Rate base Growth '17-'22	Utility P/E in Sum of Parts	NJ GRC vs. Base Case
$58 upside	$10/Mwhr +$0.22/shr	9.5%	17% Premium	Company Request
$52 base	$5/MWhr	8.5%	17% Premium	-$0.08
$46 downside	$0/Mwhr -$0.22/shr	7.0%	14% Premium	Same as Base

Source: UBS

COMPANY DESCRIPTION

Public Service Enterprise Group's principal businesses are Public Service Electric & Gas (PSE&G); PSEG Power; PSEG Long Island and PSEG Service Corporation. PSE&G is the largest...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will South Carolina Regulators and Legislators Allow the D/SCG Merger?

The D/SCG acquisition offers greater customer benefits than SCG's prior stand-alone proposal that was roundly rejected by the legislature and regulators. However, rhetoric from the legislature since the acquisition announcement, and House passage of a bill that would temporarily halt bill collections for Summer, lead us to only assign a 50% probability to this outcome.

Q: Will regulators and legislators provide for a constructive regulatory outcome for SCG absent a D/SCG merger?

If the legislature repeals the BLRA retroactively, Dominion Energy will terminate their merger offer and SCG will have to look to the regulators for a more constructive outcome. We believe this would be a low probability, as regulators in SC are elected by the legislature, and the rhetoric from this body has been increasingly pointed.

UBS VIEW

We estimate the market prices in probability of close of ~58% which we believe is high given our 50/50 view. The skew of upside and downside cases is 1 to 1.4 which leads to our Sell rating. The risk to our call is deal close, and given the current state of play, we are biased negatively on the shares.

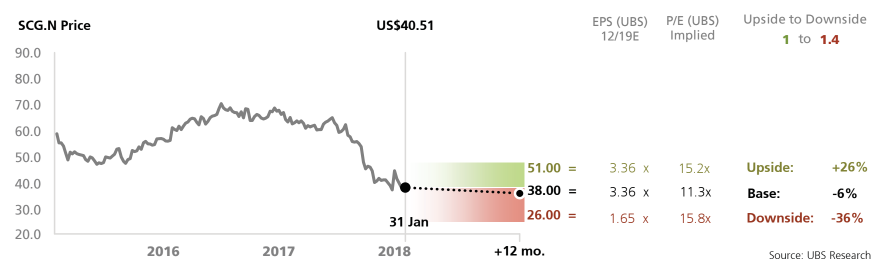
EVIDENCE

The D/SCG merger was reviewed in ex parte hearings before the SC Public Service Commission on January 11 during which we felt the Commissions views were fair. The legislature however has been more pointed in their rhetoric with Senate majority leader Shane Massey [R] calling bankruptcy a "scare-tactic". A report by ORS on January 23, indicated bankruptcy only 35% likely on BLRA repeal and could give the legislature the grounds to take action. On 1/23, SC Governor Henry McMaster said he would sign a bill that stops charging for the abandoned nuclear reactors and on 1/31 the House passed a bill that would temporarily halt cost recovery on the new nuclear project.

WHAT'S PRICED IN?

The current price is higher than our probability weighted price target indicating the market is pricing in a slightly higher probability of close of ~58% versus our 50/50 view.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Multiple Premium	'18E Equity Dividend	Annual Revenue Offset	Case to Develop EPS	Probability
$51 upside	N/A	N/A	($145)mln	D Merger Terms	50%
$38 base	10%	$1.3Bln/0% Growth	($275)mln	50/50 Wtd. Avg	50/50%
$26 downside	10%	$2.5Bln/Full Div Cut	($445)mln	BLRA Repeal	50%

Source: UBS

COMPANY DESCRIPTION

SCANA is an energy-based holding company, which is principally engaged through its subsidiaries in regulated electric and natural gas operations in South Carolina and North...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Will SRE be successful getting Oncor across the finish when others before them failed?

Yes, the third time before the TX commission looks like it will be the charm. SRE settled with all key stakeholders, committed to meet all the requirements on the PUCT's wish list, and successfully pre-funded the $9.45 billion offer price. The deadline for decision is April 3, 2018. Oncor represents $0.11/share upside to our estimates once final approvals are received.

Q: Does SRE have downside exposure to the CA wildfires?

No. Contrary to its peers in CA, SRE's only exposure is to the upside. We calculate approximately $0.09/share upside if the regulatory balance is reinstated with a return of/on the asset.

Q: What is SRE's exposure to delay at Cameron?

The EPS exposure is approximately $0.12/train for every three month delay. We include $0.19 in our 2019e EPS. Annualized earnings potential is $1.39/share. More importantly, the value of SRE is not very sensitive to small changes in schedule. Each 1Q of delay changes the NPV of the project by $0.30/share.

