

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**
(e-file paperless)

**MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S
INITIAL BRIEF**

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DATED: November 9, 2018

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I. Introduction

The Consumers Energy Company's projected and filed for a \$65,073,000 total electric revenue deficiency and \$57,900,000 jurisdictional electric revenue deficiency for the test year ending December 31, 2019. (Exhibit A-11, Schedule A-1.) Staff's initial filing projected that Consumers' will have \$37,642,000 total electric revenue *sufficiency* and \$44,053,000 jurisdictional electric revenue *sufficiency*. (Exhibit A-1, Schedule A-1.) Thus, the Company and Staff were about \$100 million dollars apart.

In rebuttal, Consumers Energy Company updated its projection and stated that it will experience \$49,644,000 total electric revenue deficiency and \$43,914,000 jurisdictional electric revenue deficiency for the test year ending December 31, 2019, (Exhibit A-163 (HJM-66).) In this brief, Staff has updated its projection and explains that Consumers' will have *\$40,632,000 total electric revenue sufficiency*. (Appendix A to this Brief). Additionally, with new rates effective in the instant case, the Tax Cuts and Jobs Act (TCJA) Credit A, as determined in Case No. U-20102, will cease, effectively increasing rates by an additional \$123.435 million. (Appendix A.) When Staff's \$40.632 million sufficiency is added to the \$123.435 million increase due to ceasing the TCJA Credit A, *the net rate increase is actually \$82.803 million*. (Appendix A.) Staff calculated a lower rate base, return on equity amount, and operating expenses. These areas are primarily responsible for the difference:

- i. Consumers' rebuttal projected total rate base is \$10.683 billion, while Staff's initial brief projects rate base at \$10.620 billion—\$62.827 million less

than the Company's. (Appendix B to this Brief.) Staff reduced the Company's plant in service by \$64.741 million, including adjustments to distribution, generation, and information technology and reduced the depreciation reserve, an offset to total utility plant, by \$1.911 million. (Appendix B to this Brief.)

ii. Consumers' proposed return on equity (ROE) is 10.75%. Staff's recommended ROE is 9.75%. (Appendix D to this Brief.) The intervening parties recommend ROE's at or below 9.5%. Staff's ROE reduces the Company's projected revenue deficiency by about \$60 million. Staff's ROE differs from the Company's by 100 basis points based on differing ROE inputs.

iii. Consumers rebuttal projects that its total company operating expenses will be \$3,726,011,000, while Staff initial brief projects that they will be \$3,713,517,000—\$12.494 million less than the Company projects. (Appendix C to this Brief.) Staff's proposed operating expenses are primarily lower because Staff adjusted the Company's operation and maintenance (O&M) expense to reduce the Company's information technology O&M expense, customer experience O&M expense, customer experience – marketing and strategy O&M expense, and incentive compensation O&M expense. Staff's disallowances are justified and supported by record evidence. Staff strikes a balance between Consumers' interests and its ratepayers' interests. Public utilities are entitled to earn a reasonable rate of return on their

investments, *ABATE v Public Service Comm*, 430 Mich 33, 39 (1988), and, in turn, ratepayers are entitled to just and reasonable rates. The just-and-reasonable-rate doctrine is “aimed at navigating the straits between gouging utility customers and confiscating utility property.” *Verizon*

Communications, Inc v FCC, 535 US 467, 481 (2002). Staff’s adjustments are well within these bounds.

Staff recommends “just and reasonable rates that are fair to both ratepayers and the company.” *In re Detroit Edison Co Electric 2007-2008 General Rate Case*, MPSC Case No. U-15244, 12/23/2008 Opinion and Order, p 11, Doc. No. 567.

Consumers’ proposes some rate increases that are justified, and many that are not. In several instances, the Company has failed to justify its sharp increases in capital-expenditure and operating-expense projections. In other instances, the Company has ignored Commission precedent and asked to recover expenses that it has requested before and been repeatedly denied.

Staff’s adjustments correct these excesses. The Company’s increases in distribution spending have not yet been shown to be justified; thus, Staff favors a measured approach, making sure that the dollars go toward the proposed updates in the Electric Distribution Infrastructure (EDIIP) Report. (MPSC Case No. U-17990, Doc. No. 434) The EDIIP, a five-year projection, contains mostly aspirational goals, rather than concrete projects. (MPSC Case No. U-17990, Doc. No. 434.)

To be clear, Consumers has not proved its need for a \$43.914 million jurisdictional electric rate increase. Staff's 9.75% ROE gives the Company a reasonable opportunity to earn a fair rate of return and gives ratepayers access to safe and reliable energy at reasonable rates. Staff encourages the Company to show that increased spending will lead to improved reliability, rather than taking on proposed projects that have no granularity.

II. Revenue Sufficiency

The \$90.277 million difference between the Company's rebuttal projection of \$49.644 million total revenue deficiency and Staff's initial brief projection of \$40.632 million total revenue sufficiency is due to the following adjustments (in millions):

Rate base (revenue requirement impact)	\$ (4.9) ¹
Change in rate of return	\$ (67.0) ²
Operations & Maintenance adjustment	\$ (13.5) ³
Depreciation adjustment	\$ (2.7) ³
Property tax	\$ (0.7) ³
Sales Revenue	+ \$ (1.4) ³
Total Staff adjustments (rev. req. impact)	\$(90.3)⁴

III. Rate Base

¹ Change in rate base (\$62,827,000) x pre-tax rate of return 7.82% = (\$4.9 million) revenue requirement impact.

² Change in pre-tax rate of return (7.19% Company less 7.82% Staff) x \$10,619,912,000 rate base = (\$67.0 million) revenue requirement impact.

³ (Appendix C).

⁴ (Appendix A).

“Rate base [generally] consists of the capital invested in utility plant, less accumulated depreciation [i.e., net plant], plus the utility’s working capital requirement.” *In re Detroit Edison’s 2010–2011 Electric General Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p 5, Doc. No. 374. In this case, rate base also includes retainers and customer advances.

A. Staff recommends approving \$10,619,912,000 total rate base.

Consumers Energy’s rebuttal projected that its total electric rate base will be \$10,682,739,000 in the projected test year ending December 31, 2019. (Exhibit A-163 (HJM-66).) Staff accepted the method that Consumers used to develop its rate base projection. Staff projected that total rate base will be \$10,619,912,000, which is \$62.827 million less than the Company’s. (Appendix B and Appendix E.) The difference is due to a \$62.827 million reduction to net utility plant and no reduction to working capital.

1. Staff recommends \$9,874,142,000 total net utility plant.

The first component of rate base is net utility plant. Net plant consists of total utility plant minus accumulated depreciation and amortization. The Company proposed \$9.937 billion total net utility plant, while Staff recommended \$9.874 billion total net utility plant. (Appendix B.)

Staff’s proposed net plant is \$62.828 million lower than the Company’s because of a \$64.741 million reduction to total utility plant, offset by a \$1.911 million reduction to accumulated depreciation and amortization. (Appendix B.)

a. Staff recommends approving \$15,733,147,000 total utility plant.

The first component of net utility plant is total utility plant. Consumers recommends \$15.798 billion total utility plant; Staff recommends \$15.733 billion total utility plant. (Appendix B.) Staff proposed total utility plant \$64.741 million less than the Company because Staff reduced the Company's distribution, generation, and information technology capital expenditures. (See Section III.B and Appendix E for these capital expenditure adjustments.)

b. Staff recommends approving \$5,859,005,000 total accumulated depreciation and amortization reserve.

The second component of net plant is the accumulated depreciation and amortization reserve. Consumers projected \$5,861 billion total accumulated depreciation and amortization reserve in the projected test year. Staff recommended a \$5.859 billion reserve. (Appendix B.) Staff's recommendation is \$1.911 million less than the Company's, after adjusting the Company's capital expenditure projections. (Section III.B. and Appendix E.)

2. Staff recommends approving \$58,242,000 total retainers and customer advances.

The third component of rate base is retainers and customer advances. Staff recommends the ALJ and the Commission adopt the Company's \$58.242 million total retainers and customer advances. (Appendix B.)

3. Staff recommends approving \$804,011,000 total working capital.

The fourth component of rate base is working capital. The Company forecasted that its total working capital requirement for the projected test year will be \$804.011 million. (Exhibit A-164 (HJM-67).) Staff has accepted the Company’s projection. (Appendix B.)

B. Staff recommends several reductions to the Company’s capital expenditures.

As discussed above, Staff proposed utility plant is \$62.828 million lower than the Company’s because Staff adjusted the Company’s distribution, generation, information technology capital expenditures as shown in Figure 1 below:

Adjustment Description	Total	Test Year Impacts From Staff Adjustment(s) to Cap Ex Projects				
	Cap Ex Adj.	Plant Adj.	Accum Depr.	Rate Base	Depreciation	Prop. Tax
Distribution - New Business	(7,334)	(3,667)	(56)	(3,611)	(112)	(41)
Distribution - Reliability	(66,118)	(40,049)	(824)	(39,225)	(1,221)	(445)
Distribution- Demand Failures	(19,608)	(9,804)	(150)	(9,654)	(299)	(109)
Distribution Electric Operations Other	(11,310)	(8,577)	(694)	(7,883)	(825)	(95)
Total Distribution	(104,370)	(62,097)	(1,723)	(60,374)	(2,457)	(689)
Steam Generation Early Retirement 2023	(2,719)	(1,360)	(34)	(1,326)	(67)	(15)
IT	(1,284)	(1,284)	(155)	(1,129)	(155)	(14)
Total	(108,373)	(64,741)	(1,911)	(62,829)	(2,679)	(719)

1. Staff recommends reducing distribution capital expenditures by \$104,370,000, which is a \$60,374,000 reduction to rate base.

Staff is recommending adjustments in the following distribution capital expenditure categories: new business, reliability, demand failures, and electric operations other.

a. Staff recommends reducing distribution - new business capital expenditures by \$7,334,000.

Staff recommends that the Commission disallow \$7.334 million of the Company's projected new business capital expenditures, which is a \$3.611 million reduction to rate base. (Appendix E.)

The Company has asked to recover \$98.065 million in the 2019 test year. The Company's 2019 test year projection represents a \$24.366 million increase above the five-year average from 2013-2017. Staff recommends that the Commission disallow \$7.334 million of the Company's projected new business capital expenditures. Staff calculated its adjustments by using three-year historical actual spend levels in each of the respective sub-programs and added Staff inflation factors--2.28% for 2018 and 2.23% for 2019--as recommended by Staff witness Kirk Megginson. His testimony supports Staff's inflation calculations:

Q. Did Staff provide a forecast of inflation rates in this case?

A. Yes. Staff recommended an average inflation rate of 2.28% for 2018 and 2.23% for 2019 using June 2018 estimates from Value Line, Global Insight and the Energy Information Administration. Staff's inflation rate forecasts are outlined 21 on Exhibit S-4 Schedule D-3, page 2 of 2. [Doc. No. 342, Vol. 6, Tr 2503;[Doc. No. 344, S-4.]

Staff believes the three-year average is the most appropriate approach for new business because the number would effectively capture the recent trend for each of the associated sub-programs, and Staff's interest calculation is supported by the record.

New business capital costs are expenditures largely initiated by customers, and the Company does not have advanced knowledge of the number and costs for

the work, as stated by Company witness Andrew Bordine in his direct testimony. (Doc. No. 333, Vol. 4, Tr 1143.) Witness Bordine states that the Company bases its projection on historic amounts. (Vol. 4, Tr 1143.)

Since there is no ability to plan for new business, which in most instance arises during a given year, Staff also believes the most reasonable and reliable approach to arriving at a projected spend amount for the 2019 test year is to use a historic average for the high voltage distribution HVD strategic customer new business sub-program. Staff chose a three-year average, excluding 2016, which was an anomalous year as explained in greater detail below. Staff acknowledges that the new business spend amounts have increased steadily (Attachment A to Exhibit S-14.4, line 1), in recent years which is why a three-year average was selected as opposed to a five-year average. (Doc. No. 344, Exhibit S-14.4.)

The low voltage distribution (LVD) lines new business sub-program adjustment also consists of a 5% forecasted growth as projected in Company witness Andrew Bordine's direct testimony (Doc. No. 333, Vol, 4, Tr 1144-1145), and the (HVD) strategic customer new business sub-program included 2018 and 2019 inflation levels as recommended by Staff witness Megginson. This was rounded up to \$7.8 million by Staff as a way to account for the potential of additional new business requests.

The Commission order in the Company's previous electric general rate case requires the Company to provide more information and support for the new business program, regarding historical variability in loading rates, which have

significant cost. The Commission stated in the last general rate case its desire to receive more information regarding historical variability in loading rates:

However, because of the historical variability in loading rates, and their significant cost, the ALJ recommended that the Commission require Consumers to provide more information and support for this cost element in future rate cases. There were no exceptions to the ALJ's recommendation. The Commission agrees with the PFD and adopts the ALJ's findings and conclusions with respect to this issue. [*In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, p 12, Doc. No. 489]

Contrary to the Commission's Order, the Company did not adequately support its spending with the additional required information regarding historical variability in loading rates.

Company witness Bordine's testimony (Doc. No. 333, Vol. 4, Tr 1145) describes the 20% increase in underground installations, which occurred in 2017. Witness Bordine did not provide evidence as to why a substantial increase in installation would occur again in the 2019 test year. In discovery, the Company pointed to a waiver, granted in MPSC Docket No. U-18039, which allegedly would increase installations, by waiving certain cost-requirements for customers. *In re application of Consumers Energy Company for a waiver of Rule 511*, 2/3/2016 Order, Doc. No. 2. While Staff acknowledges that the waiver granted by the Commission's 2/3/2016 Order is some evidence of a possible increase, it is not sufficient to justify such a substantial increase in a short period for projected year 2019.

The waiver granted on an *ex parte* basis in MPSC Docket No. U-18039 allows the Company to waive the requirements of Rule 511, regarding certain customers contributions in aid of construction (CIAC). Michigan Administrative Code, R

460.511. The Commission's June 9, 2016 Order states the parameters of the waiver:

Rule 511 requires that for all underground extensions of electric distribution facilities covered by the Commission's rules, the real estate developer or customer shall make a contribution in aid of construction to the utility in an amount equal to the estimated difference in cost between overhead and underground facilities. For purposes of Rule 511, "distribution facilities" are defined as those operated at 15,000 volts or less to ground for connected systems and 20,000 volts or less for delta connected systems.

The Commission granted Consumers' waiver, as a way to allow Consumers to be more competitive. Consumers' application requested authority to waive the requirements of Rule 511 in situations "in which the revenues associated with new load are sufficient to recover Consumers' costs of providing service to the new load, including the difference in the costs of providing underground electric service and overhead electric service."

Company witness Bordine did not show the details of the impacts the waiver has on its projections in the 2019 test year, and simply presents the waiver along with increased underground installations as justification for a substantial increase in the spend category for test year 2019, based on the 2016 spend levels. There has not been shown to be a link between the 2016 increase and the 2019 projection, especially considering lowered spending in 2017 and 2018.

In Company witness Bordine's testimony, the Company challenged Staff's rationale for excluding the 2016 actual spend levels for HVD new business and claims, as an anomaly. Witness Bordine states that Staff provides no justification for why a three-year historical average, excluding 2016, is an appropriate means for

determining the Company's spending plan, as opposed to the Company's projections. (Doc. No. 333, Vol 4, 1285.) Witness Bordine's statement is puffery and ignores Staff's concerns. Witness Bordine states that the Company's "projected spending level for the 2019 test year is based on detailed analysis and planning for the various investment categories comprising the LVD Lines Reliability program." But, witness Bordine has no detailed analysis or concrete evidence to back-up his statements. Witness Anderson also takes issue with witness Becker's proposed \$2.2 million reduction in New Business Capital Spending. (Doc. No. 334, Vol. 5, Tr 1956.) The Company took a five-year average and did not exclude 2016 spending, requesting a little less than that five-year average. *Id.*

Because the Company's proposed increases in distribution spending have not yet been shown to be justified, Staff favors a measured approach. Despite the length of the Consumers' Electric Distribution Infrastructure (EDIIP) Report, Staff submits that it is a high-level outline of the Company's intent over the next five years. Staff does not disparage the EDIIP Report. Rather, Staff would like to see the aspirational proposals unfold into solidified plans before assigning dollars to them. The EDIIP, a five-year projection, contains mostly goals, rather than concrete projects. (MPSC Case No. U-17990, Doc. No. 434.) It is true that projections need flexibility but also true that the Company has *not* shown that 2016 is a characteristic year, or that late emerging projections in 2018 are likely to be completed in 2019. As the Company admits, Exhibit A-17 (JRA-2), page 1, 15, line 4, cites "anticipated projects yet to be specifically identified." (Doc. No. 334, Vol. 5,

Tr 1958.) While Staff acknowledges that it is legitimate for new business projects to be considered by Consumers in late 2018, those projects should not be included in the projected test year for this case, as they have no demonstrated likelihood of completion in 2019.

The Company attempts in rebuttal to show greater granularity and details regarding projects emerging in 2019. The Company stated that there is an additional HVD strategic customer new business project emerging near St. Johns; however, Company witness Anderson testified that the Company has “identified additional HVD New Business projects for potential construction in 2019.” (Doc. No. 334, Vol. 5, Tr 1958.) The statement that the Company has *identified potential construction* is evidence that the project is merely in its nascent stages. (*Id.*) Further, it was not publicly announced until August 2018 and, if completed, may not even take place in the projected test year of 2019. Despite 2016 actuals, 2019 will not likely be a year with an uncharacteristic high spend since there are only \$3.540 million worth of determined projects set to take place in 2019 as shown in Exhibit A-24 (JRA-9). Staff realizes that there is the potential for additional HVD strategic customer new business projects in the 2019 test year. They are not concrete or likely to the extent the Company claims. Namely, the \$2.8 million project near St. Johns contains pending execution agreements demonstrating that the project is not full-fledged and not destined to complete in 2019. (Vol. 5, Tr 1958.) Staff does not disagree that a new project *could* emerge late in 2018 but disagrees that such a project is likely to be completed in in the 2019 test year. The

detailed analysis that the Company claims it possesses, to prove spending is appropriately projected for 2019, is simply not in the record.

The ALJ and the Commission should adopt Staff's recommendation and not allow the Company to collect projected spend amounts beyond the historical three-year average, appropriately excluding the anomalous year. Staff believes the adjustments have provided the Company with the flexibility needed to compensate for the level of uncertainty for new business projects for the 2019 projected test year.

b. Staff recommends reducing distribution – reliability – capital expenditures by \$66,118,000 because the Company has not proved it will actually spend the amounts proposed.

i. The Company lacks support for sharp increases in capital spending.

The Company also fails to justify its capital spending projections. Staff recommends that the Commission disallow \$66.118 million of the Company's projected reliability capital expenditures, which is a \$39.225 million reduction to rate base. (Appendix E.) Broken out, Staff recommends reducing reliability capital expenditures by \$13,980,000 in the 2018 bridge year and \$52,138,000 in the 2019 test year.

The Company has asked to recover \$227.134 million in the 2019 test year consisting of projected spend increases of over \$38.3 million in communications upgrades and \$27.5 million in grid capabilities, including, advanced technologies, above the five-year average. It is not clear what level of spend increase the

Company is requesting for the 2018 bridge year in the reliability capital spend category since the Company has failed to provide detailed information to support the \$96 million overspend with no insight as to what sub-programs the overspend took place above 2018 approved spending levels approved by the Commission in MPSC Case No. U-18322. *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, Doc. No. 489.

The Company's 2019 test year projection represents a \$118.850 million increase above the five-year average from 2013-2017. Staff recommends that the Commission disallow \$13.980 million of the Company's 2018 bridge year expenditures and \$52.138 million of the Company's 2019 test year reliability capital expenditures. Staff calculated its adjustments in multiple different ways throughout the reliability spend categories, including using a five-year historical actual spend levels, using recent spend levels, and allowing a portion of increased spend, depending on what was most appropriate. Most adjustments include Staff inflation factors. Staff inflation factors were all applied at a percentage of 2.28% for 2018 and 2.23% for 2019 as recommended by Staff witness Megginson in his direct testimony. (Doc. No. 342, Vol. 6, Tr 2503.)

ii. A five-year average is appropriate as an initial basis for capital reliability spending.

Staff believes considering the five-year average for projected spending is an appropriate approach for reliability because that period would effectively consider both recent and longer trends for each of the associated sub-programs. Some sub-

program adjustments were made by Staff based on the previous year's spend amounts while other were numbers that Staff believed were adequate in considering the affordability of rates to the customers while still supporting a given program. Staff is also committed to ensuring that rates remain affordable for customers and would like to see increases, such as the substations communications upgrades, be spread out over a longer period of time to soften the rate impact. Staff has various issues with the Company's spend amounts in the reliability program. The basis for Staff's recommended downward adjustments include, but are not limited to, invalid estimates, inadequate proof of the reasonableness for projected spend amounts, and pending contracts and pilots which fail to adequately support spending in a given reliability spend program.

iii. Undetermined and ill-determined proposed capital spends are a concern.