UBS VIEW

Sempra Energy is a well-diversified energy infrastructure company. A successful acquisition of Oncor will add regulated assets in a growing service territory to the business profile. Earnings outside SRE's U.S. regulated assets are mostly contracted, adding visibility to the earnings stream. Full commercial operation of Cameron provides a step function increase to earnings and cash flow. Currently, the stock appears to heavily discount the annualized earnings potential of Cameron and Oncor.

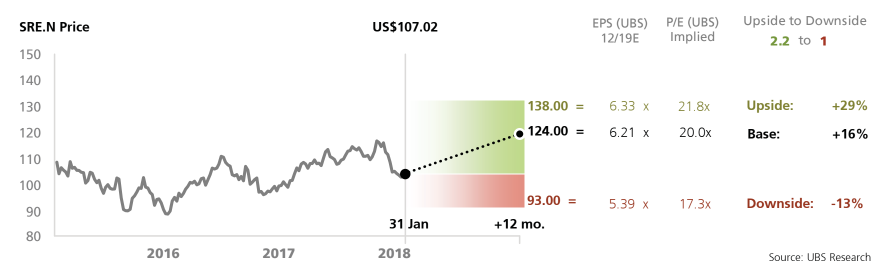
EVIDENCE

SRE wrote-off its CA wildfire exposure in 3Q17 and has not been impacted by the fires that occurred since then. In December 2017, SRE settled all outstanding claims with CBI, the lead EPC contractor at Cameron. The Oncor transaction has a high likelihood of completion given the settlement agreement with key stakeholders and capital prefunding.

WHAT'S PRICED IN?

SRE's stock price appears to heavily discount the annualized earnings potential of Cameron and Oncor. Assuming the stock reflects fair value for SRE's other businesses, at $105/share, the stock is reflecting $4 value for Cameron. This implies a 20.0x multiple on our $0.19 earnings contribution from Cameron in 2019, but ignores the full earnings potential of $1.39/share. We see no value from Oncor reflected in the stock, but estimate franchise accretion to be worth $1.50-$2 per share.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	UPO growth rate	Cameron	Cameron contribution	Oncor
$138 upside	10%	11.5x EBITDA	$800MM EBITDA	+$0.11
$124 base	8%	16.7x P/E	$352MM net inc	
$93 downside	0%	13.9x P/E	$282MM net inc	

Source: UBS

COMPANY DESCRIPTION

Sempra Energy is a holding company that operates a variety of energy-related subsidiaries. SRE's regulated electric and gas California utilities, San Diego Gas & Electric and...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Can the company achieve Vogtle new nuclear plant construction on time and on budget?

Yes, if cost and productivity metrics stay on track from current levels, but completion is five years away and that is far from certain. Post the Westinghouse bankruptcy, Southern Nuclear is now leading the project and Bechtel is the new lead contractor. As of the latest data in the 17th Vogtle Construction Monitoring report (filed every six months) costs were 2% higher than target rates and productivity was 8% below target rates as of the week of August 13. Put in context the respective ratios were 113% on cost and 79% on productivity in late March '17 when Westinghouse filed for bankruptcy.

Q: Will investors look past the ROE penalties to value the stock on longer term EPS growth?

We don't believe investors will look toward longer-term EPS growth into 2023 for some time. The Georgia Public Service commission approved the continuation of the Vogtle project in December, with a $1.4Bln increase in cost net of financing and the Toshiba guarantee payment, but applied ROE decrements of 270bps in 2021 and 470bp beginning in 2022 until Unit 4 is completed and in service. If completion of Unit 3 remains on schedule in-service is still 4 years away. Certain risk mitigating events between now then can begin to get the market more comfortable with incorporating growth from completion including: (1) successful start-up of the similar AP1000 designed new units in China, inclusion of tax credits for Vogtle in a tax extenders bill in DC, and continued execution by Southern.

UBS VIEW

We see the stock in a fair value range given Vogtle execution risk from here. We don't believe investors will look through the ROE decrements and declining earnings in 2021/22 until there is greater certainty of execution of on budget and on time completion.

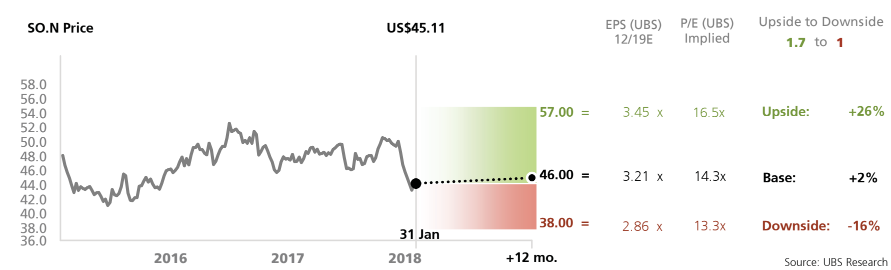
EVIDENCE

In the last nuclear construction cycle plants announced between 1966-1977 ran 207% over budget on average (Source: US DOE). Given the $1.4Bln cost increase for Vogtle and +19 month schedule delay, that the new AP1000 plants in China have not been without challenges and have yet to start up, and the cancellation of a similar project by SCANA Corp there are risks. SCANA cancellation should keep workload at the NRC limited which should help to not delay regulatory reviews for Vogtle.

WHAT'S PRICED IN?

Our $46 price target incorporates a 15% discount for Vogtle, while we estimate the current market price implies an approximate 19% discount. We believe the market is slightly over estimating Vogtle risks and lack of EPS growth but we appreciate the "prove it to me" position investors are taking with the stock. Investors do not appear to be giving any credit to potentially back filling the growth with project execution at midstream or power which could surprise.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Growth at SO Gas %/CapEx	SO Power Capex	GA Rate Case ROE Gap	PEP MS Outcome	EPS Growth Prem/Disc
$57 upside	2% / 2x Base	2x Base	0.00%	6% Hike	0%
$46 base	1%/ Base	Base	-0.84%	4% Hike	-10%
$38 downside	1%/0.5x Base	0.5x Base	-1.60%	2% Hike	-10%

Source: UBS

COMPANY DESCRIPTION

Southern Company is a diversified holding company operating 46 GWs of generation capacity, and 1,500 billion cubic feet of natural gas consumption and throughput capacity, with...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Is there upside to WEC's rate base growth forecast?

Yes. We estimate WEC's rate base could increase approximately $300MM, with no incremental capital investment. The Tax Cuts and Jobs Act eliminated accelerated depreciation for utilities. Further, we expect implementation of deferred tax normalization rules to be beneficial to rate base growth industry-wide. Higher rate base growth would support the higher end of WEC's 5-7% earnings growth rate.

Q: Should investors be concerned with management succession?

This is not an imminent concern, but should be on the radar. While the quality of C-suite management is always a contributor to stock performance, WEC's outsized premium reflects investors' confidence in this management team's track record. Gale Klappa, CEO, joined WEC in 2003 and led WEC from May 2004 to May 2016, when he retired. Allen Leverett, who had been with WEC almost as long as Klappa, made a seamless transition into CEO. A health issue caused Leverett to unexpectedly step away from the company in October 2017 and Klappa returned, first as interim CEO and now in a permanent capacity. WEC's consistent earnings growth and regulatory relationships are attributed in large part to Klappa and Leverett, who are both well-regarded by investors. While we know Klappa, 66, is committed to WEC, and Leverett may be able to return in the future, management succession is a new question for WEC investors.

UBS VIEW

WEC shares trade as they deserve to: with a top quartile premium to the group average, supported by a best-in-class management team and track record of consistently delivering earnings and dividend growth. WEC's high premium puts the stock at greater risk to relative underperformance should RUs close the gap to interest rates.

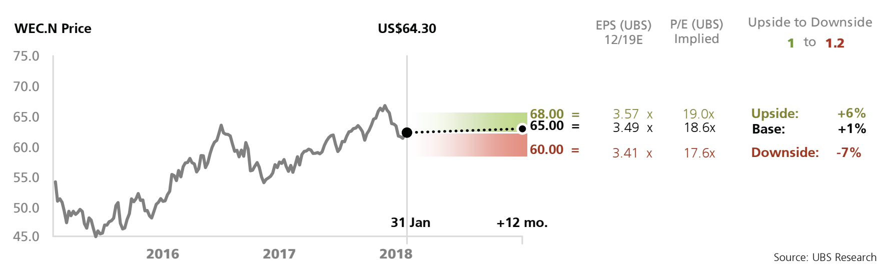
EVIDENCE

WEC has met or exceeded initial earnings expectations in each of the past twelve years. Management has demonstrated effective cost control levers in both the short-term (responding to quarterly weather variations) and long-term (consistently earning the allowed return).

WHAT'S PRICED IN?

WEC's share price amply reflects the company's top quartile regulator ranking and 5-7% earnings growth. Our model forecasts 6% earnings growth, which could go higher with incremental rate base growth. The stock also reflects best-in-class management with a consistent track record.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Premium	Ratebase
$68 upside	20%	22.0B
$65 base	17%	21.5B
$60 downside	10%	21.0B

Source: UBS

COMPANY DESCRIPTION

WEC Energy Group operates electric generation and distribution and natural gas distribution utility assets. The company services approximately 4.4 million customers in Wisconsin,...