Staff's testimony highlights the large amounts of undetermined spend in the Company's filed case. In rebuttal, Company witness Anderson explains that the Company has identified projects for undetermined spend in the LVD substation reliability spending sub-program and proved that there are no longer any animal mitigation or regulator replacement projects which are undetermined. (Doc. No. 334, Vol. 5, Tr 1967.) The additional detail provided is helpful to Staff. This does not, however, address Staff's concern that the average cost for animal mitigation work is above the average cost for work. The Company provided a larger dataset of 24 projects rather than 11 projects in Exhibit S-14.4 (Doc. No. 344), discovery

response 20134-ST-CE-105, from 2018 which shows that the average cost to update a substation to the current animal mitigation standards is \$75,300. The most recent average cost for animal mitigation installations is still well below the average cost of \$100,000 as projected in the Company's direct testimony and confirms that the Company has, in some cases, projected higher costs to perform work than what is anticipated. (Doc. No. 344, Exhibit S-14.4.)

The Company states its intent to "accelerate its installation plans" and perform more animal mitigation substation work, if the amounts requested are approved, and if the costs are lower than projected. (Doc. No. 334, Vol. 5, Tr 1969-1970.) Staff is concerned, however, that the Company has failed to prove that this additional work, beyond the 40 planned substations, could be completed in the 2019 test year.

Staff has misgivings, as well, about the Company's failure to provide justification for its proposals regarding new control houses, including failure to show that the control houses are needed. Staff is also concerned that the plans for both upgrades and new control houses both should have and have not been shown to comply with the National Electrical Safety Code (NESC) standards. Witness Anderson's rebuttal attempts to address Staff's concern that the response to discovery 20134-ST-CE-357 was incomplete and did not contain the measurements required to justify the new control houses. (Doc. No. 344, Exhibit S-14.4, p 7; Doc. No. 334, Vol. 5, Tr 1971). Witness Anderson states his concerns with current control houses, which he believes require upgrades:

The Company's supplemental response to discovery 20134-ST-CE-357, Exhibit A-124 11 (JRA-19), contains the voltage to ground and clear distance measurement condition(s) not met relative to the National Electrical Safety Code ("NESC") working space Table 125-1, establishing the need for a new control house at these six substations. NESC Table 125-1 can be found in Exhibit A-125 (JRA-20), which was provided to Staff in Attachment B of 15 discovery response 20134-ST-CE-35 [Doc. No. 334, Vol. 5, Tr 1971.]

Attachment C, however, does not contain *any* actual measurements or voltages to support that the proposed work is both necessary to comply with NESC working space standards and will meet those standards upon completion. It simply asserts, without providing the evidence, that the voltage to ground and clear distance measurements were not met as shown in 20134-ST-CE-357. (*Id.*) Staff does not believe, however, that the Company has sufficiently provided the necessary information since *no* actual measurements were provided through initial and supplemental responses to discovery to support the NESC working space projected work, as both needed and compliant.

Staff also has a concern that there is a lack of pilot evidence to support the prudence of new grid modernization investments and contracts that the Company's grid modernization spend plans are prudent. During rebuttal, the Company did not share or confirm the results of pilots to prove the reasonableness of grid modernization investments, nor did the Company adequately prove grid modernization work will be complete. Company witness Anderson's rebuttal attempts to assure that substation communications upgrades work will be complete by stating, "[t]he Request for Proposal process for the 2019 projects currently not contracted is on track to be in place on time to meet the project schedule." (Doc. No.

334, Vol. 5, Tr 1971.) Company witness Bordine similarly attempts to assure that the Advanced Distribution Management System (ADMS) contracts will be in place and complete for the 2019 test year by stating “[t]he Company is on track to complete contract negotiations with both the project vendor and System Integrator by year-end 2018.” (Doc. No. 333, Vol. 4, Tr 1298.) He assures that contracts are in place, saying “[t]he Company is meeting the current capital spend and deployment units for 2018 and finalizing addition contracts to support 2019 work plan.” (Vol. 4, Tr 1301.) Staff acknowledges the fact that the Company has set a goal, however the use of the phrases “on track” and “finalizing addition[al] contracts” reinforces that the work is *not* yet fully procured, and the potential is there that the work will not be executed within the projected 2019 test year in compliance with Public Act 286. Public Act 286, Section 6a(1) states in part that that, “A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges.’ PA 286 allows “projected costs,” not hypothetical costs. As identified in testimony and above, Staff questions the validity of the Company’s estimates in the reliability program. The Company, in Staff’s opinion, has not adequately provided evidence to support spending in its sub-programs. Without a clear implementation plan and timeline to support the Company’s spending plan, Staff has no way of determining whether or not the expenses projected by the Company are reasonable and prudent.

iv. 12-year pole inspections cycles go unobserved, adding unneeded costs to capital spending.

Staff is also concerned that the percentage of LVD poles that have not been inspected in the current 12-year cycle is contributing to higher reliability and demand failure spend amounts. As outlined in the response to discovery 20134-ST-CE-353, approximately 80% of the Company's LVD poles have not been inspected in the current 12-year cycle as recommended in Staff's November 20, 2009 report on utilities pole inspection programs. During rebuttal, the Company appears to have misconstrued the issue, thinking that simply reducing the number of poles replaced is key, when inspections to identify the most at-risk poles is more cost-effective.

In recent years, the Company has had a history of over projection and at times underspend in the reliability program. In the Commission Order from the Company's most recent rate case, Case No. U-18322, the Commission states the Commission finds it most reasonable to limit approved amounts to historical levels, until such time as the company demonstrates a true commitment to these programs. [*In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, Doc. No. 489, p. 14.]

The Staff has reason to doubt the Company's projections in reliability spend, as the Company intended spend in other areas, when evaluated with granularity, has not been shown to be prudent. One of example of this is the Company's failure to use reasonableness and prudence with respect to pole replacements. As the Company also admits, witness Becker evaluated with granularity (i) poles replaced due to inspection; (ii) pole replacement versus pole remediation; and (iii)

prioritization of targeted circuit improvements. Staff found the mis-spending in these categories, coupled with lack of important details provided by the Company in other categories, to show that the Company's projections were not reliable in general. (Doc. No. 333, Vol. 4, 1286.)

The ALJ and the Commission should adopt Staff's recommendation and not allow the Company to collect spending amounts at the level the Company is projecting, when it has not shown it is likely to spend at projected levels. Staff does not believe the Company has properly supported the levels of reliability spend increase. Staff adjustments have provided the Company with the ability to spend on various reliability sub-programs, while softening the rate impact to customers.

c. Staff recommends reducing distribution – demand failures – capital expenditures by \$19,608,000.

Staff recommends that the Commission disallow \$19.608 million of the Company's projected demand failures capital expenditures, which is a \$9.654 million reduction to rate base. (Appendix E.)

The Company has asked for recovery of \$151,826,000 in the demand failures program for the 2019 projected test year which represents an increase of nearly \$30 million above the five-year average of actual expenditures from 2013-2017. Staff recommends that the Commission disallow \$19,608,000 for the 2019 projected test year which consist of HVD and LVD demand failures based on the belief that the most reasonable projection is based off of the historical actual spend amounts which are driven by failures or immediate defects discovered through inspections.

Staff's 2019 projected test year adjustment has built-in inflation for 2018 and 2019 and added \$5 million above the 5-year average in an attempt to compensate for the variability and uncertainty of the spend category. Similar to all other spend categories, "Staff inflation" factors as specified in direct testimony were all applied at a percentage of 2.28% for 2018 and 2.23% for 2019 as recommended by Staff witness Megginson. Staff adjustments were made to be used as motivation for the Company to explore more cost effective and timely corrective action after inspections. Staff's adjustments were also implemented to show that although the demand failures are generally out of the Company's control, the Company has led Staff to believe that maintenance activities, or lack thereof, have likely contributed to the level of increased demand failures.

Company witness Anderson assumes that Staff approves of HVD projections by the Company since direct testimony refers to LVD specifically.

Therefore, my interpretation is that Mr. Becker agrees with, and approves of, the Company's HVD Demand Failures capital expenditures of \$29,467,000 in 2018 and \$30,672,000 in the projected test year ending December 31, 2019, as set forth in 22 Exhibit A-12 (JRA-1), Schedule B-5.4, page 2, line 4, columns (c) and (f), respectively. [Doc. No. 334, Vol 5, Tr 1974.]

Staff does not agree with this self-serving statement by the Company. Although Staff's direct testimony describes findings related to LVD only, the purpose of the testimony is to provide proof that the Company has evidently relaxed their maintenance program, rather than reporting their actions. With respect to maintenance, the Company is required to track asset deterioration of the system, in order for the Company to replace assets before they fail.

The Company claims that the LVD Lines Demand Failures are largely due to presumably unavoidable “asset deterioration on the system.” (Doc No. 333, Vol. 4, Tr 1296.) The Company has a duty to avoid such failures, through early and routine maintenance. Company witness Bordine emphasizes that “the Company is not at a point where the age of its assets creates critical reliability and resiliency issues,” but that the age of the infrastructure will result in the need for more spending. (Vol. 4, Tr 1209.) Staff, too, is concerned with the failure to properly address aging infrastructure; Staff wants to make sure that the Company does so in an economical and prudent manner, allowing for proper review by MPSC Staff.

In rebuttal, Company witness Bordine appears to confuse matters, perhaps to conceal the concrete fact that 80% of the LVD poles owned by the Company have not been inspected in the current 12-year cycle as supported in discovery response 20134-ST-CE-353. Witness Bordine states in rebuttal that he interprets “reducing poles outside of the recommended range to mean a reduction in the rejected pole backlog.” (Doc No. 333, Vol. 4, Tr 1287.) Witness Bordine tries to make it sound like simply reducing the “rejected pole backlog,” without regard to the order that poles are replaced and without regard to trying to fix problems before they arise, is the most effective way to reduce failures.

At the heart of the matter and ignored by the Company’s testimony is the fact that the Company is not able to meet the recommended 10-12-year LVD pole inspection frequency, and as a result, has driven up the failure rate of poles when they are inspected, leading to increased reliability costs, and escalating demand

failure costs. Like brakes on a car, the poles need to be inspected and replaced before they are at extreme likelihood of failure.

R 460.3504 entitled “Electric plant inspection program” requires a pole inspection program and states that:

Each utility shall adopt a program of inspection of its electric plant to ensure safe and reliable operation. The frequency of the various inspections shall be based on the utility’s experience and accepted good practice. Each utility shall keep sufficient records to verify compliance with its inspection program.

Staff issued a pole inspection report on November 20, 2009 to the Company recommending a 10 to 12-year inspection cycle for poles in the system. The Company has since targeted this frequency but appears to be unable to meet this frequency for LVD poles. The Company is required to maintain its system and cannot ignore the pole inspection guidelines without consequence.

Company witness Bordine asserts that a reduction in spending on demand failures when there is a recent increasing trend is inappropriate. (Doc. No. 334, Vol. 5, Tr 1287.) Staff proposes, however, that the Company not fail to conduct routine maintenance, then act in emergent way, which is not cost-effective. Rather than replacing all failed LVD poles as quickly as practicable, the Company should be urged to remediate the failures, in an economical way, and reduce the number of poles that have not been inspected in the current 12-year cycle. This would improve the system and lower the capital costs. The intent of the adjustment is to motivate the Company to consider more cost-effective and timely methods of remedial action after a pole has failed the pole inspection to allow the Company to reduce the amount of LVD poles outside of the current 12-year pole inspection time period.

Witness Bordine, assumes again that Staff's main goal is simply to reduce the backlog of rejected poles, when he states that "it is not reasonable to assume reducing the backlog of rejected poles results in a reduction of poles replaced under LVD Demand Failures when the Company is replacing additional poles in various other programs." (Doc. No. 334, Vol. 5, Tr 1289.) Staff proposes also reducing the number of non-inspected poles, which should lead to fewer demand failures, even accounting for possible weather events.

The ALJ and the Commission should adopt Staff's recommendation and not allow the Company to raise rates based on the spending the level the Company is projecting, when the Company has failed to take preventative action that could reduce spending and improve reliability.

The five-year historical average is the most reasonable measure for reliability capital spend, since the actual amounts are not known and there is a level of uncertainty in projections. Staff adjustments have provided the Company with the ability to spend based on historical demand failure levels and has included additional spend amounts for flexibility needed to compensate for the level of uncertainty of the demand failures program.

d. Staff recommends reducing distribution – electric operations other – capital expenditures by \$11,310,000, which is still a 50% increase for the 2018 bridge year and a 25% increase for the 2019 test year

Staff recommends that the Commission disallow \$11.310 million of the Company's projected electric operations other capital expenditures, which is a

\$7.883 million reduction to rate base. (Appendix E.) Staff recommends reducing electric operations other capital expenditures by \$5,844,000 in the 2018 bridge year and \$5,466,000 in the 2019 test year.

The Company asked to be allowed \$10.1 million for the 2018 bridge year and \$10.8 million for the 2019 test year. Staff recommended using the 5-year average from 2013-2017 outlined in Exhibit A-38 (AJB-4), line 40, column h, which are the basis of Staff's adjustments. Staff's adjustments allowed for a 50% increase for the 2018 bridge year and a 25% increase for the 2019 test year.

In its rebuttal, the Company argued that basing the Company's future requirements on historical spending is unreasonable because the Company cannot invest to improve on its performance if the investment levels are strictly based on history. The Company states that the North American Electric Reliability Corporation (NERC)/National Electric Safety Code (NESC) work is transferred from the NESC account to other sub-programs and is not accurately reflected in the 5-year average. Staff realizes the uniqueness of the NESC working space account and is reluctant to reduce spending in that category. Staff is compelled to make the adjustment because the Company has failed to adequately support that the work is necessary and prudent. The measurements for this type of work were not provided in discovery request 20134-ST-CE-357, as explicitly specified above at page 19 of this brief; thus, Staff has no way to know if the funds are needed or likely to be properly spent.

Also, in rebuttal, Company witness Anderson assures that the Company did not receive a request from Staff for voltages and measurements relative to working space requirements, rather he states that the request in 20134-ST-CE-357 (Exhibit A-124) only requested the specific measurement information within the substations communications upgrades sub-program, not the electric operations other. (Doc. No. 334, Vol. 5, 1978.) Staff is responsible for reviewing and making a recommendation to the ALJ and Commission regarding the reasonableness and prudence of projected capital investments, and Staff has not been provided measurements to support that the electric operations other NESC working space work is necessary. The Company's claim that the Staff did not request the information in the same way as it did for the projects in the sub-stations communications upgrades sub-program falls short. (Doc. No. 334, Vol. 5, 1978.) This assertion missing the point, as the burden of proof is on the regulated utility to show that the spending request is valid, the measurements were required by the Staff to complete its prudence review. The Company could have and did not timely provide the information, in order for Staff to conduct its review.

For the reasons above, the ALJ and the Commission should adopt Staff's recommendation and not allow the Company to collect spend amounts at the level the Company is projecting. Staff believes the five-year history is the most reasonable with 50% and 25% increases in 2018 and 2019, respectively, since the company has failed to adequately support spend amounts in the 2018 bridge year and also support amounts requested with respect to the NESC working space work.

2. Staff recommends reducing steam generation capital expenditures by \$2,719,000, which reduces rate base by \$1,326,000.

Staff recommends that the Commission and ALJ reduce steam generating capital expenditures by \$2,719,000, based on the retirements of Karn 1 and 2, proposed in the Company's integrated resource plan (IRP) filing. Staff witness Bodiford testified that "Staff remained consistent with the Company retirement proposal in the IRP and identified the projected expenditures associated with the Karn Units 1&2, 2023 early retirement scenario (Exhibit A-61 (JPB-4) p 1 of 2, line 19) of \$2,719,000." (Vol 6, Tr 2411-2412.) Company witness Broschak agreed in part with Staff and testified that "Staff's recommendation is consistent with the Company's proposal to retire Karn Units 1 and 2 in the IRP proceeding." He claims, however, that the Commission should adopt the Company's calculations in Exhibit A-61 (JPB-4), which "illustrates the Company's unavoidable, avoidable, and incremental capital expenditures in 2018 and 2019 at Campbell Units 1 and 2 and Karn Units 1 and 2 (collectively the 'Medium 4') under different scenarios in which those units are retired in 2021 or 2023." (Vol 7, Tr 3254.)

Staff made no adjustments to the suggested avoidable costs set forth by the Company. The Company's recommendation regarding avoidable costs and early retirement of Karn units 1 and 2 were accepted as testified to. And in following with the ALJ's recommendation in the order for case U-18322, Staff again believes that it is reasonable to disallow the outlined expenditures and "err on the side of caution," as the expenses may be avoided, which is what Staff requested in Case No. 18322. *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC

Case No. U-18322, 03/29/2018 Order, Doc. No. 489, p 22. Staff's rationale was adopted by the Commission in its decision in Case No. 183322 where it held that "the Commission agrees with the Staff and MEC/NRDC/SC, that it is reasonable to err on the side of caution and defer \$1.6 million in test year avoidable costs for the Karn units." *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, Doc. No. 489, p 24. Staff submits that there is no reason to deviate from that holding in this case.

In summary, Staff recommends removal of analogous early retirement expenditures in this case, based on a history of the same, including (1) the inclusion of Karn units 1 & 2 as potential early retirement units with avoidable costs in Consumers rate case Nos. U-18322 and U-2013; (2) the proposed early retirement of these same units in Consumers IRP case No. U-20165; (3) Staff and the ALJ's recommendations for removal of early retirement units' avoidable expenditures in rate case No. U-18322, and; (4) the subsequent decision of the Commission in U-18322 to exclude the early retirement avoidable costs associated with Karn units 1&2 for the test year. It is Staff's opinion, furthermore, that removal of these expenditures should happen independently of any decision yet to be made in the Company's IRP filing U-20165 because as was also upheld in the Commission's decision in order No. U-18322, "As the ALJ pointed out, the deferral does not foreclose future recovery if any amounts are prudently spent." *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, Doc. No. 489, p 24.

3. **The Commission should exclude \$1,284,000 from Consumers' projected information technology (IT) capital expenditures, which is a \$1,129,000 reduction to rate base.**

The Commission should reduce the Company's projected information technology capital expenditures by \$1.284 million, which is a \$1.129 million reduction to rate base. (Appendix E.) Staff continues to support removal of the amounts it originally advocated for removing in initial testimony, including the amounts now conceded by the company, and also the remaining difference between Staff and the Company, as illustrated and discussed in greater detail below.

Staff IT Adjustment Summary			
	Plant	Accum Dep	Rate Base
Staff Total IT Adjustment at Initial Filing	\$ (5,535,761)	\$ (465,693)	\$ (5,070,068)
Company Concessions at Rebuttal			
IT - ARP Storage Project	(2,036,000)	123,000	(1,913,000)
IT - Legal Archiving Tool	(500,000)	30,000	(470,000)
IT - Customer Experience Improvement	(800,000)	48,000	(752,000)
IT - ARP WAM Project	<u>(916,000)</u>	<u>110,000</u>	<u>(806,000)</u>
Total Concessions	<u>(4,252,000)</u>	<u>311,000</u>	<u>(3,941,000)</u>
Remaining Difference for Staff Disallowance at Initial Brief	<u>\$ (1,284,000)</u>	<u>\$ (154,594)</u>	<u>\$ (1,129,406)</u>

- a. **The Commission should disallow the non-supported capital expenditures for the Company's IT ARP—Storage difference between Staff's adjustment of \$4.071 million, based on the originally field requested amount, minus the Company's concessions, in rebuttal.**

Staff requests that the unsupported IT ARP (asset refresh program)—Storage project be disallowed. The Company originally requested \$5.553 in capital expenditures (Exhibit A-84 (JRH-3) p 28, line 199) for its IT ARP (asset refresh program)—Storage project. (Doc No. 326, Vol. 2, Tr 261-262, 299.) Staff recommended in direct testimony that \$4.071 million of the requested be adjusted in this rate case. (Doc No. 342, Vol. 6, Tr 2418-2419.) (Now, \$2.036 million in plant has been conceded in rebuttal testimony, and Staff requests that the remaining difference be adjusted for Staff's recommended disallowances.) (Exhibit A-165 (HJM-68.))

This project is to refresh storage assets that have more than 5 years of continuous service and provides incremental storage capacity as needed. As part of its analysis, Staff asked the Company to provide the number of storage assets refreshed in 2016 and 2017 and the number planned for 2018 and 2019 as well as the unit cost of each asset type. (Doc No. 342, 6 Tr 2418.) The Company instead supplied the type of storage unit installed or planned for install, the total number, and the total cost because of variation in costs of the same type of unit. (Doc. No. 344, Exhibit S-9.3, p 5.) S-9.3 shows that in the test year the Company plans to install 4 Nutanix devices that have a total cost of \$977,646.00. Company Exhibit A-84 (JRH-3) p 28, line 199 shows the ARP—Storage project having a material cost of

\$5.049 million. Due to a lack of supporting evidence for the remaining \$4.071 million, Staff recommends the Commission disallow the capital expenditures that cannot be supported by record evidence, recognizing that \$2.036 million has now been conceded.

b. The Commission should disallow the materials cost for the Company's Legal—Archiving Tool for Email, Archiving Tool for Email, Chat, File share, and Sharepoint project due to a lack of clarity on the storage solution.

The Company has requested an estimated \$1,000,000 in capital expenditures for the materials portion of its Legal—Archiving Tool for Email, Chat, File share, and Sharepoint project. (Since that time Company has conceded \$500,000 of plant in service with respect to the request.) (Exhibit A-165 (HJM-68.)) Staff submits that it is premature to allow this request at this time.