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PIVOTAL QUESTIONS

Q: Will the merger with GXP close and when?

Yes the merger is likely to close in June following final approval from the Kansas Corporation Commission June 6 decision deadline. We believe the all stock deal addresses the KCC's concerns over leverage and has received shareholder approval. We estimate 15% merger accretion in year 1 using 70-80% of synergies retained for shareholders and accretive to long-term EPS growth at 6-8%. WR shareholders get a 15% dividend increase. Shareholders participate in a 22% stock buyback over the first 2 years.

Q: Are WR's metrics above-average as a standalone company?

No. We estimate 5 year EPS growth of 4.4% for WR versus 7.3% for the merged company. WR's standalone ranking on regulation is better but still below average with a mix of Kansas (81%) and FERC (19%) of 2016 rate base. The average regulatory ranking standalone is 24 versus 26 merged..

Q: What are the implications of tax reform?

Cash flow could impact FFO/debt ratios although the combined company is solidly investment grade with FFO/debt in the high teens (18-20%). Tax reform is a -$0.03 to -$0.05/share EPS impact by 2021 and could push the FFO/debt to the lower half of the range.

UBS VIEW

The revised merger will close and provides benefits for shareholders and for customers, in our view. The stock is close to fair value in the short term but there is material downside to not closing. The transaction provides numerous benefits over the long-term including 2-3% accretion to EPS growth which is additive to dividend growth assuming a 60-70% payout ratio.

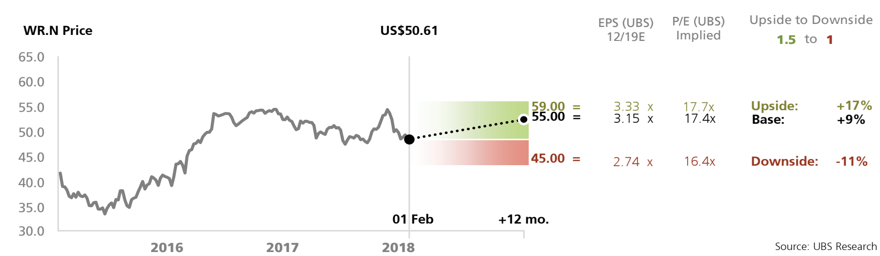
EVIDENCE

The company provided more detail on the merger synergies which is in Steve Brusser's testimony from docket CPE-095-MER. The companies target 15% cost reductions which supports the growth goals. We assume 80% retention of synergies and $1.25B of GXP's cash to help fund the buyback. Including the impacts of tax reform we model $3.34 versus guidance of $3.18-$3.50 in 2021 which is 6-8% growth from 2016 and adjusted to exclude COLI.

WHAT'S PRICED IN?

WR stock prices in a 10 year yield of 3.04% premised upon the group's under valuation vs. the Moody's Baa Bond Yield (which is 91% correlated since 1980) and a constant spread to the 10 year treasury bond. Our downside scenario reflects a 3.72% yield.

UPSIDE / DOWNSIDE SPECTRUM



Value drivers	Merger Outcome	Merger Synergies	Break Fee	P/E Premium/ Discount
$59 upside	Closes	$144M	N/A	+10%
$55 base	Closes	$88M	N/A	+10%
$45 downside	Breaks	$0	$190M	+3%

Source: UBS

COMPANY DESCRIPTION

Westar Energy is the largest utility in Kansas, with 707,000 customers and 6,573 MW of generation. The company has announced an agreement to merge with Great Plains Energy...

UBS Research THESIS MAP a guide to our thinking and what's where in this report

PIVOTAL QUESTIONS

Q: Would approval of the Colorado Energy Plan move the needle on rate base growth?

Yes. Approval of the $1.5 billion investment plan would add approximately 80 basis points to XEL's 2018-2022 rate base growth, increasing it from 5.5% to approximately 6.3%. The Colorado Energy Plan (CEP) is not included in the capital forecast in our model. We calculate approximately $0.15 potential earnings contribution from full execution of the Colorado Energy Plan, if approved. This is reflected in our upside scenario. Execution on the CO Energy Plan would also contribute to moving renewables to 47% of XEL's energy mix in 2027 from 20% in 2016.

Q: What impact will tax reform have on XEL?

Initially, we calculate modest dilution of ~$0.04 due to the reduction in the tax shield on holding company interest expense. Longer term, tax reform should contribute to higher rate base growth with no change in capital investment due to lower deferred taxes. XEL is working with regulators in its jurisdictions to consider options to pass tax savings back to customers, as well as preserve credit metrics. New equity beyond the $385MM currently included in the five-year plan may be an option to preserve credit metrics.