The Company claims that these funds are necessary for servers and additional storage. When Staff inquired about the nature of the material cost it was revealed that at the time the case was originally filed, the Company was planning to use an on-premise option for the new archive solution. (Doc. No. 344, Exhibit S-9.3, p 6.)

However, since the filing of this case the Company has begun to consider an alternative solution which would use Office 365. Staff issued additional audit questions and the Company explained that if the solution were to change to Office 365, then some of the requested expenditures would need to shift from capital to O&M. (Doc. No. 344, Exhibit S-9.3, p 8.) As a final decision will not be made until

the third quarter of 2019 regarding which solution the Company will select, Staff recommends the Commission disallow the \$1 million (which includes the amount conceded in rebuttal of \$500,000 in plant) associated with the planned on-premise solution because it is no longer the expected solution, but one of the possible solutions. Depending on which solution is chosen, it may change the nature of the funding.

c. The Commission should require the Company to include additional information in its initial filing of IT expenditures.

In its direct testimony Staff recommends that the Commission require the company to submit a list of information (as follows) its initial filings. Staff maintains that this request is appropriate and ripe for a Commission order.

-Future IT project-level detail should include a breakdown of both the O&M and capital costs. O&M costs should be broken down into two or three sub-categories.

-For each project the Company should submit a project approval document after the project preliminary analysis phase that includes:

1. A brief synopsis describing the project
2. The project approval date
3. The incurred expenditures to date (Operations and Maintenance Cost (O&M))
4. The total project estimated O&M and capital cost through project implementation
5. Any necessary approvals by the Company's management with appropriate expenditure approval authorization (per documented company policy.)

6. Any approved change management documentation if the total project estimate grows by greater than 10% or \$50,000 (whichever is greater). For IT projects over \$100,000, the Company will include as an exhibit. The Company will include as an exhibit a copy of the written, PowerPoint, or other media presentation that the Company's technical staff used to present the project justification and alternatives considered by Company senior management.

-Analysis that shows the Company considered cloud computing alternatives in IT project expense requests over \$100,000 excluding cyber security or transmission control IT projects. [Doc. No. 342, Vol. 6, Tr 2422-2423.]

Staff recommends that because the above criteria are submitted does not mean that cloud-based solutions will automatically be approved by the Commission, nor preclude parties from challenging the expenses. (Doc No. 342, Vol., 6 Tr 2422-2423.) Staff made this same recommendation in the Company's gas rate case, Case No. U-18424, which was included in the Settlement Agreement, at pp 3-4, attached to the 8/28/2018 Order approving and incorporating that agreement. *In re Consumers Energy Company 2017-2018 General Natural Gas Rate Case*, Case No. U-18424, Doc. No. 343. In that agreement, the Company agreed to provide all of the information "[a]t the time of filing in future rate cases." *Id.*, p 3 to Settlement Agreement, attached to Order. Staff believes that this information is still appropriate for the Company to include in future filings, and it is worth re-iterating in the Commission's order in this electric rate case.

- d. **The Commission should disallow the recovery of \$1.6 million in capital expenditures from the Company's Customer Experience Improvements project for inappropriate and unsupported costs,**

recognizing that the Company has conceded part of the originally claimed amount.

The Company's Customer Experience improvements project is made up of improvements to New Outage Center, Move-in and Move-out, Billing & Payment Field Capability, Content Personalization, Gas Leak Response Tracker, Integrated Rates Experience/Interval data Portal Replacement, and Super User, which facilitates payment and management of customers with multiple business accounts.

Staff recommended, in direct testimony, that the Commission disallow the \$1.1 million the Company has allocated to the Gas Leak Response Tracker portion of the project. As Staff testified, this is a general electric rate case and the recovery of project expenditures that are associated with the Company's gas business is inappropriate. (Doc No. 342, Vol. 6, Tr 2420.) (Since Staff's direct testimony, the Company has conceded in rebuttal \$800 million in plant.) (Exhibit A-165 (HJM-68).)

Staff also recommended that the Company disallow the \$0.5 million associated with the Field Capability portion of the project. The Field Capability initiative is intended to allow the Company's field members to invoice and accept payment from customers in instances of customer-requested services like the extension of a gas line or installation of new electric service. (Doc No. 342, Vol. 6 Tr 2420.) The benefits that Staff asked the Company to provide for this program were improved back-office efficiencies as well as increased customer satisfaction. Staff also asked the Company what other utilities were employing similar technology. The only instance the Company was aware of was CenterPoint Energy's Home

Service Plus (HSP) Field Sales. (Doc. No. 344, Exhibit S-9.3 p 3.) As witness Fromm stated in her direct testimony, this example is a value-added service that is non-regulated. (Doc No. 342, Vol. 6, Tr 2421.) Because costs associated with the system development to allow for this capability are not recovered through customer rates, Staff does not find this to be a credible or applicable example. The Company has not supported this expenditure as reasonable and prudent. Monetary operational benefits were not provided by the Company. Therefore, Staff recommends the capital expenditure of \$0.5 million associated with this program be disallowed.

e. The Commission should disallow the \$1.3 million “overhead & other costs – electric” costs that the Company has not supported.

In the Company’s ARP—WAM (workstation asset management) program \$2.256 million is categorized as “overhead & other costs—electric”, which is nearly half of the total \$5.182 million project cost for the year 2018. *Id.* The Company has conceded part of the request. Company witness Josh R. Hall states, “[T]he Company agrees to reduce its request in this case from \$2,256,000 to \$1,339,926.” (Doc. No. 326, Vol. 2, Tr 289.)

As the ARP-WAM allocation was significant itself, and significantly higher than in other years, Staff asked the Company through audit to explain the discrepancy. The Company’s response was “Beginning in 2018, IT assumed the entirety of the Company workstation budget of approximately \$2.2M. For forecasting and monitoring purposes, the \$2.2 M was placed into the “overhead &

other costs—electric” category. As equipment is ordered and charged to the project, this amount will reduce throughout the year and the charges will accumulate in the “material costs—electric” category.” (Doc. No. 344, Exhibit S-9.3 p 7.) This is an insufficient explanation to justify this expenditure. This expenditure cannot be tied to any particular plan or scope of work. (Doc. No. 342, Vol. 6, Tr 2422.) This expenditure is essentially the same as a contingency expenditure. Staff has consistently recommended that the Commission disallow all contingency expenditures because they cannot be evaluated for reasonableness and prudence at the time they are presented as projected expenditures based on certain contingencies occurring. The Commission has consistently concurred with Staff’s recommendation to disallow contingency expenditures.

Company witness Josh Hall argues that the costs are tied to specific plans with a table he supplies as additional evidence in rebuttal testimony that provides a list of devices, how many of each were actually purchased and projected to be purchased in the year 2018, a total dollar amount and an average per unit cost. The total witness Hall provides is approximately \$1.34 million, which he recognizes as less than the original request of \$2.2 million and recommends the Commission only disallow the difference of the two figures, \$916,074, allowing the full \$1.34 he currently requests. (Doc. No. 326, Vol. 2, Tr 289.) However, what is missing from this additional evidence is a unit cost for each of the items provided.

The Company is planning to purchase 3 different types of laptops, 2 different types of desktops, and one type of Toughpad, a rugged tablet, with office and vehicle

dock. *Id.* As the amounts of these fluctuate between the four quarters, so does the average unit cost. For example, in the first quarter the average unit cost is \$2,023 whereas the third quarter average unit cost is \$3,006. *Id.* Without any information on how the unit cost changes between each type of laptop, desktop, and Toughpad, these figures cannot be verified in any way. Staff recommends, therefore, that the Commission disallow the \$1.3 million (originally \$2.2 million, as filed in its application) that the Company has included in “overhead & other costs—electric” in this case for equipment purchases. (Doc. No. 326, Vol. 2, Tr 289.)

4. The Commission should disallow all projected contingency expenditures totaling \$19.3 million in the test year and \$17.2 million in the bridge year, as conceded by the Company for purposes of this case.

The Company has requested contingency expenditures totaling \$19.3 million in the test year and \$17.2 million in the bridge year. The company withdrew the request to include contingency in its rebuttal. Company witness Myers rebuttal testimony states “For purposes of this rate case, the Company is no longer pursuing recovery of this item.” (2 TR 354).

These expenditures are components of the projected capital expenditures from Electric Distribution, Generations Capital Expenditures and Information Technology, which are broken out by project on Exhibit S-9.0. (Doc. No. 344.) Staff recommends that the Commission disallow all contingency expenditures because it is inappropriate to receive recovery of expenditures that are budgeted for uncertain or unforeseen events occurring. These expenditures cannot be judged for

reasonableness and prudence at the time they are presented. Also, to earn a return of and on expenditures that may not be incurred in full if at all does not reflect acceptable ratemaking to the ratepayers. (Doc No. 342, 6 Tr 2417.)

The Commission has previously disallowed contingency expenditures in each of the Company's general electric and gas rate cases since the general electric rate case, Case No. U-17735. Additionally, the Company has withdrawn its request to include contingency in its capital expenditure projections. *In re Consumers Energy Company 2014-2015 Electric General Rate Case*, MPSC Case No. U-17735, 11/19/2015 Order, pp 106-109, Doc. No. 381. Therefore, Staff recommends that these contingency expenditures should also be disallowed.

IV. Capital Structure and Rate of Return

A. Overview

Staff recommends an overall after-tax rate of return of 5.81%, which consists of a recommended return on equity (ROE) of 9.75% and an equity percentage of 51.83%. (Doc No. 342, Vol. 6 Tr 2493.) The Company recommends an overall after-tax cost of capital of 6.33% with a ROE of 10.75% and an equity layer of 52.50% in the permanent capital structure. (Doc. No. 333, Vol. 4 Tr 811.) The 52- basis point disparity between Staff and the Company's overall rate of return stems primarily from a lower balance and cost rates assigned to common equity, long-term debt and short-term debt. Staff's recommendation is sensitive to the Company's position, relative to Intervenors.

The Attorney General's (AG) witness Sebastian Coppola recommends an overall cost of capital of 5.62%, based on a ROE of 9.50% and an equity layer of 50%. (Doc. No 342, Vol. 6, Tr 2829.) The Association of Businesses Advocating Tariff Equity (ABATE) witness Billie LaConte recommends a ROE of 8.77% with an equity layer of 52.0% (Doc No. 336, Vol. 7, Tr 3364.) Residential Customer Group (RCG) witness William Peloquin recommends the Company's equity layer as a percent of permanent capital structure be set no higher than 52.0%.

B. Capital Structure Ratemaking Component Development

1. Staff recommends a common equity balance of \$7.24 billion.

Staff recommends a common equity balance of \$7,240,345,774, which represents approximately 51.83% of the permanent capital structure and 41.25% of the ratemaking capital structure. (Doc. No 342, Vol. 6, Tr 2496.) Staff developed its equity balance by using actual equity balances through June 2018, and then estimated retained earnings similar to the Company's methodology through the test year ending December 31, 2019. Staff included the Company's proposed equity infusions into its equity profile but modified the projected 2019 equity infusions. The Company projected a January 2019 equity infusion of \$300 million and a June 2019 infusion of \$350 million. Staff modified the January 2019 infusion to \$200 million to the June 2019 infusion \$100 million. (Doc. No 342, Vol. 6, Tr 2497.) Staff contends that the Company received equity infusions no higher than \$250 million in the past 10 years, that Consumers Energy has not received equity infusions in

excess of \$300 million since May of 2007, and that Staff's recommendation is more in line with past infusions and similar to infusions received in 2018. (Doc No. 335, Vol. 6, Tr 2497-2498.)

Contrary to Staff's position, Consumers Energy's witness Andrew J. Denato opposes Staff's infusion adjustment. The Company contends that the equity infusions are planned, needed and consistent with the capital needs of the company and that Staff did not account for its upcoming investment requirements and additional capital needs due to the passage of the Tax Cuts and Jobs Act of 2017 (TCJA). (Doc. No. 333, Vol. 4, Tr 848-851.)

Witness Denato is not correct. As Staff pointed, in its testimony, out that the infusions projected from the parent did not always match reality. In Consumers Energy's last electric rate case, Case No. U-18322, the Company projected a \$200 million equity infusion from its parent in January 2018 but received only \$100 million. (Doc No. 335, 6 TR 2497-2498.) Thus, projected infusions are not set in stone and are subject to change or cancelation. During cross examination, witness Denato stated that he was part of the equity infusion planning process. (Vol. 4, Tr 910-911.) However, witness Denato did not know what average infusion amounts the Company had received from its parent, did not know if infusions exceeded \$300 million recently and did not know if the parent ever infused funds that were more or less than it projected. (4 TR 911-913.) Even more to the point, the Company admitted that equity infusions from the parent are not mandatory. (Vol. 4, Tr 913.) Staff did not reject the Company's proposed 2019 infusions as unnecessary but

modified them to more sensible levels. Staff testified that the Company's inflated infusion projections had no recent precedent and Staff's equity ratio of 51.8% was more in line with the Commission's objective of a more balanced capital structure for Consumers Energy going forward. (Doc No. 335, Vol. 6, Tr 2498.)

Witness Denato agreed that equity was a more expensive form of capital than long-term debt. (Doc. No. 333, Vol 4, Tr 908.) It follows that too much equity is a weighty burden on ratepayers, and that adding to ratepayer expense unnecessarily is not appropriate. Thus, the Company's criticism of Staff's revised infusions for 2019 based on its claim that Staff did not consider the Company's ongoing capital needs is without merit; rather, the Staff attempts to balance the need for equity with the need for affordability by ratepayers. The Commission should reject the Company's plea for a higher common equity balance and adopt Staff's reasonable recommendation.

2. Staff recommends a long-term debt (LT-Debt) balance of \$6.69 billion with a cost rate of 4.47%.

Staff recommends a LT-Debt balance of \$6,692,616,000, which represents approximately 47.91% of the permanent capital structure and 38.13% of the ratemaking capital structure. (Doc No. 335, Vol. 6 TR 2496.) Staff recommends a cost rate of 4.47%. (Doc No. 335, Vol. 6, Tr 2500.) Staff's LT-Debt balance matches that of the Company's recommendation. In rebuttal, the Company agreed to Staff's 4.47% recommendation. (Vol. 4, Tr 859.) Therefore, Staff recommends that the Commission adopt its recommendation.

3. Staff recommends a short-term debt (ST-Debt) balance of \$154 million with a cost rate of 4.14%.

Staff recommends a ST-Debt balance of \$154,000,000, which is consistent with the Company's ST-debt balance recommendation. (Doc No. 342, Vol. 6, Tr 2499.) Staff initially recommended a ST-Debt cost rate of 3.35%. However, Consumers Energy opposed Staff's ST-Debt cost rate in rebuttal, contending that Staff's failure to recognize the cost related to the renewables liability component of its ST-Debt estimate was incorrect and understated the cost of ST-Debt. (Doc. No. 333, Vol. 4, Tr 861-862.) Including the renewables liability component in Staff's ST-Debt cost rate increased the rate to 4.14%, which was about equal to the Company's proposed ST-debt cost rate of 4.16%. (Vol. 4, Tr 863.) Staff recommends allowing the cost related to the renewables-liability component of its ST-Debt only for this case, recommending that in future, it should not be included.

Staff maintains that the renewables liability are funds already collected from customers, and more importantly, do not contribute to the actual cost rate of the Company's short-term debt. Staff notes that including that balance with a cost rate in ST-Debt results in a misaligned and inflated cost rate that is burdensomely high to ratepayers. (Doc. No. 342, Vol. 6 Tr 2501-2502.) Because Staff admits that it included the renewables liability balance cost in ST-Debt in past rate cases and, thus, can accept the renewables liability balance and cost rate in this case only. In rebuttal, the Company asserts that if the Commission were to agree with Staff's position of removing the cost attached to the renewables liability but keeping the balance in short-term debt, then the renewables liability balance should be removed

from the projected capital structure entirely. (Doc. No. 333, Vol. 4 Tr 863.) Staff agrees with this position as the optimal approach for future. The Commission should direct the Company to remove the balance and cost rate from the ratemaking ST-Debt component in future rate cases.

Consumers Energy opposes Staff's request for the Commission to review and potentially revise ongoing costs associated with the Company's ST-Debt revolving credit facilities. The Company argues that Staff was incorrect when it stated that the Company increased its revolver capacity by \$250 million when it only increased its capacity by \$200 million. (Vol. 4, Tr 866). These Company arguments only enhance Staff's position.

Staff initially believed the Company had \$600 million in revolver capacity before raising it \$250 million. Staff asked the Company if it was correct that its revolver capacity was actually \$650 million instead of \$600 million. The Company answered yes. (Vol. 4, Tr 917.) Thus, Staff notes that prior to increasing its revolver capacity, and noting that Consumers Energy prefers to finance its working capital deficiency with short-term debt (\$400 million maximum), then the Company in reality had a \$250 million cushion/safety barrier instead of \$200 million that Staff originally surmised. (Doc No. 335, Vol. 6 Tr, 2502). Consumers Energy then increased its revolver capacity an additional \$200 million to \$850 million, and then another \$250 million to \$1.1 billion. Ratepayers are paying full cost for that excess capacity, including all usage fees, non-usage fees, commitment fees, renewable fees, and any letter of credit fees associated with the revolvers. The Company notes that

it expects to have a maximum of \$325 million of short-term borrowings in the month of October 2019.⁵ (Doc No. 333, Vol. 4 Tr 868.)

Therefore, as Staff contends, the Company's initial JP Morgan revolver at \$650 million adequately covers the Company's upcoming short-term debt financing requirements with room to spare. (Doc No. 335, Vol. 6, Tr 2503.) The additional \$450 million in revolver capacity is extra padding that is expensive and adds undue costs to ratepayers. Staff recommends that the Commission should thoroughly review the Company's substantial and costly revolving credit facilities and direct the Company to absorb some of the fees associated with its excess revolver capacity to lower the cost rate to more reasonable levels.

4. Other ratemaking capital components

Staff agreed with the Company's recommended balances and cost rates and/or the recommended balance and cost rate methodology for preferred stock, deferred federal income taxes and job development investment tax credits (JDITC). (Vol. 6, Tr 2499-2500.)

C. Capital Structure Summary

As described above, Staff recommends the Commission adopt its overall cost of capital of 5.81%, predicated on a 51.83% equity layer and a 9.75% ROE. Staff requests that the Commission adopt its more rational common equity balance and not include the over-inflated equity infusions the Company requests in its

⁵ Consumers Energy Exhibit A-14 (AJD-7), Schedule D-6.

ratemaking equity balance. Staff did not reject any of the Company's proposed equity infusions but revised them to more sensible levels based on past precedent. Staff also urges the Commission to strongly consider a further revision to the Company's short-term debt cost rate. The Commission should spare ratepayers from paying unreasonably high, misaligned cost rates due to the ongoing renewables liability balance and the Company's excess revolving credit capacity. Therefore, Staff urges the Commission to fully consider its position and adopt Staff's overall cost of capital recommendation.

1. Return on Common Equity Development

a. Staff recommends a return on equity (ROE) of 9.75%.

In determining a reasonable ROE for Consumers Energy, Staff relied on the guidelines set forth by the Supreme Court's decision in the *Federal Power Comm v Hope Natural Case Co*, 320 US 951 (1944) and *Bluefield Water Works & Improvement Co v Pub Serv Comm*, 262 US 679 (1923). (Doc No. 335, Vol. 6 Tr 2504.) Staff recommends a cost of equity or ROE range of 8.75% to 9.75% and used the upper end of its range, 9.75%, in its overall cost of capital determination. (Doc No. 335; 6 TR 2504.) Because Consumers Energy is not publicly traded, Staff used a group of nine publicly traded electric utility companies to help establish a reasonable cost of equity range for the Company. (Doc No. 335; Vol. 6 Tr 2505-2506.) Staff developed its proxy group based on five criteria; 1) net plant greater than \$5.0 billion but less than \$40 billion; 2) 40% or more of revenues from

regulated electric service; 3) investment grade credit rating within three notches of Consumers Energy's credit rating; 4) dividend payment to shareholders; and 5) not involved in mergers or major corporate buyouts. (Doc No. 335, Vol. 6, Tr 2505.)

Staff used the proxy group to provide a reasonable approximation of the Company's required cost of equity from the group's statistics used in Staff's Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) cost of equity analyses. Staff also relied on a risk premium analysis and a review of other state commission ROE decisions to help reach a recommended cost of equity for Consumers Energy's electric division. (Doc No. 335, Vol. 6, Tr 2506.)

b. Staff's DCF model yielded an average ROE of 8.91%.

The DCF model derives its basis by surmising how investors evaluate stocks for potential investment. The formula assesses that investors value stocks by 'discounting' to the present the expected future cash flows attributed to those securities, which include dividends, a capitalization rate applied to the future cash flows and the projected market value of the securities at liquidation. Staff obtained the data for its DCF analysis using statistics from its proxy group and growth estimates from industry experts. Staff's DCF analysis yielded a ROE estimate of 8.91%. (Doc No. 335, Vol. 6 Tr 2507.)

Staff's analysis also addressed the Company's DCF analysis. Staff disagrees with the Company's use of only I/B/E/S growth rate estimates instead of using additional sources. (Doc No. 335, Vol. 6 Tr 2508.) Staff asserts that additional sources provide for a more expansive review of estimates and the Company used

additional sources in the past. *Id.* Staff also disagrees with the Company's use of just I/B/E/S dividend growth projections instead of earnings growth rate projections. (Doc No. 335, Vol. 6, Tr 2509.) Staff asserts that earnings growth are the basis for dividend growth and that earnings growth estimates are the preferred metric used by other intervenors. The Company also used earnings growth metrics in the past. *Id.* Staff also disagrees with Consumers Energy's 'company guidance' projections as the source of its growth rate estimates in its DCF analysis. Staff notes that the company guidance projections are, at a minimum, aggressive and not objective like outside analyst's growth rate estimates. *Id.*

Staff also disagrees with flotation cost enhancement to the DCF model or to any of the cost of equity estimates. Staff maintains that flotation costs are not borne by Consumers Energy and ratepayers should not be burdened with a cost the Company has not incurred in the past and will not incur in the future. (Vol. 6 TR 2510.) Therefore, Staff recommends the ALJ and the Commission reject the Company's DCF analysis and ROE estimate and adopt Staff's more reasonable recommendation.

c. Staff's historical & projected CAPM analysis yields an average 8.21% - 9.38% ROE estimate.

Staff provided two CAPM analyses, an historical CAPM and a projected CAPM. (Doc No. 335, Vol. 6 TR 2510 - 2513.) The CAPM describes the relationship between a security's investment risk and its market rate of return. The CAPM infers that investors are exposed to two types of risk, diversifiable (firm specific)

and non-diversifiable (market) risk. The CAPM suggests that an investor is fully invested in a portfolio of stocks and thus eliminates or greatly reduces firm specific risk and is only exposed to non-diversifiable or market risk. The risk of an asset and thus the investor's required return is a function of the risk that the asset contributes to the market. This market risk of an asset is characterized by the beta coefficient. Therefore, to estimate a cost of equity using CAPM, one needs a risk-free rate, an estimate of beta for the proxy group and a market return for a wide portfolio of assets. (Doc No. 335, Vol. 6 TR 2511-2512.) Staff used Global Insight's 30-year U.S. Treasury bond rate forecast for 2019 for its risk-free rate, the proxy group betas from Value Line and a market return from a wide variety of assets from 1952-2017 and a full range from 1926-2017 from Ibbotson 2018 Classic Yearbook. The historical model produced an average ROE estimate of 8.21% using the 1952-2017 data and 8.63% using data the 1926-2017 data. (Doc No. 335; 6 TR 2512.) Staff also provided a projected CAPM estimate using Value Line's 12-month projected median dividend yield of 2.0%, a 3-to-5-year price appreciation projection of the New York Stock Exchange of 40%, which was annualized at 10.00%, and the proxy group's betas. The projected CAPM produced a ROE estimate of 9.38%. (Doc No. 335, Vol. 6, Tr 2513.)

Staff's analysis also addresses the Company's CAPM approach. The Company provided three CAPM analyses but published the results of only two. (Doc No. 335; 6 TR 2513.) Staff disagrees with the Company's "normalized" CAPM method that uses an historical average risk-free rate as the preferred risk-free rate

in the model. Staff also disagrees with the Company's "projected" CAPM analysis that uses a blend of "low interest rate" historical timelines as well as projected timelines to establish a market risk premium in that analysis. Staff also disagrees with the Company's use of an empirical CAPM or ECAPM approach. (Doc No. 335; 6 TR 2513-2520.)

First, Staff asserts that the "normalized" CAPM method uses a historical risk-free rate that does not correspond to the forward-looking nature of this rate case, is not based on forward-looking test-year estimates for risk-free rates, distorts the investor's reasonable required rate of return, and improperly inflates the Company's cost of equity (Doc No. 335, Vol. 6, Tr 2515.) The Commission should reject the Company's "normalized" CAPM estimate.

Second, Staff asserts that the Company's "projected" CAPM method is its most flawed and erroneous. *Id.* The analysis uses historical short-period timelines along with a projected timeline to determine a "projected" market risk premium used in the analysis. *Id.* However, a short-time period to develop market risk premium data is patently improper analysis and the Company's own testimony describing the volatility of market data over short periods of time attests to that fact. (Doc No. 335, Vol. 6, Tr 2516.) Thus, Staff contends that the Company's "projected" CAPM analysis is improper analysis and produces erroneous ROE estimates. The Commission should reject this approach and its ROE estimate.

The Company produced CAPM estimates but chose to abandon those results and instead use estimates associated with its ECAPM approach. (Doc No. 327, Vol.

3, Tr 454-455). Staff asserts that the ECAPM produces erroneous results and that the approach is unnecessary for ratemaking purposes. Staff maintains that the inputs used in its CAPM analysis already capture most of the supposed shortcomings that ECAPM is purportedly designed to capture. Staff's use of long-term risk-free rates and adjusted betas in its model, incorporates much of the desired effect of the ECAPM adjustment. (Doc No. 335, Vol. 6 TR 2519.) Thus, Staff's CAPM analysis provides a reasonable ROE estimate without the need for an ECAPM adjustment, and the Commission should reject all ECAPM estimates. (Doc No. 335, Vol. 6 Tr 2520.)

d. Staff's risk Premium Method yielded average ROE estimates of 8.89% - 10.19%.

Staff provided two risk premium approaches, an historical spread approach and a projected spread approach. The risk premium method examines the spread between historical electric utility realized stock returns and historical composite utility bond yields and develops a cost of equity estimate by incorporating the historical data with current utility bond data. (Doc No. 342, Vol. 6, Tr 2521.) Staff used a return period of 1932 through 2017 to obtain its historical market premium and current average yields for A-rated and BBB-rated utility bonds. Staff also incorporated a forward-looking equity risk premium of 5.58% from Staff's Value Line Projected CAPM approach. The risk premium model produced ROE estimates of 8.89% for current A-rated bonds and 9.23% for BBB-rated bonds. The projected

spread approach produced ROE estimates of 9.86% estimate for A-rated bonds and 10.19% for BBB-rated bonds. (Doc No. 342, Vol. 6, Tr 2521.)

e. Other state commission’s authorized ROE decisions averaged 9.65% to 9.77% for 2016 through June 2018.

Staff reviewed the authorized return on equity decisions for electric utilities rendered by other state commissions for the years 2016 through June 2018. The average authorized ROE from those decisions was 9.77% for 2016, 9.74% for 2017 and 9.65% through June 2018. (Doc No. 335; 6 TR 2522.)

f. Summary of Results and Staff’s Recommendation.

<u>Method</u>	<u>Range</u>	<u>ROE Result</u>
DCF		8.67%
Historical CAPM		8.63%
Projected CAPM		9.38%
Historical Risk Premium (A-Rated Bond)		8.89%
Historical Risk Premium (BBB-Rated Bond)		9.23%
Projected Risk Premium (A-Rated Bond)		9.86%
Projected Risk Premium (BBB-Rated Bond)		10.19%
<u>Electric Utility ROE Decisions Across the U.S. (2016 – June 2018)</u>		
		<u>9.72%</u>
ROE Recommendation	8.75% - 9.75%	
		9.75%

As the data above reflects, Staff recommends a reasonable cost of equity that is above the national average. There is a national trend towards lower authorized ROEs than what Consumers Energy currently enjoys at 10.00%. Staff’s recommended 9.75% ROE is slightly below the Company’s current ROE but above

the national trend. Staff's recommendation provides Consumers Energy with a favorable return on equity based on the Company's solid capital structure, stable business and financial outlook as reflected in its credit ratings, the utility favorable attributes inherent in Public Act 286 and PA 341 and the Company's request for a risk-mitigating investment recovery mechanism. (Doc No. 335, Vol. 6 TR 2523.)

g. The Company's arguments against Staff's 9.75% ROE recommendation are flawed and meritless.

Consumers' cost of capital witness Srikanth Maddipati sponsors the Company's recommended 10.75% ROE and submitted rebuttal disputing Staff's 9.75% ROE recommendation. (Doc No. 327; 3 TR 477 & 3 TR 504-517). Company witness Shrikanth Maddipati argues that Staff's ROE recommendation is flawed because Staff does not mention or consider the negative impacts of TCJA, uses inconsistent or incorrect inputs into its quantitative models, and is inconsistent with support for the Company's credit metrics and ability to attract capital and fund its electric utility investment. (Doc No. 327; 3 TR 504-517.) As explained in detail below, these arguments are baseless and fall short of their mark.

i. The Company's argument that Staff's ROE recommendation did not account for the impact of the 2017 TCJA is inapplicable and meritless.

The Company argues that Staff's ROE recommendation did not consider the significant credit impact the TCJA had on the credit quality of Consumers Energy's electric business. (Doc No. 327, Vol. 3, Tr 486.) The Company argues that Staff

provided no substantive quantitative or qualitative analysis of the TCJA's credit implications to Consumers Electric, and Staff's lack of the TCJA recognition should give the Commission pause. (Doc No. 327, Vol 3, Tr 486.) The Company's arguments are groundless.

The Company, through discovery, requested if Staff performed a quantitative analysis of the Company's credit metrics and whether its 9.75% ROE recommendation and 51.83% equity layer would be below or above the indicated rating agency thresholds for downgrade or investment. Staff responded that the Company did not indicate a ratings threshold in their testimony. Witness Maddipati provided a rating's threshold in rebuttal. (Doc No. 327, Vol. 3, Tr 484.) Nonetheless, Staff performed two quantitative credit analyses, one using S&P's FFO/Debt ratio analysis and the other using the Company's FFO/Debt ratio equation. Staff noted that the results were similar to the Company's results using both methods. (Doc. No. 344, Exhibit No. S-22.) Thus, the Company's claim that Staff did not perform a quantitative credit rating analysis is meritless.

However, and more importantly, the TCJA did not directly affect the Company's credit metrics. Staff asked the Company during cross examination whether its credit rating was directly affected by the TCJA from either Moody's or S&P. The Company responded no. (Doc No. 327, Vol. 3, Tr 652.) Nonetheless, the Company argues that the TCJA was tantamount to a radical change that requires upward movement in the Company's ROE. (Vol. 3, Tr 478.) To that point, Staff asked the Company whether it was aware of any state regulatory commission or

any other utility company that specifically pointed out the need for an increase to authorized ROE to account for the impacts of TCJA. The Company responded that it was not aware of any state commission or utility and that TCJA was largely handled through the debt to equity ratio, not the ROE. (3 TR 653.) Thus, the Company's notion that a 75- basis point increase to its authorized ROE is necessary based on the impacts of the TCJA is misdirected and erroneous. The Commission should give no weight to the Company's testimony that the supposed all-encompassing negative impact of the TCJA requires an upward adjustment to the Company's capital structure and ROE.

The Company also broadly discusses the impact the TCJA had on a few other utilities credit metrics and how those state's regulatory commissions addressed the TCJA issue in those cases. However, other utility credit metrics have no bearing on Consumers Energy and those other utility credit metrics may have been under pressure prior to passage of the TCJA. The Company provided no evidence or support to the contrary. The Company admitted that it did not conduct any analysis or examination of the referenced utilities equity layers, capital structures or credit metrics prior to TCJA. (Doc. No. 333, Vol. 4, Tr 919-920.) Since the Company offered no analysis, holding up the referenced utilities as proof of the negative impacts of TCJA and in essence, the proper commission responses to those utilities, is erroneous and should be given no weight by the Commission. Thus, the Company's arguments regarding supposed harm to its credit quality based on

Staff's recommended ROE and equity layer fall short and should be rejected by the Commission.

ii. The Company's argument that Staff's ROE is flawed due to incorrect inputs in Staff's cost of equity models is groundless.

The Company contends that Staff's cost of equity analysis is flawed because the inputs used in Staff's models were either inconsistent or flawed, and that Staff did not consider current market conditions or the impacts of recent legislation on its ROE analysis. (Doc No. 327, 3 TR 504-517.) The Company's arguments fall short. Staff will not address all the Company's arguments against Staff's cost of equity analysis. Rather, Staff will address a few specific arguments the Company made in its rebuttal, first, regarding Staff's DCF Analysis, second regarding Staff's CAPM, and third, regarding Staff's ECAPM analysis.

First, the Company argues that Staff's DCF analysis is inaccurate because the growth estimates used in its analysis are from sources that are redundant to its source. The Company also claims that Staff's use of a semi-annual compounding method when computing its DCF estimate marks a direct departure from how Staff performed its DCF analysis in the past. Those arguments are meritless.

Staff's use of outside analysts earning growth rates estimates have been an objective, neutral and standard measure of growth estimates used by most analysts in utility rate cases. Staff's sources, i.e. I/B/E/S, Value Line and Zack's are credible, experienced and industry wide sources of growth rate estimates. The Company's argument against use of all of the sources should be rejected. (Vol. 6, Tr 1729.) The

semi-annual compounding method used in Staff's DCF analysis has been a standard measure used in all the Company's rate cases dating back a decade or more. The Company's contention that Staff recently changed its methodology, as late as U-18124, is baseless. Staff has consistently used the semi-annual compounding methodology in its DCF model estimates and will continue to do so.

Second, the Company argues that Staff's CAPM analysis is flawed because Staff has not recognized that the Federal Reserve is currently suppressing interest rates thus anomalous market conditions affect the cost of equity models. The Company argues that due to the anomalous market conditions unconventional inputs into its CAPM is proper analysis.

Third, the Company also reiterates its disagreement to Staff's rejection of its ECAPM approach. (Doc. No. 333, Vol. 4, Tr 893-894.) The Company's arguments are meritless.

The Company's claim of anomalous market conditions and suppressed interest rates fall way short. Staff notes that the Federal Reserve raised interest rates three times in 2017, twice in 2018 and are poised to raise them again. (Vol. 6, Tr 1734.) Thus, the Fed is not artificially suppressing rates as the Company surmises but is managing interest rates and thus the economy as it sees fit based on market forces. The Company also argues that Staff's rejection of its ECAPM analysis lacks merit and is not supported by sound analysis. The Company's arguments are baseless.

Staff references Dr. Morin's 2006 publication, *New Regulatory Finance*, which Mr. Maddipati references in his testimony regarding the use of adjusted betas in the ECAPM analysis. Staff notes that its use of adjusted betas along with long-term Treasury Bond rates in its CAPM analysis renders the ECAPM adjustment unnecessary. (Vol. 6, Tr 1736.) To Staff's knowledge, the ECAPM methodology has never been approved by this Commission or any other state commission in a gas or electric utility rate proceeding. (Vol. 6, Tr 1805.) The Company's arguments in favor of its ECAPM approach and ROE estimates should be rejected by the Commission.

iii. Staff's ROE Recommendation Summary

Staff's 9.75% ROE recommendation is a reasonable ROE estimate for the Company in this rate case based on the Company's reduced risk as it relates to Michigan's unique utility-favorable legislation, i.e. PA 286 and 341. The Company's solid credit rating and considerable access to credit markets at very reasonable rates, its overearning of its ROE the past few years, and the Company's substantial risk reducing request for an investment recovery mechanism (IRM). With respect to the IRM, the Company is requesting the authority to surcharge its customers and thus collect substantial revenues for future project investments that will be determined by the Company. This request, if granted, in this case or a future rate case, would greatly reduce the Company's business and financial risk on a going forward basis. This lower risk calls for a more balanced ROE along the lines of Staff's recommendation. Therefore, for the reasons stated above, the Commission

should authorize a ROE of 9.75% and reject the Company's unreasonable and highly inflated 10.75% ROE recommendation.

V. Net Operating Income and Related Reporting Issues

At base, adjusted net operating income (NOI) is the difference between a company's operating revenues and operating expenses for the projected test year.

In re Detroit Edison's 2010–2011 Electric General Rate Case, MPSC Case No. U-16472, 10/20/2011 Order, p 41, Doc. No. 374.

A. Staff recommends total adjusted net operating income of \$647,855,000.

The Company rebuttal recommends a total adjusted NOI of \$633,973,000, while Staff recommends a \$647,855,000 total adjusted NOI. (Appendix C.)

Differences between the Staff's and the Company's total adjusted NOI are due to Staff adjustments to various Company revenue and expense projections as detailed below.

1. Staff recommends \$4,352,538,000 total operating revenues.

Consumers rebuttal projects that its total operating revenues will be \$4,351,500,000 in the projected test year, which is \$1.388 million less than Staff's projected total operating revenue of \$4,352,538,000. (Appendix C.) Staff's projected total operating revenue is greater than the Company's due to Staff's adjustment to sales revenue.

a. Staff recommends approving \$4,274,814,000 total sales revenue.

Consumers rebuttal projects that its total present sales revenue will be \$4,273,426,000 in the projected test year, which is \$1.388 million lower than Staff's \$4,274,814,000 projected total present sales revenue. (Appendix C.) The Company's present sales revenue is lower than the Staff's because it includes a correction to an error in the Company's proposed sales revenue for lighting customers. (Doc. No. 342, Vol. 6, Tr 2740-2741.) Staff does not dispute this correction.

i. Staff recommends a present revenue increase of \$3.4 million (reduced to \$1.388 million due to company concession).

Staff recommends an increase in present revenue of \$3.4 million, due to tax savings, resulting from the Tax Cuts and Jobs Act of 2017 (TCJA). Shortly following the Company's application, which was filed May 14, 2018, the Commission issued two orders in the Company's prior electric rate case, affecting base rates, the second increasing present revenue. The Commission also issued an order implementing a credit to reflect TCJA tax savings.

First, on June 11, 2018 the Commission issued an errata order in the Company's previous rate case MPSC Case No. U-18322. *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 6/11/2018 Order, Doc. No. 503. The errata order only affected base rates for primary customers.


Second, on June 28, 2018 the Commission issued a rehearing order in the same case that adjusted the total revenue requirement from the amount initially approved in its March 29, 2018 order. The result of this update is an increase in present revenue of \$3.4 M. (Doc. No. 344, Exhibit S-6, Schedule F-2.2, column D, line 36.) The increase in present revenue reduces the Company's revenue deficiency by the same amount. The Company agrees with Staff's adjustment to present revenues to reflect the two corrective orders. (Doc No. 334, Vol. 5, Tr 1581.) Staff recommends that the Commission approve its adjustments to present revenues as a result of the errata and rehearing orders from the Company's previous rate case.

Third, on July 24, 2018, the Commission issued MPSC Case No. U-20102, approving TCJA Credit A. (Doc No. 342, Vol. 6, Tr 2350.) Per the terms of the Order, the negative surcharge, Credit, A associated with the Company's base rates for electric service remains in effect, until base rates reflecting the current tax impacts of the TCJA on the Company's current federal income tax (FIT) expense, and revenue multiplier for its electric utility business are set in this electric rate case.

The overall effect on customer bills at the conclusion of the instant case includes both the approved revenue requirement coupled with the elimination of the TCJA Credit A amount of \$123.4 million, as determined in this case. The expiration of TCJA Credit A is not an adjustment to Staff's or the Company's case, but rather included to show that even if the Commission approves a revenue sufficiency, it may still result in an overall bill increase for customers.

The company conceded an amount related to the U-18322 errata and the update of street lighting billing determinants. Company witness Myers rebuttal testimony states that the company made an adjustment which was:

“[a] net increase in revenue of \$2,546,000 to reflect the impacts of the Case No. 7 U-18322 Errata Order, Rehearing Order, and the update of street lighting billing determinants. (Exhibit A-167 (HJM-70). Company witness Eugène M.J.A. Breuring discusses this in his rebuttal testimony.” 2 TR 354.

Staff continues to support a total \$3.4 million increase. With the company concession at brief, the remaining portion of the staff adjustment above and beyond the concession is \$1.388 million. 

b. Staff recommends \$25,491,000 total wholesale revenue.

The Company projected that it would receive \$25.491 million in wholesale revenue during the projected test year. (Appendix C.) Staff recommends the Commission adopt the Company’s projection.

c. Staff recommends \$52,233,000 total other electric revenue.

The Company projected that it would receive \$52,233,000 in total other electric revenue during the projected test year. (Appendix C.) Staff recommends the Commission adopt the Company’s projection.

B. Staff recommends approving \$3,713,517,000 total operating expenses, as further explained below.

Staff's recommended \$3,713,517,000 total operating expenses is \$12.494 million less than the Company's rebuttal projection of \$3,726,011,000. (Appendix C.) Staff breaks down this \$12.494 million difference here, by category, and explains the difference below:

Other O&M Expense	\$(13,507,000)
Depreciation and Amortization Expense	\$(2,679,000)
Real and Personal Property Tax	\$(719,000)
Other (or local) Tax	\$28,000
State Income Tax	\$925,000
Federal Income Tax	<u>\$3,458,000</u>
Total Adjustments to Operating Expenses	\$(12,494,000)

Staff takes no issue with the Company's recommended \$2,124,368,000 total power supply costs. Staff also takes no issue with the Company's \$30,775,000 projected total other general taxes.