UBS VIEW

We see shares as fairly valued. XEL generally has constructive relationships in its jurisdictions. The focus on renewables is well received by regulators in most states and is an investment theme with increasing investment appeal. Approval of the CO Energy Plan would be incrementally positive as it would drive higher rate base growth. There is execution related to constructing approximately 3,000MW new wind generation.

EVIDENCE

The wind settlements in TX and NM provide an easier path to approval, impacting $1.6B capital spending. XEL received a substantial number of bids for the CO Energy Plan and no material parties are opposed to the proposal. Several states have already opened dockets on the impact of tax reform.

WHAT'S PRICED IN?

In our view, the shares are fairly reflecting XEL's prospects for 5-6% earnings growth. We forecast earnings at the high end of the range. Translated to bond pricing, we calculate WEC is discounting a 2.81% 10-year T-Note yield.

UPSIDE / DOWNSIDE SPECTRUM

Value drivers	2019E P/E Premium	Incremental Capex
$52 upside	20%	+$1.5B
$47 base	10%	
$41 downside	1%	-$1.5B

Source: UBS

COMPANY DESCRIPTION

Xcel Energy is a holding company headquartered in Minneapolis, Minnesota, with four primary electric and natural gas utility subsidiaries. The company serves approximately 3.6...

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Valuation Method and Risk Statement

Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 5 categories. These are as follows: 1) Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%; 2) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 5% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 5% discount; 3) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 5%, second quartile 2%, third quartile -2% and fourth quartile -5%; 4) Multi Utility Diversified Valuation: For multi utilities (those with more than 15% diversified or foreign earnings), we perform a sum-of-parts analysis applying business/region appropriate valuations to those diversified businesses; 5) One-off Adjustments: In special situations, we value risk on an issue specific basis. Common areas where we apply such an adjustment include: ESG advantage, large project construction risk, legal risk, and announced M&A completion risk. We identify the following risk factors for the sector overall: rising interest rates; regulatory and policy risks; operational risks; construction risks; cybersecurity risk to the transmission grid and/or customer data, and extreme weather events.

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12-Month Rating	**Definition**	**Coverage**[1]	**IB Services**[2]
Buy	FSR is > 6% above the MRA.	46%	27%
Neutral	FSR is between -6% and 6% of the MRA.	39%	24%
Sell	FSR is > 6% below the MRA.	16%	13%
Short-Term Rating	**Definition**	**Coverage**[3]	**IB Services**[4]
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 31 December 2017.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
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UBS Securities LLC: Daniel Ford; Ross Fowler; Gregg Orrill; Rose-Lynn Armstrong.

Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
AES Corp[16]	AES.N	Neutral	N/A	US$11.56	31 Jan 2018
Alliant Energy Corp[16]	LNT.N	Neutral	N/A	US$39.75	31 Jan 2018
Ameren Corp[16]	AEE.N	Neutral	N/A	US$56.63	31 Jan 2018
American Electric Power Inc[2, 4, 5, 6a, 7, 16]	AEP.N	Buy	N/A	US$68.78	31 Jan 2018
CMS Energy Corp[16]	CMS.N	Neutral	N/A	US$44.75	31 Jan 2018
Consolidated Edison Inc[16]	ED.N	Neutral	N/A	US$80.36	31 Jan 2018
Dominion Energy Inc[4, 5, 6a, 6c, 7, 16]	D.N	Buy	N/A	US$76.44	31 Jan 2018
DTE Energy Co[2, 4, 5, 6a, 7, 16]	DTE.N	Neutral	N/A	US$105.64	31 Jan 2018
Duke Energy Corp[2, 4, 5, 6a, 7, 16]	DUK.N	Buy	N/A	US$78.50	31 Jan 2018
Edison International[7, 16]	EIX.N	Neutral	N/A	US$62.53	31 Jan 2018
Entergy Corp[7, 16]	ETR.N	Neutral	N/A	US$78.69	31 Jan 2018
Eversource Energy[7, 16]	ES.N	Neutral	N/A	US$63.09	31 Jan 2018
Exelon Corp[7, 16]	EXC.N	Buy	N/A	US$38.51	31 Jan 2018
FirstEnergy Corp[16]	FE.N	Buy	N/A	US$32.90	31 Jan 2018
Great Plains Energy Inc[16]	GXP.N	Neutral	N/A	US$31.12	31 Jan 2018
Hawaiian Electric Industries Inc[16]	HE.N	Sell	N/A	US$34.11	31 Jan 2018
NextEra Energy Inc[4, 6a, 7, 16]	NEE.N	Buy	N/A	US$158.42	31 Jan 2018
OGE Energy Corp[16]	OGE.N	Neutral	N/A	US$32.20	31 Jan 2018
PG&E Corp[7, 16]	PCG.N	Neutral	N/A	US$42.43	31 Jan 2018
Pinnacle West Capital Corp[7, 16]	PNW.N	Neutral	N/A	US$79.95	31 Jan 2018
PNM Resources Inc[7, 16]	PNM.N	Sell	N/A	US$38.10	31 Jan 2018
Portland General Electric Co[16]	POR.N	Sell	N/A	US$42.35	31 Jan 2018
PPL Corp[2, 4, 6a, 6c, 7, 16]	PPL.N	Buy	N/A	US$31.87	31 Jan 2018
Public Service Enterprise Group[7, 16]	PEG.N	Neutral	N/A	US$51.87	31 Jan 2018
SCANA Corp[4, 5, 6a, 7, 16]	SCG.N	Sell	N/A	US$40.64	31 Jan 2018
Sempra Energy[6a, 6c, 7, 16]	SRE.N	Buy	N/A	US$107.02	31 Jan 2018
Southern Co[2, 4, 5, 6a, 6b, 6c, 7, 16]	SO.N	Neutral	N/A	US$45.11	31 Jan 2018
WEC Energy Group Inc[16]	WEC.N	Neutral	N/A	US$64.30	31 Jan 2018
Westar Energy Inc[16]	WR.N	Neutral	N/A	US$51.66	31 Jan 2018
Xcel Energy Inc[16]	XEL.O	Neutral	N/A	US$45.64	31 Jan 2018