1. Staff recommends approving \$580,634,000 total other Operation & Maintenance (O&M) expense.

Staff recommends total other O&M expense of \$580.634 million, which is \$13.507 million less than the Company projected \$594.141 million in its rebuttal filing. (Appendix C.) Staff agrees with the Company's projections for the following Other O&M Expenses: electric distribution, fossil & hydro generation, operation support, fleet, pension, defined company contribution plan, 401 (K) savings plan, active health care / insurance / long-term disability, retiree health care and life insurance, corporate, uncollectibles, injuries and damages, demand response other

O&M expense, customer payment program, and job work expense. Staff, however, has adjusted the following Other O&M Expense categories by the amounts listed (Appendix C):

Information Technology	\$(8,282,000)
Customer Experience	\$(768,000)
Customer Experience – Marketing & Strategy	\$(1,168,000)
Incentive Compensation	<u>\$(3,289,000)</u>
Total Adjustments to Other O&M Expense	\$(13,507,000)

a. Staff recommends reducing information technology O&M expense by \$8,282,000.

Staff recommends that the Commission disallow \$8.282 million of the Company’s projected information technology O&M expense. (Appendix C.) Staff witness Theresa McMillan-Sepkoski recommends that the ALJ and the Commission approve projected O&M expenses for Business Technology Solutions (BTS) of \$45,593,000, a reduction of \$8,282,000 from the Company’s application filing of \$53,875,000. Exhibit S-10 shows this difference.

Staff provided two reasons why the ALJ and the Commission should adopt Staff’s adjustment to BTS. First, Staff witness McMillan-Sepkoski testified that “the Commission has previously found that a 5-year historical average is a more reasonable and prudent approach to projecting BTS/IT expenses.” *In re Consumers Energy Company 2016-2017 General Natural Gas Rate Case*, 7/31/17 Order, MPSC Case No. U-18124, p 76, Doc. No. 239. This is because a historical average anchors BTS O&M expense projections in audited and verified actual expense experience,

which could result in a more reasonable and prudent approach to projecting this expense type.

In rebuttal, Company witness Hall testified that “A five-year average is not more accurate than specifically-stated cost projections that are based on known existing costs and plans”. (Doc. No. 326, Vol. 2, Tr 285.) But, Mr. Hall does agree that BTS expense is variable, stating “The magnitude of these costs can vary from project to project, based on each project’s requirements, and is the primary reason for the increase in IT O&M expense from 2013 through 2017.” (Vol. 2, Tr 286.)

Witness Hall also included a chart of Operations O&M Costs Compared to Capital Spend in his rebuttal testimony but neglects to include all BTS O&M costs. (Doc. No. 326, Vol 2, Tr 252.) If he had, the chart would show that the \$53,875,000 total actual BTS O&M expenses that the Company has projected for 2019, which is based off the actual O&M expense of 2017, is considerably higher than the O&M costs for 2015, and \$9,000,000 more than actual O&M expense in 2016. 2017 BTS actual O&M expenses was an anomaly when compared to 2016 and 2015 BTS actual O&M expense.

Second, Staff adjusted the origination expense. As Company witness Hall stated in his direct testimony:

Origination expenses are utilized during the concept phase of proposed IT projects. IT employees and contractors use this time to determine expected business objectives and outcomes, explore alternatives, perform a proof of concept, identify performance requirements, and to investigate the effectiveness of vendor products. The outcome of this work constitutes a rough order of magnitude for project costs weighed against the expected benefits to determine whether a proposed project

should be approved for development and implementation. [Doc. No. 326, Vol. 2, Tr 253-254.]

This category is highly speculative and contingent upon progressing forward as an actual project. The risk of these proposed projects should not be the burden of the ratepayer. The Company projected origination expenses of \$577,000. Staff recommends disallowing the origination portion of BTS Expense. The Commission found that origination expenses were not reasonable for the same reasons cited in the 7/13/17 Commission Order in *In re Consumers Energy Company 2016-2017 General Natural Gas Rate Case*, MPSC Case No. U-18124 at p 77 (Doc. No. 239).

The magnitude of variability coupled with speculation and risk is precisely why the ALJ and the Commission should adopt Staff's projection, which relies on a five-year average and removal of origination expense. Staff's recommendation protects the ratepayer from sporadic, unpredictable, and volatile expense projections by smoothing them for ratemaking.

b. Staff recommends reducing the Customer Experience O&M expense by \$768,000.

Staff recommends that the Commission disallow \$768,000 of the Company's projected customer experience O&M expense. (Appendix C.) The Company has failed to provide evidence to support that amount of the expense. Company witness Hubert Miller testified to an increase in Customer Payment Programs of \$1,168,400 from the historical year 2017 to the 2019 test year. In his direct testimony, he explained that \$400,000 of this increase was due to the elimination of the \$1.75 fee customers used to be charged for using a credit card at a third-party payment

center. (Doc. No. 334, Vol. 5 Tr 1792.) Staff recommends that the Commission accept this justification for the increased \$400,000 but recommends a disallowance of \$768,400, the remaining test year increase for which the Company provided no justification.

In rebuttal testimony, Company witness Miller argues that the remaining increase is due to the expected growth the Company expects to see in credit card payments overall. (Doc No. 334, Vol. 5, Tr 1822.) He testifies that the Company expects to see credit card usage increase at over 25% in the next year due to the increase from 15% in 2017 to over 20% in 2018.

In her direct testimony, Staff witness Lauren Fromm states that the justification for the increase in O&M expense in Hubert Miller's testimony of \$400,000 is contradictory to what is shown in Company Exhibit A-106 HWM-2, page 2 line 12, and therefore adjusted the O&M amount to show only what was justified in testimony. (Doc No. 342, Vol. 6 Tr 2424.) This explanation of an increase in credit card usage is evidence that is supplemental to what was supplied in its application, discovery and direct testimony.

The statements are not supported, moreover, by any evidence that shows how the \$768,000, which previously had no explanation, is calculated from an expected increase from 15% to 25% in customer credit card payments. Due to the lack of record evidence required to support the \$768,000 O&M increase, Staff recommends the Commission not allow the Company to recover that purported expense.

Staff recommends that the Commission disallow \$1.168 million of the Company's projected customer experience—marketing strategy O&M expense. (Appendix C.) Company witness Hubert Miller testified to an increase in Customer Payment Programs of \$1,168,400 from the historical year 2017 to the 2019 test year. In his direct testimony, he explained that \$400,000 of this increase was due to the elimination of the \$1.75 fee customers used to be charged for using a credit card at a third-party payment center. (Doc. No. 334, Vol. 5 Tr 1792.) Staff recommends that the Commission accept this justification for the increased \$400,000. Staff also recommends a disallowance of \$768,400, the remaining test year increase for which the Company provided no justification.

- c. The Commission should disallow the \$1,168,000 (formerly stated as \$3,403,000 in the application) associated with the Company's projected marketing expenses for the Summer On-Peak rate.**

In its, March 29, 2018 Order in Case No. U-18322, the Commission required that the Company “eliminate the inverted block rate and replace it with a summer, on-peak, non-capacity rate for residential customers.” *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, Doc. No. 489. The Company is projecting a test year expense of \$10,116,000 that is associated with promoting the benefits of the Residential Summer On-Peak rate and implementing a successful customer transition plan. (Doc. No. 334, Vol 5, Tr 1808.) Staff recommends that the Commission disallow the now \$1.168 (formerly \$3.403 million because the company conceded \$2.235 in rebuttal) that is associated

with marketing costs that include specifically Research & Message Targeting, User Segmentation & Analytics, Marketing & Communications and Strategic Communication costs. These categories are what the Company has identified to be necessary to conduct market research on how customers preferred to be communicated with regarding the Summer On-Peak rate, the identification of specific customer groups to tailor communications, the development of a strategy based on market research and analytics to educate the customers, and the use of paid media channels to inform and educate the Company's residential customer base. (Doc No. 342, Vol. 6 Tr 2425.)

Staff recommends the projected expenses associated with these initiatives be disallowed because they are unnecessary. The Company argues that it is important to promote the benefits of the Residential Summer On-Peak rate and assure that customers are being communicated with in a way that is desirable to them in whichever customer segmentation group they may fall. Staff disagrees with this position, as it was not the intention of the Summer On-Peak rate to illicit a response from customers. Regardless of whether or not a customer understands the benefits of being on the Summer On-Peak rate, the rate is still doing what it was intended to do, and that is more accurately reflect the costs that residential customers cause on the system in the summer months than the previous inverted block rate. (Doc. No. 342, Vol. 6 Tr 2425.) The Summer On-Peak rate is not to be mistaken as a demand respond rate, which is intended to change the customer's behavior.

The Company uses its history with the Smart Energy Program as additional justification for taking the extensive steps they are planning for the Summer On-Peak rate. Company witness Miller draws on the Company's successful implementation of the smart meter rollout that he testifies was due to the Company's invested time and resources in developing effective communication plans and processes based on market research, testing of best practices and customer feedback. (Doc. No. 334, 5 Tr 1809.) These two situations are inherently different. While the Smart Energy Program represented an elective new technology that brought up customer concerns regarding privacy, health, safety, and security, the Summer On-Peak rate is simply a new rate structure that the Commission has ordered the Company to implement to better reflect the costs the residential customer class creates.

Staff also finds the extensive marketing efforts the Company has planned unnecessary because customers have been conditioned to seeing changes in their rates for the last three years, as the Commission has approved the Company's request for recovery resulting in rate increases on an annual basis. The Company does not do any of the efforts they are planning for the Summer On-Peak rate when a new rate order is issued, and Staff does not find it prudent or relevant for the Summer On-Peak rate implementation.

In its rebuttal testimony the Company argues that customers will not simply see this change as a price change. It holds this position because it has already reached out to its customers through six focus groups to evaluate how the new rate

is perceived and reports that customers questioned the trustworthiness of the Company when no explanation was given for the change in rate structure (Doc No. 334, 5 Tr 1823.) When the Company provided the customers with details on the new rate most indicated they understood the reason for the change were amenable to the new structure. (Doc. No. 0334; 5 Tr 1824.) The Company argues that segmentation of customers and data analytics is important to tailor communications to certain customer groups. While Staff understands that communication efforts will make the transition a more favorable experience for the company and its customers, it does not find the associated cost to represent prudent spending. The nature of the change remains unaffected. It is simply to better reflect the costs that residential customers are causing to the system.

In addition to the requested O&M expense increase due to the marketing the Company would like to do for the program, it is also requesting to increase its O&M expense due to increased staffing needs in both the Customer Billing and Customer Contact Center departments of the Customer Operations division. The Company states that the implementation of the Summer On-Peak rate will cause an increase of live agent call volume in the amount of 350,000 calls as well as an increase of additional invoice reviews in the amount of 300,000 annually. The Company states that this requires an additional \$4.3 million in O&M expense in order to hire 70 new full-time customer service representatives (CSRs) and 27 new full-time billing specialists. (Doc No. 0342; 6 Tr 2426.) Staff has concerns with this request, given that the increase in workload for both CSRs and billing specialists will only exist

over the three-month period that the new rate is in effect. The Company claimed that due to the 8 months of time it will be investing in pre-employment screening and post-employment training, the use of seasonal or temporary employees is not feasible. However, in addition to this increase in call volume and invoice reviews taking place for only one quarter of the year, the Company only expects these volumes to sustain for the first few years after implementation of the new rate.

(Doc. No. 344, Exhibit S-9.3 p 9.) While Staff does not have a recommendation to make for proposed staffing expenses due to the uncertain nature of the expenses and understanding that the Company will need to hire additional staff prior to the projected increase in call volume due to the extensive on-boarding process, Staff finds it important to outline its concerns for the Commission to consider.

Though the Company has brought up several arguments for why the summer on-peak marketing costs should be allowed, Staff does not find any of these explanations compelling enough to warrant the requested spending. The Summer On-Peak rate still functions as it should whether customers are willing to accept the rate or not. The rate is not intended to influence the usage patterns of customers, and therefore does not need customer buy-in to be successful. Staff finds the Company's projected expenses for the marketing of the Summer On-Peak rate unnecessary and therefore believes the Commission should disallow the now \$1.168 (formerly \$3.403 because the Company conceded \$2.235) O&M expense.

d. Staff recommends reducing Consumers' incentive compensation O&M expense by \$3,289,000.

Staff recommends that the Commission disallow \$3.289 million of the Company's projected employee incentive compensation O&M expense. (Appendix C.) Incentive Compensation Expense is a portion of an employee's pay that is dependent upon achieving target levels of performance measures. It is also known as the Employee Incentive Compensation Plan, or EICP. The Company requested \$5,029,000 in projected costs attributable to EICP. (Exhibit A-13, Doc. No. 328 at 58, Schedule C5, Line 18.) However, Staff recommends \$1,740,000 in projected EICP costs, a \$3,289,000 reduction from the Company's application. (Doc. No. 344 Exhibit S-3, at 8 Schedule C5, Line 14.)

The EICP provides eligible employees the opportunity to earn EICP for reaching certain goals. Those goals, historically, have been related either to financial or non-financial performance measures. In this case, the Company seeks recovery of EICP expense related to both financial and non-financial performance measures. For 2018, there are nine specific operational performance measures and two measures related to being financially healthy (Doc. No. 334, Vol. 5, Tr 2079, at 713.) In Staff's opinion, the prior statement "measures related to being financially healthy" can be interpreted as "financial measures used in determining the financial portion of the EICP benefits". The Company provided Staff with the operational performance and financial performance areas that the EICP focuses on. (Exhibit A-70, Doc. No. 331 at 310.)

Historically, the Commission has found that incentive compensation plans tied to Company earnings and cash flow were financial considerations that largely benefited shareholders and should not be paid by ratepayers. Second, the Commission has repeatedly found that utilities did not sufficiently quantify the benefits to the ratepayers of employee incentive compensation plans that are tied to financial metrics and demonstrate that the benefits to customers of such plans outweigh the costs. (Doc. No. 342 Vol. 6, Tr 2464.) The following table is a quick view of the Commission’s past handling of the EICP expenses as it relates to financial performance measures.

FIGURE 1: History of Consumers Energy's Request for Incentive Compensation Expenses in Rates

Case No.	Order Date	Description	Allowed in Rates?	
			<u>Financial Metrics</u>	<u>Non-Financial</u>
U-14347	12/22/05	Consumers Energy Company/Electric Order dated 12/22/2005, Page 34	NO	NO
U-14547	11/21/06	Consumers Energy Company/Gas Order Dated 11/21/2006, Page 44	NO	NO
U-15245	6/10/08	Consumers Energy Company/Electric Order dated 06/10/2008	NO	NO
U-15645	11/2/09	Consumers Energy Company/Electric Order dated 11/02/2009	NO	NO
U-16855	6/7/12	Consumers Energy Company/ Gas Settlement dated 06/07/12	N/A	N/A

U-17197	12/6/13	Consumers Energy Company/Gas Application Withdrawn	N/A	N/A
U-17735	11/19/15	Consumers Energy Company/Electric Order dated 11/19/2015	NO	YES
U-17643	1/13/15	Consumers Energy Company/Gas Settlement Dated 01/13/2015	N/A	N/A
U-17882	4/14/16	Consumers Energy Company/Gas Settlement Dated 04/14/2016	N/A	N/A
U-18124	7/31/17	Consumers Energy Company/Gas Order Dated 07/31/2017	NO	YES
U-18322	3/29/18	Consumers Energy Company/Electric Order Dated 03/29/2017	NO	YES
U-18424	8/28/18	Consumers Energy Company/Gas Settlement Dated 08/28/18	N/A	N/A

In summary, non-financial metrics are the only metrics that the Commission has approved, and there is nothing about the current case that should change the result in this case. The ALJ and the Commission should only allow the portion of the EICP expenses that relate to the achievement of non-financial goals by eligible employees, which is \$1,740,000. (Doc. No. 344, Exhibit S-8.0, Doc. No. 344 at 110.) The remaining amount of EICP expenses, or \$3,289,000, relating to financial goals should be disallowed.

2. Staff recommends approving a \$650,538,000 total depreciation and amortization expense.

In its rebuttal filing, Consumers projected that its total depreciation and amortization expense would be \$653.217 million. Staff decreased this projection by \$2.679 million for a total depreciation and amortization expense of \$650.538 million. (Appendix C.) The difference stems from Staff's capital expenditure adjustments; fewer capital expenditures reduced the total being depreciated and, thus, the depreciation expense. (See Section III.B and Appendix E.)

3. Staff recommends approving a \$168,302,000 total real and personal property tax expense.

Consumers rebuttal projected a \$169.021 million total real and personal property tax, which is \$719 thousand million more than Staff's \$168.302 million projection. (Appendix C.) Again, the difference stems from Staff's capital expenditure adjustments, which reduce real and personal property taxes. (See Section III.B and Appendix E.)

4. Staff recommends \$1,347,000 total other or local income tax expense.

Consumers projected a total other or local income tax expense of \$1,320,000, which is \$28 thousand less than Staff's projection of \$1,347,000. (Appendix C.) Staff's adjustments to the Company's projected revenues and expenses led to the difference between Staff's and the Company's other or local income tax expense.

5. Staff recommends approving \$40,511,000 total state income tax expense.

Staff recommends \$40.511 million total state income tax expense, which is \$925 thousand more than the Company's projection in its rebuttal filing. (Appendix C.) Like the other or local income tax expense, the difference between Staff's and the Company's state income tax expense is the result of various Staff adjustments to the Company's projected revenues and expenses.

6. Staff recommends \$117,041,000 total federal income tax (FIT) expense.

Staff recommends total federal income tax (FIT) expense of \$117.041 million, which is \$3.458 million more than the Company's projection in its rebuttal filing. (Appendix C.) Again, Staff's adjustments to the Company's projected revenues and expenses are responsible for the difference.

7. The Company should continue to supply an updated business case for its Smart Energy Program.

The Company completed installations of its AMI meters in 2017 and requests the Commission conclude the Company's obligation to continue supporting the business case because it does not expect future updates will be necessary. (Doc. No. 333, Vol. 4, Tr 974.) The Attorney General disagrees with this request in its direct testimony stating that the business case is a comprehensive analysis of costs and benefits to show that the benefits of the AMI program will surpass the costs that the Commission has approved over the life of the meters. (Doc. No. 342, Vol. 6, Tr 2814.) The Attorney General further argues that the point in which the cumulative

benefits passed on to customers exceeds the cumulative revenue requirement billed to the customers has not yet been reached, therefore the Company should still be held accountable to ensure that the program fulfills its goal of being a net benefit to customers. (Doc. No. 342, Vol. 6, Tr 2815.)

The Company argues that the lag between benefits and investments is natural and logical and because operational improvements have been implemented the Company has fulfilled its obligation. (Doc. No. 333, Vol 4 Tr 991.) Company witness Lincoln Warriner further argues that there are additional potential benefits associated with the Company's investment in AMI meters that have not been included in its cost/benefit analysis such as conservation voltage reduction. (Doc No. 0333; 4 Tr 992.)

Staff agrees with the Attorney General. The Company has testified to a net present value (NPV) of \$93.9 million (Exhibit A-116 (LDW-3) p 5.) However, as the Attorney General points out, cumulative benefits have not yet exceeded cumulative costs of the program. The Smart Energy Program is also not just the installation of the AMI meters, but the customer programs it enables as well. For example, the Company includes benefits from demand response and Load Management conserved energy as well as AC Load Control and demand response avoided generation. Regardless of the Company testimony that argues these programs have already been implemented, the predicted benefits are based upon participation rate estimates as well as achieved savings per customer estimates that have yet to materialize fully. The Commission should order the Company to continue supplying

an updated cost benefit analysis so that the Commission, Staff, and Intervenors can continue to monitor the successfulness of the program, not only for the sake of seeing the benefits materialize, but as a tool to gauge the Company's expected performance on future programs that rely heavily on future projected benefits.

C. Staff recommends approving \$8,834,000 total allowance for funds used during construction (AFUDC).

Consumers included \$8.834 million in total AFUDC in its initial filing. Staff agrees that this is the correct amount.

VI. Energy Waste Reduction and Demand Response

A. Energy Waste Reduction

In its last electric general rate case, the MPSC directed the Company to support its forecasting methodology and calculations and more specifically, how the Company has addressed the impacts of energy waste reduction (EWR) programs on the future load forecasts. *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*, MPSC Case No. U-18322, 03/29/2018 Order, p 50. In the same Order, the Commission also directed Staff to engage with stakeholders on the topic of EWR and sales forecasting. Staff met with the Company twice prior to the filing of this rate case to learn more about these effects. As testified by Staff witness Karen Gould, (Doc No. 342, Vol. 6, Tr 2450-2455), Staff is aware there are multiple excepted ways to account for the effects of utility funded EWR programs in forecasting. Through these meetings and subsequent audit findings, Staff believes,

at this time, the forecast methodology used by the Company seems reasonable, under the present circumstances. Further, Staff anticipates future active conversations with the Company and other Michigan utilities regarding EWR effects on sales forecasting within the EWR Collaborative.

B. Staff recommends the Commission approve the Company's expenditures for demand response programs.

Staff recommends the Commission approve the Company's projected expenditures that support residential and C&I demand response programs. The Company plans its C&I program to achieve 70 MW of demand savings by the end of 2018 and 120 MW of demand savings by the end of 2019. (Doc. No. 342, Vol. 6, Tr 2562.) To facilitate this demand savings, it plans to invest 0.666 million for the 12 months ending December 31, 2018 and an additional \$0.438 million the 12 months ending December 31, 2019 in capital. Additionally, the Company is requesting \$4.355 million for the 12 months ending December 31, 2018 and \$5.755 million for the 12 months ending December 31, 2019 in O&M expenses for this program. (Vol. 6, Tr 2562.)

Likewise, the Company plans its residential A/C cycling program and residential dynamic pricing programs to achieve demand savings. The Company projects its A/C cycling program to achieve 31.7 MW of demand savings by the end of 2018 and 50 MW of demand savings by the end of 2019. (Doc. No. 342, Vol. 6, Tr 2564.) To achieve the projected savings, the Company plans to spend \$6.138 in capital for the 12 months ending December 31, 2018 and \$8.436 million for the 12

months ending December 31, 2019 with an additional \$3.390 million for the 12 months ending December 31, 2018 and \$3.437 million for the 12 months ending December 31, 2019 in O&M expenses. (Vol. 6, Tr 2564.) The Company projects its residential dynamic pricing programs to achieve a total demand reduction of 14MW (14.4 ZRCs) by year-end 2018 and 17.1 MW (17.7 ZRCs) by year-end 2019. (Vol. 6, Tr 2565.) To achieve the projected savings, the Company plans to spend \$10.068 million the 12 months ending 12/31/2019 and an additional \$1.820 million in 2018 and \$1.074 million in 2019 for O&M expenses. (Doc. No. 342, Vol. 6, Tr 2566.) MEC-NRDC-SC witness Jester supports the Company's demand response programs. (Vol. 6, Tr 2659). No other parties rebutted Staff's recommendation. Staff recommends that its proposal be adopted.

- 1. Staff recommends minor revisions to the Company's demand response plan be proposed and evaluated in the Company's demand response (DR) reconciliation cases.**

Staff recommends that any modifications to the Company's demand response (DR) plan that it wishes to implement between approved integrated resource plan (IRP) cases be proposed and evaluated in a DR reconciliation case. The Commission has provided a demand response framework in Case No. U-18369, which Staff describes in testimony. (Vol. 6, Tr 2569.) Staff's recommendation that the evaluation of detailed demand response program characteristics and expected costs that may be adjusted slightly from year-to-year is best done in a focused demand response case because it is the most appropriate case to review and evaluate specific programs in detail on an annual basis. Staff supports the major revisions and long-

term expansion of demand response be evaluated in IRP cases as the Commission has directed in its September 15, 2017 order. (Doc. No. 342, Vol. 6, Tr 2568). No other party rebutted Staff's recommendation. Therefore, Staff recommends that its recommendation be adopted.

VII. Cost of Service and Rate Design

After calculating the Company's rate base, its ROE, and its adjusted net operating income, Staff calculated the Company's revenue requirement. Staff used this revenue requirement to allocate costs and design rates.

A. The Commission should continue to approve the 4CP 75/0/25 method of allocating production costs.

The Company proposed changing the production allocator from 4CP 75/0/25 (4CP 75/25) to 4CP Average and Excess (4CP A&E), claiming their proposal better reflects cost-causation and the impact of load factor. (Doc. No. 334, Vol. 5, Tr 1655, 1657.) However, according to the NARUC Electric Cost of Service Manual (NARUC Manual), the Company's proposed method results in an allocation functionally identical to a CP method, which has been repeatedly rejected by the Commission. 6 TR 2432. As noted by Staff witness Susan E. Goepf, "the complicated A&E formula doesn't do any more to reflect energy in the cost allocation than if a single CP demand allocator was utilized". (Doc. No. 342, Vol. 6, Tr 2434.) The Company claims that Staff relies on the NARUC Manual's NCP recommendation, cites the NARUC Manual's disclaimer on recommendations, and claims that changes in markets and generation technologies have led to other jurisdictions using 4CP A&E.

(Vol. 5, Tr 1676-1677.) First, Staff did not rely on a recommendation from the NARUC Manual to propose NCP A&E. Staff was merely pointing out a factual statement contained in the NARUC Manual that 4CP A&E is equivalent to a pure CP method. The Company did not show this not to be the case, nor deny that it was. Second, the disclaimer states that analysis of allocation methods should be based on the assessment of objectives. If the Company's objective was to propose a pure CP method clothed in the arguments associated with the A&E method (which relies on NCP, not 4CP), then it succeeded. Third, the evidence relied on in other jurisdictions when approving the 4CP A&E method are not on the record, so the Company's claim on said reasons is purely speculative. The Company also identifies issues with the NCP A&E methods (e.g. the A&E method). Staff did not support the NCP A&E method (e.g., the A&E method) and therefore feels no need to mount a defense of it here. The point of Staff's argument was that the arguments in favor of the NCP A&E method (e.g. the A&E method) are not applicable to the Company's proposed method, as the Company's method is effectively a pure CP method, which has been repeatedly rejected by the Commission. The Company also argues that the 4CP A&E method better reflects the impacts of load factor, claiming that those with higher peaks should be charged more as it costs more to serve load on-peak. (Doc. No. 334, Vol. 5, Tr 1658.) Staff believes the statement to be disingenuous. What costs more to serve on-peak is energy, and the Company properly utilizes energy allocators split into time periods for which costs are different to take this into account. What 4CP A&E, as well as a pure CP allocator,

fails to acknowledge is the fact that the base load plants have higher non-energy costs, which are the costs the production allocator allocates. *In re on the Commission's own motion to implement PA 169 of 2014, Consumers Energy Company*, 6/30/2015 Order, MPSC Case No. U-17688, pp 9, 15, Doc. No. 159. As the Commission ordered, quoting Staff's reply brief, in Case No. 17688, and was re-quoted by Staff witness Goepp in her testimony in this case:

It is important to remember that we are not allocating capacity, but the cost of that capacity. This is relevant because costs vary depending on the type of plant selected to provide an increment of capacity in the most cost-effective way—given information about the number of hours the plant is expected to run (i.e., energy) throughout the year. It is, therefore, inappropriate to ignore the cost differentials between capacity types and allocate based purely on capacity. [6/30/2015 Order, MPSC Case No. U-17688, p 15, Doc. No. 159, quoting Staff's reply brief, p 12, as quoted by Goepp in Doc. No. 342, Vol. 6 Tr 2439.]

Staff recommends maintaining the 4CP 75/25 allocator. 4CP 75/25 properly recognizes how the non-energy costs of production are caused by the interaction of demand and energy (e.g., load factor). (Doc. No. 342, Vol. 6, Tr 2433.) The Commission has approved this method for this and other reasons consistently over recent history.⁶ As noted by Staff, the logic previously used is just as applicable now, and the Company has not provided compelling evidence for a change. (Vol. 6, Tr 2439.)

To determine if the 25% is still reasonable, Staff conducted an analysis of the proportion of load that should be considered baseload with the costs of the plants that serve that load. The results showed that 25% is still reasonable. (Vol. 6, Tr

⁶ See order quotes. (Doc No. 342, Vol. 6 Tr 2435, 2437-2439.)

2437.) The Company takes issue with Staff's analysis, claiming that, as coal plants do not serve 100% of baseload, then only minimum generation should be considered as serving baseload. (Doc. No. 334 Vol. 5, Tr 1679.) The Company also claims that baseload generation will cease to exist. (Vol. 5, Tr 1682.) These arguments are *prima facie* illogical. While it is true that the plants used to serve baseload are changing, that does not eliminate the concept of baseload. The Company's arguments should be rejected as fallacious. A plant serving less than its maximum does not make it no longer baseload-serving. The potential reasons for low output are numerous, and do not change the fact that the plants serve baseload. The Company then proposes to use its *extremely* flawed analysis to reset the energy portion of the current allocator. (Doc. No. 334, Vol. 5, Tr 1682.) As Staff made clear, the result of such a calculation were not to be controlling, only a check on the sanity of the 25%. (Doc. No. 342, Vol. 6, Tr 2437.)

For the reasons above, the Company proposed production allocator should be resoundingly rejected, and Staff's proposal to continue using the 4CP 75/25 allocator should be approved.

B. The Commission should continue to approve the calculation of load profiles as a three-year average.

The Company proposes to change to using a five-year average of historical load profiles rather than a three-year average to calculate average test year load profiles, claiming that this change removes outliers and provides less weight to each year. (Doc No. 334, Vol. 5, Tr 1662.) Staff opposes this change, as it introduces the

hotter year of 2012 into the data, providing inappropriate weight to hotter years. (Vol. 6, Tr 2439.) Staff showed that the three-year average is closer to the 15-year average, generally used as the normal weather period, than either the four-or five-year averages. (Doc. No. 334, Vol. 5, Tr 2440.) Staff also argues that maintaining a consistent approach has value, especially as rate cases are filed near annually. *Id.* Concentrating on the result of the calculation in any given year and changing the method used based on that result results in undesirable inconsistency and a concentration on what the Company wants and what the data show. The Company introduces a new three-year average updated to include 2017 on rebuttal, claiming the results are close enough to the 15-year average to merit a change. (Doc No. 334, Vol. 5, Tr 1685-1686.) Staff recommends maintaining the three-year average based on the Company's initial filing, as Staff's initially proposed three-year average more closely align with the 15-year normal. For these reasons, Staff's proposal to maintain the three-year average should be approved.

C. The Commission should approve the Company's requested update to average meter equipment costs.

The Company proposed to update the meter equipment costs used to calculate allocators in the COSS, as AMI rollout is effectively complete. (Doc No. 334, Vol. 5, Tr 1669-1670.) Staff supports this change. (Doc. No. 342, Vol. 6, Tr 2441.) Therefore, this change should be approved.

D. The Commission should not require the Company to file future COSSs with allocators different from current for demand-related distribution cost allocation.

MEC/NRDC/SC/EC/EIBC witness Douglas Jester recommends that the Commission require future distribution allocations to be based on load-weighted energy usage, basing said recommendation on quotes from James Bonbright and asserted “engineering principles”. (Vol. 6, Tr 2618-2619.) The evidence presented by MEC/NRDC/SC/EC/EIBC witness Jester is insufficient to justify this proposal, particularly in light of the NARUC Manual’s guidance on the issue. (Vol. 6, Tr 2443-2445.)

E. Staff recommends a present revenue increase of \$3.4 million.

Staff recommends an increase in present revenue of \$3.4 million, due to tax savings, resulting from the Tax Cuts and Jobs Act of 2017 (TCJA). Shortly following the Company’s application, which was filed May 14, 2018, the Commission issued two orders in the Company’s prior electric rate case, affecting base rates, the second increasing present revenue. The Commission also issued an order implementing a credit to reflect TCJA tax savings.

First, on June 11, 2018 the Commission issued an errata order in the Company’s previous rate case MPSC Case No. U-18322. *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 6/11/2018 Order, Doc. No. 503. The errata order only affected base rates for primary customers.

Second, on June 28, 2018 the Commission issued a rehearing order in the same case that adjusted the total revenue requirement from the amount initially

approved in its March 29, 2018 order. The result of this update is an increase in present revenue of \$3.4 M. (Doc. No. 344, Exhibit S-6, Schedule F-2.2, column D, line 36.) The increase in present revenue reduces the Company's revenue deficiency by the same amount. The Company agrees with Staff's adjustment to present revenues to reflect the two corrective orders. (Doc No. 334, Vol. 5, Tr 1581.) Staff recommends that the Commission approve its adjustments to present revenues as a result of the errata and rehearing orders from the Company's previous rate case.

Third, on July 24, 2018, the Commission issued MPSC Case No. U-20102, approving TCJA Credit A. (Doc No. 342, Vol. 6, Tr 2350.) Per the terms of the Order, the negative surcharge, Credit, A associated with the Company's base rates for electric service remains in effect, until base rates reflecting the current tax impacts of the TCJA on the Company's current federal income tax (FIT) expense, and revenue multiplier for its electric utility business are set in this electric rate case.

The overall effect on customer bills at the conclusion of the instant case includes both the approved revenue requirement coupled with the elimination of the TCJA Credit A amount of \$123.4 million, as determined in this case. The expiration of TCJA Credit A is not an adjustment to Staff's or the Company's case, but rather included to show that even if the Commission approves a revenue sufficiency, it may still result in an overall bill increase for customers.

F. Residential design categories correlate to their purpose.

1. Staff recommends that the Commission approve the Company's updated plan to transition residential customers to the new summer on-peak rate.

In the Company's previous rate case the Commission required the Company to eliminate the inverted block rate for standard residential service and migrate customers to a new standard residential rate design that included an on-peak summer pricing component. (Doc No. 334, Vol. 5, Tr 1565.) In its initial filing the Company proposed to gradually transition customers from standard residential service Rate RS to the new summer on-peak rate over 12 to 16 months. (Doc No. 326, Vol. 2, Tr 277-278.)

The plans included in the Company's initial filing to lack sufficient detail and Staff theorized that the short period between the final order in the Company's previous case and the filing of the instant case provided insufficient time for the Company to develop a complete transition plan. (Doc No. 342, Vol 6, TR 2352.) Through audit in this case, the Company provided Staff with an updated transition plan that includes a substantial piloting phase in 2019 followed by the complete transition of customers on January 1, 2020. (Doc. No. 344, Exhibit S-17.) The updated transition plan would result in a \$2,235,000 reduction in test year O&M compared to the Company's initial filing. (Doc No. 334, Vol. 5, Tr 1826.) Staff recommends that the Commission approve the Company's updated plan to transition customers to the new summer on-peak rate, as well as the associated O&M adjustment.

The AG recommends that the Commission "reject the Company's proposal to transfer customers from the RS rate schedule to the new Residential Service

Summer On-Peak and make this new rate optional by informing customers of the benefits of the new rate and any potential drawbacks.” (Doc. No. 342, Vol. 6 Tr 2879-2880.) However, the Company’s proposal is in direct response to the Commission’s order. The Commission has previously addressed the purpose of the summer on-peak rate:

As discussed above, the Commission’s primary objective in eliminating the inverted block rate design, and replacing it with summer on-peak and off-peak rates, is to adjust the rate design to one that more accurately reflects cost-causation. Prior to the deployment of AMI, total monthly usage was the only available proxy for assessing customers for on-peak usage. [*In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, pp 105-106, Doc. No. 489.]

The proposed summer on-peak rate is not a demand response rate because its primary goal is not to change behavior. Rather, it is the result of the technology that allows the Company to bill using a cost-based methodology.

The AG’s recommendation should be rejected because the proposed summer on-peak rate is the Commission-approved method for recovering costs from standard-service residential customers, and demand response is not the primary purpose:

Now, with interval data made available by advanced metering systems, the [C]ompany can far more accurately bill customers in accordance with cost-causation principals. While customers may make some adjustments to shift energy usage from on-peak to off-peak hours, the primary purpose is not to further DR efforts. As noted, customers who want to do more may enroll in a voluntary program. [*In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, pp 106, Doc. No. 489

Staff concurs with the Commission's reasoning, noting that there are no facts to change conclusions, and recommends that the Commission and ALJ approve the Company's proposed summer on-peak residential rate design.

- a. Staff recommends the Commission approve its proposed transitional rate RS for customers not yet taking service on the summer on-peak rate.**

Due to the elongated timeline for implementation of the new rate most customers will remain on Rate RS into the test year. Staff proposes a transitional Rate RS that would retain the current inverted block structure. AMI opt-out customers and those who have not yet been transitioned to the new summer on-peak rate would remain on the transitional Rate RS until implementation is complete in 2020, after which AMI opt-out customers would remain on the Company's proposed, non-transitional Rate RS. (Doc No. 342, Vol. 6, Tr 2353.) The Company concurs with Staff on implementing the updated transition plan and associated transitional Rate RS. (Doc No. 334, Vol. 5, Tr 1581.)

- b. Staff recommends that the Commission require the Company to implement shadow billing before or during the test year of its next general rate case.**

Staff recommends that the Commission require shadow billing. Shadow billing is the act of showing a customer their monthly bill on one or more different rate options using the customer's actual usage so that the customer can see how those rate options would affect their bill. For example, a customer on standard residential Rate RS may use the Company's website to view what the bill would be

like, if the customer had been on the residential time-of-day Rate RT. In the Company's previous rate case Staff advocated for the use of shadow billing, and the Commission found it reasonable for the Company to continue to investigate its future use. *In re Consumers Energy Co 2017-2018 Electric General Rate Case*, MPSC Case No. U-18322, 03/29/2018 Order, pp 77-78, Doc. No. 489. Staff continues to favor shadow billing in the instant case. (Doc No. 342, Vol. 6, TR 2572.) The Commission has been supportive of shadow billing and a trial period in the Company's most recent rate, Case No. U-18322. (Vol. 6, Tr 2572.)

The Company agrees with Staff that shadow billing is an important educational tool for customers, and the Company plans to incorporate shadow billing in the future. (Doc No. 334, Vol. 5, Tr 1832.) Staff continues to recommend the use of either a trial period or shadow billing or other reasonable proxy for shadow billing that leverages the use of a customer's own AMI data to determine how new rates could impact their electric bill if usage patterns remain unchanged. (Vol. 6, Tr 2572-2573.) In testimony, Company witness Miller indicates the Company is still investigating tools such as shadow billing to help increase customer understanding of different rate options. (Vol. 5, Tr 1831). In rebuttal testimony, witness Miller indicates that the Company agrees with Staff that shadow billing is an important component of educating and information customers, therefore the Company plans to replace its existing IWP platform with one that includes shadow billing capabilities. (Vol. 5, Tr 1832.) No parties filed rebuttal to

Staff's recommendation. For these reasons, the Commission should require the Company to implement shadow billing.

G. Staff recommends that the commission approve Staff's proposed Critical Peak Pricing (CPP) provision.

Staff proposes that the Company implement a CPP provision applicable to the standard residential summer on-peak rate. The CPP provision is a voluntary (or opt-in) demand response rate that consists of a high critical peak price for critical event days and a discounted price for all summer off-peak hours. Staff's proposal is for the CPP provision's implementation to follow the same timeline as proposed by the Company for its proposed universal peak rewards provision. That is, following the pilot phase for the summer on-peak rate in 2019, the CPP provision would be available to all customers with an AMI meter beginning in 2020. The on- and off-peak hours for the CPP provision would conform to the Company's proposed hours for the summer on-peak rate. However, during critical event days the on-peak energy price would be \$0.95 cents per kWh instead of the standard \$0.140806. (Doc No. 342, Vol. 6, Tr 2356.) Critical events are called by the Company during times of high prices or stress on the system, require customer notification the day before, and are limited to 14 events per summer. (Vol. 6, Tr 2360-2361.) Under the CPP provision all off-peak summer hour prices are discounted by 50%. (Vol. 6, Tr 2357.) All winter and non-critical summer on-peak hourly prices would match the standard summer on-peak rate. Finally, customers on the CPP provision would also

be allowed to enroll in the Company's residential air conditioner cycling program. (Vol. 6, Tr 2359.)

The CPP provision offers a simplified dynamic pricing demand response program for customers, because the rate matches the existing on-and off-peak hour schedule and is discounted based on a percent rather than specific cents per kWh. Customers can more easily comprehend the effects of a rate that is marketed as "half-off" than "4 cents per kilowatt hour off," because customers rarely know the specific price of the standard rate. (Vol. 6, Tr 2357.) In designing the universal peak reward provision, the Company relied on a consultant's report by The Cadmus Group titled, *Peak Time of Use Pricing Options Program Annual Evaluation Report*. *Id.* Using the results of the same report, Staff found that customers are more concerned with bill savings rather than the price savings between rates, which supports the proposed CPP provision's percent discount method. (Doc No. 342, Vol. 6, Tr 2358.) Staff's proposed CPP provision acts as a two-part DR resource, because critical events can be called to act as a dispatchable resource, while the increased summer price differential acts as an overall shift to the Company's load forecast. (Vol. 6, Tr 2358.)

Further, as customers become more accustomed to hourly energy charges through implementation of the summer on-peak rate, they will better understand and react to Staff's proposed CPP provision. (Vol. 6, Tr 2357.) For these reasons, the Commission should approve Staff's proposed critical peak provision.

H. Staff recommends that the Commission reject the Company's proposed universal peak rewards (UPR) provision.

1. The UPR violates MCL 460.1095(1)a.

The Company's proposed UPR provision violates PA 342 of 2016 and should be rejected. MCL 460.1095(1)a, states that the Commission should approve programs on a voluntary basis to:

[p]romote load management in appropriate circumstances, including expansion of existing and establishment of new load management programs in which an electric provider may manage the operation of energy consuming devices and remotely shut down air conditioning or other energy intensive systems of participating customers, demand response programs that use time of day pricing and dynamic rate pricing, and similar programs, for utility customers that have advanced metering infrastructure... [MCL 460.1095(1)].

The Company's UPR program is a demand response program that uses time of day pricing and dynamic rate pricing for customers with AMI. However, those programs must be voluntarily imposed upon utilities and customers.

Customers are to agree to the program. The statute states:

Electric provider participation and customer enrollment in such programs are voluntary. However, electric providers whose rates are regulated by the Commission and whose rates include the cost of advanced metering infrastructure shall offer commission-approved demand response programs. The programs may provide incentives for customer participation and shall include customer protection provisions as required by the commission. To participate in a program, a customer shall **agree** to remain in the program for at least 1 year. [MCL 460.1095(1); Emphasis added.]

The Company's UPR provision is a demand response rate, intended to change bills based on usage or lack thereof during peak times, and it is not voluntary. While the customer may opt-out of receiving notification of critical event days, all customers will still receive a bill credit for energy use reduction during the event. (Doc No.