Source: UBS. All prices as of local market close.
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BGE has not demonstrated any significant changes in the economic environment faced by the Company. It is still a monopolistic provider of electric and gas distribution service that operates in a stable service area.[345] Its customer base is the same mix from its last rate base case and it does not own generation facilities. It is noteworthy that only three months passed between our determination on February 22, 2013 setting BGE's ROE for electric and gas distribution operations at 9.75% and 9.6% respectively, and the Company's current filing for a new rate case on May 17, 2013.

Finding no significant factors that justify a radical departure from the ROEs previously granted to BGE, we now turn to specific methodologies utilized by the parties. Witnesses for BGE, Staff and OPC provided similar analytical methods for evaluating a just and reasonable ROE for the Company. For example, all the parties employed the DCF analysis and ECAPM methodology. Additionally, BGE used the utility risk premium analysis. Staff used a combination of the CAPM and ECAPM methodology and Build-Up method. OPC used additionally the two-step DCF analysis and risk premium analysis. We find all of these analytical tools helpful and will not rely on any one to the exclusion of the others in making our decision. As testified by the various cost of capital witnesses, each methodology requires some level of judgment and assumptions. Considering all of the methodologies presented, we choose to keep BGE's ROE for electric distributions at 9.75% and its ROE for gas distribution operations at 9.60%. We are not persuaded by BGE witness, Dr. Avera, that BGE is entitled to an increased ROE, and we also are not persuaded by Staff and OPC that we should reduce BGE's ROE. Our

[345] Lawton Direct at 6.

PERFORMANCE EVALUATION PLAN RATE SCHEDULE "PEP-5A"

Mississippi Public Service Commission Schedule No. 28.1		
PAGE 24 of 31	EFFECTIVE DATE **January 1, 2015**	DATE OF VERSION SUPERSEDED **January 9, 2009**

APPENDIX C

Where:

R_f = The Risk Free Rate is the normalized Bond Yield on 30 Year U.S. Treasury bonds as used in the Equity Risk Premium calculation.

Beta = The Beta is the average of the betas as stated in Value Line for the same group of comparable utilities in the DCF test above. Those companies eliminated by the DCF truncation are also eliminated from this calculation

R_m = Two historical Market Risk Premiums shall be used. The first is the total return market equity risk premium for the most current year listed and the second is the income equity risk premium for the same time period. Both are found in Ibbotson Associated Yearbook.

Two projected market risk premiums shall be used. The first is the Value Line Indicated Total Return less the normalized Yield on 30 Year U.S. Treasury bonds. The second is the S&P 500 Indicated Total Return less the normalized Yield on 30 Year U.S. Treasury bonds.

2. R_m Four calculations are performed for the Standard CAPM using each of the four market risk premiums.

Empirical CAPM

3. The following version of the Empirical CAPM model shall be used

$K = R_f + 0.25 (R_m-R_f) + 0.75 \text{ Beta } (R_m-R_f)$

Where:

R_f = The Risk Free Rate is the normalized Yield on 30 Year U.S. Treasury bonds as used in the Equity Risk Premium calculation.

Beta = The Beta is the average of the betas as stated in Value Line for the same group of comparable utilities used in the DCF test above. Those companies eliminated by the DCF truncation are also eliminated from this calculation.