334, Vol. 5, Tr 1807.) Enrollment is imposed on all customers, and the resulting bill credit may still be earned by any customer. The Customer may choose to opt-out of Company messaging, but not receiving a bill credit. In other words, customers would be enrolled in the program without deliberate action to do so, and later they can only unenroll from the informational *part* of the program. (Doc No. 342, Vol. 6, Tr 2364-2365.)

The Company claims that the UPR does not violate the statute because a customer can choose to change their behavior and are not penalized if they do not. (Vol. 5, Tr 1830.) They instead are not rewarded for maintaining the status quo. However, the customer is still enrolled in the program. Just because customers are not penalized for non-participation in a critical event does not mean that they are enrolled in the program voluntarily. The law is not conditioned on whether the customer is penalized or not, but whether the customer has voluntarily agreed to enroll.

The relevant portion of the statute requires that: “Electric provider participation and *customer enrollment* in such programs are *voluntary*.” MCL 460.95(1)a. Under the Company’s proposal enrollment would not be voluntary, because residential customers would be enrolled in the provision by default; regardless of the effects on the customer’s monthly bill. Volunteering is a deliberate action taken by the customer, and not the absence of action. Opt-out DR programs, like the Company’s proposed UPR, are not voluntary because the customer does not volunteer to enroll in the program, but rather only has the opportunity to unenroll.

The opportunity to enroll is not the opportunity to unenroll. The availability of the choice to participate in the program is not the same as the customer making that choice. The Company's proposed UPR provision should be rejected by the Commission because it violates the statute.

i. The UPR is not effective and trying to increase resource size is no excuse.

The UPR is not effective, due to it being involuntary, no matter how big it may be. The Company argues that opt-out programs require substantially less resources than if they had to enroll the customers in an opt-in program. (Doc No. 334, Vol. 5, TR 1829.) Essentially, the Company argues that it would be too difficult to convince customers to opt-in. Certainly, the Company can find cost savings and gain experience to aid them in outreach for an opt-in DR rate, perhaps even through the pilot phase of implementing the summer on-peak rate.

The Company claims that opt-out programs produce a larger DR resource because of the inherently higher participation rate. (Doc No. 334, Vol. 5, Tr 1829.) Staff does not dispute that opt-out programs produce much higher levels of participation, but also recognizes that the magnitude of the DR resource provided by each customer suffers when customers are involuntarily enrolled. (Vol. 5, Tr 1829.) Customers who opt-in to voluntary demand response rate reduce on-peak demand, on average, significantly more than customers on an opt-out rate. (Company Exhibit A-162, p 45-46.)

Staff expects that the per-customer DR capacity will suffer even more when the opt-out program is structured like the proposed universal peak reward. The UPR compares customers usage to prior usage. Customers will be unaware of the baseline to which they are responding, and thus will not be able to directly connect load shifting activities will bill savings. (Doc. No. 342, Vol. 6 Tr 2363.) The Company disagrees and claims that the customer need only know that a critical event is taking place to cause a load reduction. (Doc No. 334, Vol. 5, Tr 1831.) However, under the proposed UPR provision the customer will have no way of observing the direct effects of their load shifting on their monthly bill. (Doc. No. 342, Vol. 6, Tr 2363.) In fact, because the baseline may vary for each critical event, if the customer shifts the same amount of load in two separate events, they may receive different bill credits, which could be confusing for customers. Further compounding this information asymmetry is the fact that the baseline is a computed figure derived from the Company's demand response management system (DRMS), and amounts to, essentially, an estimated bill. (Doc No. 342, Vol 6, Tr 2363.) The Company endeavors to calculate a more perfect baseline in the future. (Doc No. 334, Vol. 5, Tr 1831-1832.) Ultimately, however, it is impossible to ever arrive at what a customer's load *would have been* had that customers not shifted load.

ii. The UPR results in free-ridership.

The Company's proposed UPR provision suffers from the problem of free-ridership. Free-ridership is an economic term for when a consumer gains benefits

from a public good without paying the costs for that good. (Vol. 6, Tr 2361.) For the proposed UPR provision the “costs” are the efforts made by customers to shift or reduce usage during critical events. (Vol. 6, Tr 2362.) The problem with free-ridership for the UPR provision is therefore two-fold: it includes all customers regardless of their choice to volunteer for the provision and rewards customers regardless of their efforts to shift load. It is not promoting a reduction in load in many instances, though, that is what it purports to do.

Staff admits that its proposed CPP provision may also be produce a free-rider problem, because customers may also lower their bills without engaging in load shifting activities. (Doc No. 334, Vol. 5, TR 1828.) However, the difference in free-ridership problems between Staff and the Company’s proposals is a matter of scale. Staff’s proposed CPP provision is opt-in and will likely see fewer participants than the Company’s proposed opt-out UPR provision. (Doc No. 334, Vol. 5, Tr 1829.) It follows that if both proposals suffer from free-ridership at the individual customer level, then Staff’s proposal will result in a significantly lower *total* amount of free-ridership than the Company’s proposal. Sending demand response triggering signals, which are not clear, through the UPR, to 93% of the Company’s 1.6 million residential customers will result in many more customers being rewarded for unintentional load shifting behavior than the relatively smaller group of customers on the proposed CPP provision. Staff’s proposal provides a DR program to customers that involves no guess-work regarding their imputed baseline usage, while the Company’s proposal may not send clear signals to customers on how their

behavior impacts their monthly bills. (Doc No. 342; Vol. 6, Tr 2363.) In fact, sending unclear price signaling over time may result in customers failing to shift load, if customers' baselines afforded a discount previously and caused an anticipated result without much shifting. This would counter the purpose of the demand response program in the first place.

The Company's UPR provision should be rejected because it violates PA 342 of 2016, sends ineffective price signals, and suffers from a large-scale free-ridership problem.

2. It is appropriate to apply the same distribution energy rates to all residential customers.

MEC-NRDC-SC claimed that "it is not appropriate to apply the same distribution rates given that distribution cost of service allocations per unit of energy vary between [residential] rate classes." (Doc No. 342, Vol. 6, Tr 2635.) However, all residential customers are included in one rate class in the cost of service study (COSS). (Vol. 6, Tr 2344.) Customers that receive substantially similar distribution service should pay the same distribution rates. Residential customers are served substantially similarly by the Company, so the class was incorporated into one cost column and load profile, which includes distribution-related costs. (Doc No. 334, Vol. 5, Tr 1690.) Residential customers' distribution costs are treated as a whole in the COSS and therefore residential distribution rates should be designed as a whole.

3. The proposed summer on-peak rate is not a demand response rate.

The difference between a demand response rate and any other type of rate is the intention or purpose of revenue collection. (Doc No. 342; Vol 6, Tr 2354.) The intent of a demand response rate is to induce behavior in customers that reduces costs faced by the utility. For example, demand response could cause cost reduction from delayed or reduced need for capital investment or from reduced need for purchased power. *Id.* Demand response accomplishes this cost reduction by encouraging customers to reduce on-peak energy consumption or lower peaks. A time-of-use (TOU) demand response rate structure is not necessarily designed for cost recovery. A TOU demand response rate is explicitly designed to shift the customer's load. The proposed summer on-peak rate is designed to recover revenue assigned to the class in the COSS in a manner consistent with the causation of those costs. The proposed summer on-peak rate is intended to recover current costs as they vary, whereas a demand response rate's intent is to change costs over time.

The Company's proposed summer on-peak rate charges a higher power supply capacity rate in the summer months during a designated daily peak period. The difference in price between the summer peak period and all other hours is based on the difference between the average locational marginal prices (LMP) of those periods. (Doc No. 342, Vol. 6, Tr 2355.) Average LMP prices are used as a proxy for cost differences. The time-varying rates represent actual variance in costs faced by the utility and caused by the customer.

The distinction is important because the purpose of the rate should inform its design, and the results of that design should then be evaluated for reasonableness and efficacy, in that order. Rate design should be evaluated to determine if the rate accomplishes its purpose. (Vol. 6, Tr 2355.) The standard residential rate is evaluated on how well it recovers its allocated revenue requirement, and a demand response rate is evaluated on how well it encourages customer behavior and if it is cost effective. For these reasons the Commission should approve the Company's proposed summer on-peak rate.

J. Commercial and Industrial Rate Design

1. The Staff's GPD cost based rates should be adopted.

Kroger and HSC argue that Staff and the Company's proposed distribution charges for Rate GPD are not cost based. (Doc No. 334, Vol. 5, Tr 1408-1409; Doc No. 342, Vol. 6 Tr 2240.) The Staff disagrees and points out below the failings in Kroger and HSC's analysis.

HSC and Kroger disagree in their proposed Rate GPD distribution rate designs. (Vol 5, Tr 1410.) Specifically, the parties disagree on which costs and revenues to include when analyzing any cross-voltage-level subsidy among Rate GPD customers, and on which rate elements (i.e. monthly customer charge, demand charges) require adjustment from the Company and Staff's proposed rate design. Further, Kroger contends that Rate GPD power supply costs are also misaligned between the voltage levels. (Vol. 5, Tr 1412-1413.) ABATE disagreed with Kroger's conclusions regarding Rate GPD rate design, and notes that reallocation of

interruptible credits, as approved by the Commission, distorts the rates of return among the Rate GPD voltage levels. (Doc No. 346, Vol. 7, Tr 3547.)

Staff did not address Hemlock Semiconductor (HSC) and Kroger's assessments of and recommendations on Rate GPD distribution in testimony or power supply rate design, except for Staff's recommendation to reject HSC's proposed substation ownership credit. (Doc No. 342, Vol. 6, Tr 2342.)

Kroger could not follow how Staff's rate design revenue for Rate GPD matched costs. (Vol. 5, Tr 1415.) Even including adjustments for interruptible credits, EIP capacity, Rate GP-GPD crossing point, self-generation, senior citizen, and income assistance credits Kroger supposes that Staff's rate design revenue for Rate GPD does not match costs by voltage level. (Doc No. 334, Vol. 5, Tr 1416.) When reallocating costs for rate design, both Staff and the Company combine Rate GPD's voltage levels, so reallocated costs accrue to the entire rate. (Staff Exhibit S-6, F-2.1, note 3.) Further, Kroger failed to provide any references or workpaper showing how it arrived at the supposed "Staff Proposed Costs" to which Kroger compares rate design revenue for Rate GPD by voltage level. (Vol. 5, Tr 1417.) The rate design revenues by voltage level for Rate GPD made by Kroger also do not appear to match Staff's rate design model. (Doc. No. 344, Exhibit S-6, F-3, p 17, line 39; p 18, line 35; and p 19, line 33.) The Commission should dismiss Kroger's recommendation to reject Staff's Rate GPD rate design because of misconceived errors and adopt Staff's Rate GPD, based on Staff's analysis.

2. Staff recommends maintaining a crossing point adjustment for rates GP and GPD but recommends examining the effects of phasing out the adjustment.

Currently Rates GP and GPD are designed with an adjustment that shifts revenue requirement between the rates in order to prevent customers from migrating between them. (Doc No. 342, Vol. 6, Tr 2366.) According to Staff's rate design model the crossing point adjustment required to prevent migration between rates shifts \$20 million of revenue requirement from Rate GPD to Rate GP.

In order to reduce the subsidy paid by Rate GP customers on behalf of Rate GPD Staff recommends increasing the load factor crossing point to 50%, so the adjustment is reduced to \$13 million. (Doc. No. 344, Staff Exhibit S-6, Schedule F-2.1, line 5.) The effect of increasing the load factor crossing point would make the economic threshold for Rate GPD higher, that is, more customers would be better off on Rate GP than GPD. The crossing point adjustment is an adjustment to the cost of service, which is done in the rate design step. Essentially, the adjustment is in response to customer migration between rates, and not rooted in the cost to serve customers. (Vol. 6, Tr 2367.) According to the Company, the adjustment is necessary to avoid the cost and administrative burden of transferring customers to a new rate. (Doc No. 334, Vol. 5, Tr 1559-1560.)

ABATE disagrees with Staff's proposal to eventually eliminate the crossing point adjustment. (Doc No. 346, Vol. 7, Tr 3546.) ABATE argues that the fundamental purpose of preventing customer migration between rates is that it provides revenue stability for the Company, and thus rate stability for customers. (Doc No. 346, Vol. 7, Tr 3545.) Also, ABATE contends that because Staff makes

other adjustments to the cost of service through rate design that the crossing point adjustment can also be made in a similar fashion. (Vol. 7, Tr 3546.) What ABATE misses in Staff's argument is that the adjustment would not have to be made in the rate design at all if customers were allowed to actually migrate between rates. (Doc No. 342, Vol. 6, Tr 2367.)

Kroger agrees, in general, with Staff that cost allocation is best done in the COSS. (Vol. 5, Tr 1418.) Kroger also notes that Rate GP is in effect a specialty rate that caters to customers for whom a demand charge would be burdensome due to their low load factor, and Staff's proposal would encourage more demand-related cost recovery through energy charges. (Doc No. 334, Vol. 5, Tr 1418.) Staff agrees with Kroger's analysis of Rate GP. Staff acknowledges that Rate GP's lack of demand charge also does not efficiently recover demand-related costs. Staff suggests that an analysis of the proper load factor threshold should be completed so as to reduce the inefficient rate recovery of primary class demand costs.

While the Company disagreed with Staff that a change in the crossing point adjustment was warranted in the instant case, the Company agreed to endeavor to identify the effects of minimizing the adjustment in the Company's next rate case. (Vol. 5, Tr 1582-1583.) Staff agrees with this approach and recognizes that the process of phasing out the adjustment requires iterative rate design and cost of service modelling. Staff supports the Company's endeavor to perform such an analysis and recommends that the Commission require it in the Company's filing in its next rate case.

3. Staff recommends continued allocation of capacity costs to Rate EIP, and that the Company include Rate EIP load profiles in future COSSs.

Staff does not recommend a change to the Commission-approved method for developing the revenue requirement for Rate EIP, which adjust Rate EIP's revenues to match the overall rate increase for Rate GPD. (Doc. No. 342, Vol. 6, Tr 2367.) The COSS should include load profiles that appropriately allocate capacity costs for Rate EIP, so that the additional adjustment in the rate design model is no longer necessary. (Vol. 6, Tr 2368. Staff recommends that the Commission require the Company to develop a COSS that includes capacity costs for Rate EIP customers in its next general rate case.

The Company claims that there are too few customers on Rate EIP to accurately construct a load profile for inclusion in future COSSs. (Doc No. 334, Vol. 5, Tr 1686.) It is unclear from the Company's rebuttal testimony whether the Company is willing to analyze Rate EIP customers to develop their load profile. (Vol. 5, Tr 1686.) Rate EIP has existed since 2015 and certainly that is enough time to generate the data necessary to develop a load profile for its customers. *In re Consumers Energy Company 2014-2015 Electric General Rate Case*, MPSC Case No. U-17735, 11/19/2015 Order, pp 106-109, Doc. No. 381.

ABATE claims that Staff is incorrect in its assessment that Rate EIP customers are not allocated capacity costs in the COSS. (Doc. No. 346, Vol. 7, Tr 3543.) Staff was simply echoing the Company's direct testimony that states Rate EIP customers are allocated negative capacity costs as a result of the COSS. (Vol. 5, Tr 1560; Doc No. 342, Vol. 6, Tr 2367.) Staff is not, as ABATE states, asserting

“that Rate EIP is getting a free ride.” (Vol. 7, Tr 3543.) Again, Staff does not recommend a change to the Commission-approved method for allocating capacity costs to Rate EIP in the instant case. (Doc No. 342, Vol. 6, Tr 2367.)

Kroger misunderstood how Staff’s rate design developed the Rate EIP revenue requirement. (Doc No. 334, Vol. 5, Tr 1419.) Staff allocated \$8 million in additional revenue requirement to Rate EIP in order to match Rate EIP’s overall rate increase with that of Rate GPD. (Doc No. 342, Vol. 6, Tr 2367.) Staff provided its reasoning in Staff witness David Isakson’s direct testimony. *Id.* The Company also used the same method to adjust Rate EIP’s revenue requirement, and the difference in magnitude between Staff and the Company’s adjustment is derived from fundamental differences in each party’s COSS. (Doc No. 334, Vol. 5, Tr 1560-1561.) Again, Staff does not recommend a change to the commission-approved method for allocating capacity costs to Rate EIP in the instant case. (Doc No. 342, Vol. 6, Tr 2367.) For these reasons, the Commission should approve Staff’s allocation of Rate EIP capacity costs and reject ABATE and HSC’s arguments against this established methodology.

4. The Commission should reject HSC’s proposed substation ownership credit that includes specific high voltage distribution assets.

HSC proposed a new calculation of the substation ownership credit that relies on a proration of specific miles of dedicated overhead line for customer-owned substations. (Doc No. 342; 6 TR 2234.) HSC witness Alderson provided an analysis

of customer substation ownership as it relates to miles of 138kV overhead and concludes:

[T]he vast majority of customers that own their own 138kV substation are served by dedicated 138kV overhead conductor of measurable and discrete length on an isolated distribution circuit, and because these customers are not served by the remaining shared 138kV overhead distribution network that interconnects other Voltage Level 1 customers to each other and to the larger Consumers distribution system, I recommend the Substation Ownership Credit Include an offset for 80% of allocated 138kV overhead conductor costs.” [Doc No. 342, Vol. 6, Tr 2234.]

Staff disagrees that such granular dissection of rates is appropriate. Designing any rate using specific miles of overhead line used to serve such few customers is too narrow to be reliable for use beyond the test-year. Rates are both designed to recover test year revenues, but also to incorporate long-term system conditions, customer behavior, billing determinants, etc. (Doc No. 342, Vol. 6, Tr 2341.) Rate design must consider the long-term because rates may not necessarily change quickly enough incorporate changes in capital or O&M for 138kV overhead conductors. A credit designed to reflect small, specific items leaves the credit acutely susceptible to instability depending on investment in those items. The 14.16 miles of overhead line identified by HSC could vary significantly with one additional customer-owned substation, and thus the substation ownership credit would also vary significantly.

Rates cannot perfectly reflect individual customer costs at all times, because that is an exercise in futility, so rates are designed for entire classes of customers. The average customer cost in a class is not expected to differ but generally not vary significantly from one another on a relative scale. Customer classes are large and

diverse enough to absorb a new customer without drastically increasing average costs for the class. (Doc No. 342, 6 Tr 2342.) HSC's substation ownership credit involves so few distribution assets that any change by the Company or customer would have a large impact on the credit.

Further, HSC argued that "the vast majority" of customers who own their own 138kV substations are primarily isolated on dedicated circuits that do not connect with the Company's distribution network, so the substation ownership credit is understated "because it does not properly credit these customers for the 128kV overhead line costs that are not used to serve them." (Doc No. 342, Vol. 6, Tr 2228.) *Majority* does not equate to *entirety*, and *primarily* does not mean *necessarily*. Because HSC did not show that *all* substation owning customers are not connected to the remaining 138kV distribution network, then the identified 14.16 miles of 138kV line should not be included as the basis for HSC's proposed credit calculation.

The Company also disagreed with HSC's proposal. (Doc No. 334, Vol. 5, Tr 1697.) According to the Company, HSC mischaracterized information received through discovery in its analysis of the substation ownership credit, failed to reconcile the difference in timing between discovery response data and data used for the COSS and also did not include retail open access (ROA) customers' billing determinants in its proposed credit calculation. (Vol. 5, Tr 1697-1698.)

For these reasons the Commission should reject HSC's proposed substation ownership credit calculations.

5. **Staff recommends that penalty charges for the propose GI2 provision match existing non-interruption penalty charges for the existing GI1 provision of \$50 per kW.**

The Company proposed a new interruptible service provision for Rate GPD called GPD-GI2. The proposal includes a penalty charge for non-interruption of \$10 per kW. While a penalty charge for non-interruption is standard across most utilities, the proposed amount of the charge is not. (Doc No. 342; Vol. 6, Tr 2369.) Aligning penalty charges for interruptible provisions reduces confusion for the customer when considering participation. Further, there is no fundamental reason why two rates that aim to accomplish the same goal, peak load reduction, should be penalized differently. The non-interruption penalty for Rate GPD-GI2 should match the penalty for Rate GPD-GI1.

K. Other Rate Design Issues

1. **The Commission should reject HSC's proposal to recover costs associated with residential income assistance (RIA) and residential senior citizen (RSC) credits through power supply charges.**

HSC proposed to recover costs associated with RIA and RSC credits (referred to as "skewing" by HSC) through both distribution and power supply charges. (Doc No. 342; Vol. 6 Tr 2243.) The Commission-approved method of recovering these costs from all customers is through distribution charges only. (6 TR 2343.) If a portion of the allocated RIA and RSC costs were recovered through production cost recovery, then not all customers would pay those costs equitably, because not all GPD customers pay production charges (i.e. Alternative Energy Supplier

customers). (Doc No. 342; Vol. 6, Tr 2344.) RIA and RSC costs are neither power supply nor distribution-related, but recovery through distribution charges ensures that all customers pay for them equitably. The Company also disagrees with HSC and notes that “Given that low income customers have not been provided an opportunity to participate in ROA, it seems unreasonable to allow ROA customers to avoid paying a comparable amount as Full Service customers for assistance programs.” (Doc No. 334, Vol. 5, Tr 1585.) For these reasons, the Commission should reject HSC’s proposal to recover residential credits through power supply charges.