193. In applying his version of the ECAPM l, Mr. Hevert used an X factor of 0.25, based on published work of Dr. Morin.[242] The resulting estimates were an average ROE of 8.91 per cent and 10.54 per cent for his Canadian and U.S. proxy groups, respectively, which were approximately 80 bps larger than his estimates using CAPM.[243] Mr. Hevert's resulting estimates do not include any amounts for flotation costs.[244]

194. Dr. Villadsen used an alpha factor of 1.5 per cent, which was based on an average adjustment factor from academic literature.[245] This factor was adjusted downwards to account for differences in government bond maturities and to be conservative.[246] Dr. Villadsen's resulting ROE estimates for her Canadian and U.S. utility proxy groups are presented in Table 5 below. Consistent with her CAPM estimates, Dr. Villadsen included flotation costs and generated results under two scenarios of risk free rates and MERP.

Table 5. Dr. Villadsen's ECAPM estimates

	ROE	
	Scenario 1	**Scenario 2**
	(%)	
Canadian utility sample	9.0 - 9.5	10.2 - 10.9
U.S. gas utility sample	8.4	9.2
U.S. electric utility sample	8.2 - 8.3	9.0 - 9.1

Source: Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 54-55.

195. Dr. Booth did not use ECAPM to generate ROE estimates, but he did discuss alternatives to CAPM. Dr. Booth observed that there are a wide variety of multi-factor models, which essentially extend the one factor CAPM to include additional factors. The current 'standard' multifactor model, known as the Fama-French three factor model, includes a size premium to address the return difference between small firms and large firms and a value premium to address the return difference between value and growth stocks.[247] Dr. Booth did not use this model or advocate for its use, as he stated this model is unlikely to generate any significant value over the use of the CAPM. He noted that he included this information in his evidence to demonstrate academic support for other risk premium based models.

Commission findings

196. The use of ECAPM is an approach recognized in the academic literature and is used to address a perceived issue with the CAPM, when the CAPM-based SML is steeper than empirical evidence suggests it should be. The ECAPM adjusts the SML by introducing an empirical adjustment factor to flatten the SML.

242 Exhibit 20622-X0215, response to AML/EDTI-AUC-2016FEB18-007, PDF pages 79-80. Transcript, Volume 1, pages 139-140.
243 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 76.
244 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 124.
245 The academic literature references are listed in Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendices, PDF page 27.
246 Transcript, Volume 5, PDF pages 647-648.
247 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 42-43.

197. In exchanges with Commission counsel, both Mr. Hevert[248] and Dr. Villadsen[249] agreed that the empirical adjustment factor used in their respective ECAPMs is a function of the sample used and the time period over which the returns were examined. During the oral hearing, Commission counsel asked Mr. Hevert if there are any kinds of standards or best practices that are employed by professionals in determining what the dataset should be when estimating the empirical adjustment factor. In response, Mr. Hevert described that there have been different studies that produce a range of estimates for the empirical adjustment factor and in his view, the selection of the empirical adjustment factor will inevitably be a matter of judgement.[250]

198. Mr. Hevert's view is supported by the evidence in this proceeding with respect to the empirical adjustment factors selected by the experts who employed an ECAPM. Mr. Hevert relied on an adjustment factor based on Dr. Morin's 1989 empirical study that used data from 1926 to 1984 and Dr. Villadsen used an empirical adjustment factor based on average estimated adjustment factors from academic studies that she then adjusted downwards in order to be conservative. The studies relied upon by Dr. Villadsen used different timeframes, with none of the studies including years beyond 1991.[251]

199. In the Commission's view, the ECAPM appears to be a model that could contribute to the Commission's determination of a fair allowed ROE. Generally speaking, the Commission is supportive of models and methods that attempt to improve upon CAPM results. The Commission agrees with Mr. Hevert that the selection of an empirical adjustment factor is a matter of judgement. Based on the evidence in this proceeding, however, the Commission has been unable to assess adequately the empirical adjustment factors employed by the experts in exercising their judgement. Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding. In order for the Commission to adequately assess the judgement exercised by the experts, the Commission would require a full explanation justifying the sample and time periods adopted.

200. The Commission also notes that the empirical adjustment factors to CAPM used in the ECAPMs in this proceeding does not resolve the issues discussed in Section 6.1.4 regarding the reasonable degree of confidence in the estimated ranges for beta.

6.3 Bond yield plus risk premium model and the predictive risk premium model

201. In addition to relying on their CAPM results in estimating a fair allowed ROE, Mr. Hevert, Dr. Villadsen and Dr. Cleary presented results generated by risk premium models. All of the risk premium models presented in this proceeding are based on the fundamental assumption of modern corporate finance that risk averse investors require higher returns for bearing higher risk. In their general form, risk premium models add a premium to account for equity risk to a measure of interest rates.[252]

202. Mr. Hevert gave primary weight to the results of his CAPM and risk premium models in arriving at his recommended ROE range, and less weight to the results of his DCF model.[253]

248 Transcript, Volume 1, page 138, lines 10-20.
249 Transcript, Volume 5, page 646, lines 7-24.
250 Transcript, Volume 1, page 139.
251 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 27.
252 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 76. Exhibit 20622-X0164, response to AML/EDTI-UCA-2016FEB18-010, PDF page 29.
253 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 159.

How To Use Beta

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STOCKS

Using Beta

Andrew J. Cueter | October 02, 2012

In finance, the Beta of a security (or portfolio) is used as an indicator of its historical volatility in regards to a benchmark, generally the New York Stock Exchange (NYSE) Composite Index or the S&P 500 Index. At Value Line, we derive the Beta coefficient from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years. In the case of shorter price histories, a shorter time period is used, but two years is the minimum. Value Line then adjusts these Betas to account for their long-term tendency to converge toward 1.00. (Though the scope of this convergence is beyond our purposes here, readers can refer to M. Blume, "On the Assessment of Risk," Journal of Finance, March 1971 for further details.)

Now that we have our Beta number, what does it mean? If an equity mirrors the benchmark, then it carries a Beta of 1.00. If Stock X has a Beta of 2.00, it is expected to rise (or fall) twice as much as the movement of the benchmark. For example, if the NYSE Composite Index rises (falls) 10%, Stock X will likely rise (fall) 20%. (For a more detailed overview, see **Understanding Beta**). Beta can also be negative (infrequent but possible), which would mean that the equity's return tends to move in the opposite direction from the market's move. Moreover, there is no upper or lower bound to Beta, although it typically does not stray too far from 1.00. Finally, a Beta of zero does not mean the asset is risk-free, just that the correlation of that asset's return to the market's return is zero.

Now that we know what Beta is and its implications, how can we use it? If we were able to predict the movements of the overall market, we would simply buy high Beta stocks while the market rises, and low Beta stocks while the market is falling. However, no one is capable of timing the market over the long term. So, what should we do?

If we define a high risk asset in terms of the movement of its price, we can look towards Beta as one indicator of this riskiness. Though Beta by itself does not give a perfect indication of volatility, it does imply the direction and magnitude of movements. Using Beta as a measure of risk, we can relate this to a basic tenet of finance theory, which states that investors demand a return in exchange for assuming risk. Therefore, high-risk (or high-Beta) investments should provide a higher payout, and conversely, low-risk (or low-Beta) investments should provide a lower payout. This proposition seems reasonable and intuitive, but it may not always hold.

In a paper entitled "Re-Thinking Risk: What the Beta Puzzle Tells Us about Investing," written by David Cowan and Sam Wilderman of GMO LLC, they show just the opposite. For the paper, Beta was measured using 250-day returns of a universe of 1,000 stocks, regressed against 250-day returns of that universe. Low- and high-Beta Portfolios were then formed monthly and weighted by market capitalization, with the universe used as the benchmark. Their results present data starting in December, 1969 and show that high-Beta stocks have significantly underperformed the market (average annualized return of 7.2% vs. 10.6% for low-Beta and 9.8% for the universe), and done so with substantially higher annualized volatility (24.5% vs. 12.5% and 16.0%, respectively) and larger drawdown (-84.4% vs. -39.5% and -50.3%, respectively).

Though low-Beta may trump high-Beta over longer periods, there are some problems with solely relying on the Beta coefficient. It is a backward looking metric, and therefore may not be an accurate predictor of the future. The markets change all the time and just because a relationship held in the past does not mean it is certain to continue into the future. Also, since it is solely a statistical measure, it fails to consider underlying business fundamentals or economic developments. Consider **Altria Group** (**MO**). This stock has a Beta of 0.55 and the company primarily sells cigarettes. Due to the low Beta, we may say this is a low-risk stock. However, if for some reason cigarettes were deemed illegal to sell, this company would probably not stick around very long and any investment in the stock will likely become worthless. Solely looking at a stock's Beta will not uncover this risk.

So, back to our question posed earlier; what should we do? We propose Beta should be used as one factor in the equity analysis framework. Investors should also look at our Safety rank and Price Stability score when making investment decisions. Considered in conjunction with Value Line's fundamental research and valuation ratios, we believe investors can create a portfolio that may provide superior risk-adjusted returns over the long haul.

At the time of this article's writing, the author did not have positions in any of the companies mentioned.

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