2. Staff recommends the allocation of interruptible credits, including residential customer interruptible credits, to customers based on firm load.

ABATE proposed to allocate interruptible credits to all capacity customers based on firm load, and not all customers including those who provide interruptible capacity. (Doc No. 346, Vol. 7, Tr 3489.)

Staff agrees with ABATE that customers that provide the Company with interruptible load, a demand response (DR) customer for whom the Company does not acquire capacity, should not also be allocated the costs of acquiring their own DR resource. Staff recommends that the same principal be extended to residential customers on the Company’s Peak Power Savers program, who also provide an interruptible resource. (Doc No. 342; Vol. 6, Tr 2336-2337.) For these reasons, the Commission should approve ABATE’s proposal, and extend the methodology to residential interruptible credits.

3. Staff recommends that the company-proposed substation ownership credit be allocated to all customers based on total cost of service.

Staff, along with the Company, agrees with HSC's recommendation that the substation ownership credit be allocated to all customers, based on total cost of service rather than firm-load. HSC proposed to allocate the substation ownership credit to all customers in a fashion similar to interruptible credits. (Doc No. 342, 6 TR 2244.) The Company agreed with HSC's proposal. (Doc No. 334, Vol. 5, Tr 1585). The substation ownership credit provides a benefit to all ratepayers in a similar way that interruptible customers provide a benefit to all customers.

Thus, the credit should not be allocated on firm-load. It should be allocated like the interruptible credit allocation proposed by ABATE and supported by Staff and the Company. For these reasons, the Commission should approve HSC's proposal for allocating the costs of the Company's proposed substation ownership credit, based on total cost of service, not firm-load.

a. Standby Tariff (GSG-2)

The Commission should base demand charges on measured demand and not contracted demand. In direct testimony, Staff recommends components of the GSG-2 tariff that are based on contracted amounts be based on measured amounts. (Vol. 6, Tr 2470.) In rebuttal testimony, the Company witness Laura Collins agrees (Vol. 5, Tr 1583.) Although not clarified in Staff's direct testimony, Staff intended demand charges for distribution to be based on the peak annual demand, also referred to as an 11-month ratchet. EIBC witness Scripps makes several arguments

for standby customers and partial usage of the distribution system. (Vol. 6, Tr 2654, 2661.) In rebuttal testimony, Staff witness Krause describes how distribution use is measured for the purposes of cost allocation and rate design (Vol. 6, Tr 2476.) The definition of partial use of the distribution system for GSG-2 customers by EIBC was rejected in Case No. U-18322 and should be rejected again.

b. Electric Vehicle -Tariff Issues

MEC witness Baumhefner proposes increasing the ratio between on-peak and off-peak charging, as well as suggesting time-of-use charges for distribution. (Vol. 6, Tr 2688-2694.) Staff witness Krause in rebuttal testimony describes the first proposal as premature, and the second as inconsistent with cost causation (Vol.6, Tr2633-2644.) Additionally, MEC/NRDC/SC/EIBC/EC witness Jester proposes a parking lot tariff for electric vehicles. (Vol. 6, Tr 2645.) Staff witness Krause described the proposal as vague, and again premature (Vol. 6, Tr. 2474.) While not necessarily recommending that these issues be permanently rejected, Staff recommends that all three of these EV tariff proposals be rejected in this case.

VIII. Accounting Approvals

A. Traverse City Service Center acquisition costs should be approved.

Staff recommends that the Commission approve the Company's proposed accounting treatment of Traverse City Service Center (TSCS) acquisition costs. Company witness Daniel L. Harry requests that the Commission approve an amortization period of 15 years and the recording of amortization expense in

Account 406. (Doc No. 334, Vol. 5, Tr 2123.) Staff witness Charles E. Putnam agrees stating this is a sound accounting treatment and the same as the treatment proposed by the Company for its Saginaw Service Center Acquisition costs in Case No. U-17735. *In re Consumers Energy Company 2014-2015 Electric General Rate Case*, MPSC Case No. U-17735, 11/19/2015 Order, Doc. No. 381. No party opposed the proposal in that case, and the request was granted. (Doc No. 342, Vol. 6, Tr 2553.) No party has opposed the proposal in this case, and Staff recommends its approval.

B. Regulatory accounting for investments in cloud-based technologies should be approved.

Staff recommends that the Commission approve the Company's proposed accounting treatment for the costs of its cloud-based technology investments. Witness Harry requests that the Commission approve the accounting authority to accumulate Information Technology project implementation costs for cloud-based solutions in Plant Account 303, Miscellaneous Intangible Plant, and amortize the intangible asset to expense over the expected useful life of the cloud-based solution. (Doc No. 334, Vol. 5, Tr 2123-2124.) Witness Putnam agrees. Capitalizing the costs associated with cloud-based solutions will remove financial hurdles that hinder the Company from realizing the benefits of cloud-based technologies and is a reasonable request. (Doc No. 342, Vol. 6, Tr 2554). No party has opposed the proposal in this case, and the accounting treatment for the costs cloud-based technology investments should be approved.

C. Electronic Vehicle (EV) Charging Deferred Accounting should be approved with one caveat.

Staff recommends that the Commission approve, with one modification, the Company's proposed accounting treatment for the costs of its EV Charging Program. Witness Harry requests that the Commission: (i) authorize the recognition of a regulatory asset to recognize deferred EV program costs; (ii) authorize the amortization of these costs over 10 years; (iii) include recovery of amortization expense in rates and; (iv) include the deferred net unamortized balance of EV Program costs in rate base. (Doc No. 334, Vol. 5, Tr 2127.)

Witness Putnam agrees with the Company's proposal with one modification. The Commission Order in DTE Energy Company's Case No. U-17767 approved DTE's request to amortize previously deferred EV costs over a 5-year period. Staff proposes that the Consumers EV Charging Program also be amortized over 5 years. (Doc. No. 342, Vol. 6, Tr 2555.) The Company agrees that 5-year amortization period is reasonable. (Vol. 5, Tr 2130.)

Only one party opposed the Company's proposal. Environmental Law & Policy Center witness Karl R. Rábago concluded that the Company failed to adequately support its proposal to treat rebate expenses as a capital investment for ratemaking purposes. He adds that the uncertainty in this pilot program is the strongest argument against the Company's proposed accounting treatment. (Doc No. 333, Vol. 4, Tr 783.) Company witness Michael J. Delaney counters that the uncertainty of customer participation in this pilot program aligns well with the regulatory asset approach as cost recovery will be dependent on actual, not

projected expenditures. (Vol. 4, Tr 1080.) Witness Delaney also notes that neither Staff of any other intervenor agreed with witness Rábago's conclusions and that four witnesses provided direct testimony in support of the Company's proposed regulatory asset treatment. (Vol. 4, Tr 1074.)

IX. The MPSC recommends the Electrical Vehicle Pilot program.

The MPSC Staff has reviewed Consumers proposed PowerMIDrive pilot. Overall, the pilot has a solid framework, appears innovative and well thought out, meeting the criteria set by the Commission in U-18368. The PowerMIDrive pilot, implemented over a 3-year period, is a prudent course of action and should be approved, with spending capped at \$7,500,000 as requested by the company, plus an additional \$2,500,000 dedicated toward new or modified service connections and associated equipment, as recommended by Staff. (Vol. 6, Tr 2533.) Regarding the recommended additional funding, Staff testified that "Because the PowerMIDrive program is a critical information gathering pilot, it is reasonable and in the public interest for utility grid infrastructure needed to implement the pilot to be fully funded by the utility. This would make a more complete 'make ready' model for the pilot." (Vol. 6, Tr 2533.)

Staff recommends that utility investment in new or modified service connections associated with 'make-ready' charging infrastructure be excluded from the rebate program as they would be provided at no cost to site hosts participating in the pilot. (Vol. 6, Tr 2535.) The CIAC will need to be suspended at publicly available EV charging sites included in the pilot, for the term of the pilot, which is

three years from the date of the Commission order approving the PowerMIDrive pilot. (Vol. 6, Tr 2535.)

Rule C1.4 and Rule C6. need to be modified to accommodate the suspension of CIAC for the PowerMIDrive pilot. Staff suggests that both rules should have language added that states: *Contributions in Aid of Construction otherwise required by the Company may be suspended for publicly available AC Level 2 or DC Fast Charge sites participating in the PowerMIDrive pilot. Suspension is at the Company's sole discretion, for a term of three years from the date of Commission approval of the PowerMIDrive pilot.*

Staff recommends that the Commission should not approve specific rebate amounts for the residential, publicly available AC Level 2, and DCFC segments of the pilot. The utility should have considerable flexibility to adjust rebate amounts, over the course of the pilot, in response to pilot-implementation evaluation by the company and input from stakeholders including site-hosts. It is recommended that Consumers file in the U-20162 docket an initial rebate schedule for all pilot segments immediately prior to pilot implementation, and revisions as necessary over the course of the pilot. (Vol. 6, Tr 2538.)

Staff recommends that Consumers file an annual report detailing the progress and development of the pilot and suggests that the report should be filed in this case (U-20134.) Additionally, subsequent to each such filing, Staff suggests that it convene an informal technical conference to discuss the results. Intervenors

to the rate case, and other stakeholders would be invited to participate. (Vol. 6, Tr 2538.)⁷

X. Commission should reject the Company's request to recover distribution capital expenditures in 2020 and 2021 through an investment recovery mechanism (IRM).

Staff recommends that the Commission reject the Company's request for an investment recovery mechanism (IRM) in this proceeding. The Company is requesting the approval of approximately \$1.1 billion in capital investments in six distribution capital programs (New Business, Demand Failures, Asset Relocation, Reliability, Capacity, Tools and Technology) from 2020-2021 as part of the Company's IRM (A-107 (HJM-63).) In support of the prudence and reasonableness of these investments, the Company has provided their 5-year Electric Distribution Infrastructure Investment Plan (EDIIP) filed in the Commission Docket U-20134 on March 1, 2018 (Exhibit A-111 (TJS-1).) This 307-page exhibit was developed in response to the Commission Order issued on February 28, 2017 in Commission Docket No. U-17990. In re Consumers Energy Co, Case No. U-17990, 2/28/2017 Order, Doc. No. 401, p. 19)

This long-term planning document, per the Commission order, was intended to increase visibility into the system needs and facilitate review by the Staff, other parties, and the Commission outside the contested rate case process. *Id.* Currently,

⁷ Recovery of program costs should be deferred via regulatory asset accounting, using a five-year amortization period. See page 111 of this brief regarding accounting approvals.

the Commission is reviewing the Company's EDIIP, stakeholder feedback, and Staff's proposed framework for future distribution planning. As stated in the October 11, 2018 Order in U-17990, at page 18, provide further guidance on future iterations of planning following receipt of the Staff's report. *In re Consumers Energy Co*, Case No. U-17990, 10/11/2017 Order, p. 18, Doc. No. 424. This guidance on the future of the distribution planning process and plans is forthcoming. Staff anticipates the Commission will address whether an IRM is appropriate and necessary and provide further instructions on how it should be structured. (Vol 2, Tr 83.) Company witness Sparks, who supports the EDIIP exhibit, outlines the proposed IRM reporting, first the Company will file an annual reconciliation in accordance to the MPSC's filing requirements Part III, Attachment 11. Second, the Company will provide interim updates to Staff. Third, the Company will continue to file its Annual Report to the MPSC Regarding Electric Distribution System Performance Standards and Annual Power Quality Report.

The reconciliation of the IRM will consist of updating the revenue requirement associated with actual incremental capital investments made by the Company. If the actual capital investments are less than the Commission-approved amounts, a credit will be established to return the difference in revenue requirement. The Company is requesting that the IRM have unlimited flexibility in spending across each capital program and that the reconciliation be applied to total approved IRM capital spending rather than by program. (Doc. No. 326, Vol. 2, Tr 165-166.) The Company has stated that in order for the IRM to defer the next base

rate case filing until February 2021 there needs to be acceptable and timely rate relief in this proceeding and approval of the IRM as proposed in this proceeding. The Company would also request 14 days following the order to determine if it would commit to deferring the next electric general rate case. (Vol. 2, Tr 84.) No intervenors in the case have provided testimony in support of the Company's IRM. Intervenors have stated concerns with accountability, timing, lack of incentives/disincentives, utility risk reduction, cost allocation, and customer protections as rationale on why the Commission should not approve the Company's proposed IRM.

The Commission should reject the Company's proposed IRM due to an absence of evidentiary support for the reasonableness and necessity of proposed spending and a lack of customer protections to promote and ensure prudent operation of the IRM. As stated above, in support of the IRM, the Company has provided its five-year distribution plan or EDIIP and the a confidential excel model referred to as the GRID MD V1.1 (GRID MD) which seemingly underlies the spending plans outlined in the EDIIP. As outlined in the testimony of Company witness Anderson the GRID MD model, "help(s) predict system reliability performance based on funding for various electric distribution reliability programs. The Grid MD model is similar to previous reliability models but was constructed with a stronger emphasis placed on infrastructure replacement and with the longer-term goal of including distribution automation, DSCADA, and other modern technologies." (Vol. 5, Tr 1949.)

This statement clearly outlines Staff's concerns with the IRM spending plans for two of three basic reasons. First, the plans put projected program *funding* at the forefront, rather than being the results of objective system modeling and needs assessment. Second, the model has an inherent bias towards capital spending (infrastructure replacement) over least cost planning when developing a plan to meet the Governor's reliability goals. Staff posits that the GRID MD models primary focus is ensuring financial and shareholder goals of CMS Energy rather than cost effectively addressing system needs. (Vol. 6, Tr 2272-2274.) Staff witness Laruwe states specifically his concerns regarding the lack of nuance apparent in the model:

Staff is concerned that the Grid MD model is based upon funding for various electric distribution reliability programs, rather than a thorough analysis of the system's need for investment based on sound assumptions and modeling. The model is clearly attempting to spend a pre-determined amount of capital in reliability programs without regard for cost-effectiveness or affordability. Staff is also concerned that the model puts a stronger emphasis on infrastructure replacement rather than examining all available options and choosing the most cost-effective solution. The model appears to have a strong shareholder bias as it is completely removed from the needs of the system and emphasizes rate base growth over cost effective and prudent decision making. Therefore, Grid MD model does not represent a prudent and reasonable approach to setting future spending plans for an IRM. [Vol. 6 Tr, 2273-2274.]

Not only is the GRID, MD model lacking in innovation, the model also includes tree trimming program which is outside of the scope of the IRM. The greatest reliability benefit modeled in the GRID MD is, in fact, the line clearing program which is outside the scope of the proposed IRM and would not be subject to reconciliation during the IRM time period.

Third, the Company is also not committing to actually performing any of the work that underlies the IRM spending plans. Instead the Company is proposing that the reconciliation be held at the program spending level without consideration of actual work performed. (Doc. No. 326, Vol. 2, Tr 341.) Without a commitment to performance of the replacement of assets that supports the IRM spending, it is impossible to understand the value that customer will receive from its approval. Under the Company's construct, the Company could not perform any of the work outlined in this case but spend the IRM revenue requirement and not have any obligation to refund customers. The lack of performance metrics in the Company's request presents an unfair risk to rate payers as spending money does not ensure customer value. Customer value is driven by cost effectively deploying assets and technology to address distribution grid issues. Any reasonable and meaningful reconciliation should take into consideration performance as well as spending. (Vol. 6, Tr 2274.) Staff and intervenors will only know what work was performed when the Company files its reconciliation at which point the only recourse will be arguing the disallowance of work already performed. (Doc. No. 326, Vol. 2, Tr 165-166.) Staff urges the Commission to act cautiously on approving any long-term distribution capital investments based projected future benefits. The Company's AMI deployment serves as an example of the risks associated with benefit projections.

Case Number	Capital Benefits 2019	Capital Costs 2007-2019	Capital Benefits 2007-2019	Source
U-16794	\$89,920,000	\$616,742,000	\$246,241,000	Commission Docket U-16794 Exhibit

				A-45 (MKT-3)
U-20134	\$18,703,000	\$651,361,000	\$45,717,000	Exhibit A-116 (LDW-3)
Variation	(\$71,217,000)	\$34,619,000	(\$200,524,000)	

The benefits shortfall outlined above has been the responsibility of the rate payers over the last 13 years as well as the incremental capital. During the same period the Company’s shareholders have seen the benefit of rate base growth, above and beyond the initial projection, which they have earned a return on, without having to absorb any of the benefits shortfall. This disproportionate risk will exist if the Commission approves the IRM without performance metrics and incentives/disincentives. Absent these protections the Commission should reject the Company’s request for an IRM.

Staff and Intervenors also agree that the timing of the Company’s request for an IRM based upon their EDIIP is inappropriate given the timeline of the Commission’s initial distribution planning process. As stated by the Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club in their direct testimony, the Commission ordered the preparation of the EDIIP in Case U-17990 and established a process for reviewing it in Case No U-20147. That process is ongoing and should not be bypassed by the Commission in the present case. (6 Tr 2607.) Concerns with the timing are further elaborated on by witness Villareal This is problematic because the Commission has yet to act on the 5-Year plan as being reasonable, consistent with the directions of the Commission, or as a document that can be relied upon for justification for significant investments in the distribution system. In essence, the Commission is being asked to rely upon a

document that is still undergoing Commission review, is the subject of substantial comments from stakeholders with concerns about the content and fails to fully describe a distribution system planning process, as requested by the Commission in that docket. As such, it would not be reasonable in this proceeding to rely on the *unapproved* 5 Year Plan to authorize the Company to recover from customers the proposed distribution system spending. (6 Tr 2673-2674). Aside from the Company not allowing the distribution planning process play out, the use of the plan to seek regulatory approvals for cost recovery in the current case seems contrary to the direction outlined by the Commission in U-17990:

The Commission believes there are significant benefits associated with a comprehensive and forward-looking approach to distribution planning that leverages greater Commission and stakeholder input. A longer-term planning approach will help the Commission and stakeholders better understand the long-term goals and objectives underlying utility investment plans and how the execution of these plans can meet these goals and objectives in an affordable manner. While this planning process would not provide regulatory approvals for cost recovery purposes, the transparency around the need for, scope of, and expected outcomes resulting from specific investment strategies may facilitate ratemaking processes and the development of potential new approaches to provide greater regulatory certainty, such as performance-based ratemaking currently being studied pursuant to the 2016 energy laws. [*In re Consumers Energy Co*, Case No. U-17990, 10/11/2017 Order, Doc. No. 424, p 17.]

In rebuttal testimony Company witness Timothy J. Sparks argues that the Company's IRM based upon the EDIIP is hardly vague, based on its volume and breakdowns of scope and investment.

The EDIIP includes nearly 300 pages of data and narrative detail presenting the Company's future 13 vision for the electric distribution system, performance objectives and metrics, current state of the system, and investment and maintenance plans for 2018 through 2022. Nearly two-thirds of the report consists of detailed breakdowns of

planned capital investments and scope for each program, sub-program, and investment category over that five-year period. Each program section of the report provides detailed explanations of the investment logic and prioritization process that the Company uses to make reasonable and prudent investments for the benefit of its customers. Mr. Laruwe neither acknowledges nor specifically addresses any of the supporting content presented in the EDIIP. Moreover, Mr. Laruwe does not establish any rationale by which the EDIIP could have been considered “vague” as a support for the Company’s spending plans. [Doc. No. 326, Vol. 2, TR 170.]

Contrary to Company Witness Timothy J. Sparks statement, Staff’s rationale for the statement of the information contained in the EDIIP being vague and inadequate for prudency review is clearly outlined in the direct testimony of Staff witness Ryan S. Laruwe. Mr. Laruwe points to a lack of transparency into load forecasting, power-flow modeling, and other system data in support of the necessity and reasonableness of planned investments. (Vol. 6, TR 2271.) Witness Laruwe continues to state, as the record reveals, that the EDIIP lacks any critical cost/benefit analysis or investments to ensure the plans are cost-effective and therefore reasonable. In contrast, Staff’s proposed framework for distribution planning outlines recommended improvements for future iterations of 5-year plans specifically to aide in prudency review:

The framework also requires greater consideration of non-traditional alternatives through the use of a consensus cost-benefit framework to aid in analysis of utility decision making. Without this incremental information, it is not possible for the Commission, Staff, or intervenors to perform an independent analysis of the overall prudency of the Company’s projected spending plans necessary prior to any rate increase. Staff’s report explains that any future plan filed under the proposed framework could be reasonably considered for IRM treatment with additional accountability measures in place. [6 Tr, 2271-2272]

Without a rigorous plan for reconciliation of costs based on objective measures, it is difficult to justify an IRM.

Furthermore, the Company has not supported their ask with project level data which is essential in determining the reasonableness of any distribution level investment as customer value and benefits will be heavily dependent on the locational value of investments. Witness Laruwe states:

Staff tried to obtain more evidence in support of the EDIIP spending plans through the discovery process. (Exhibit S-15.1 (RSL-1) and Exhibit S-15.2 (RSL-72)). In response to Staff's request for more information the Company provided multiple confidential assessments of its High Voltage Distribution (HVD) system that appear to outline a number of potential projects in the coming years. However, as stated in the discovery response, these project plans are not exhaustive and do not outlined the necessity for the entirety of the HVD spending. The Company also did not provide any information that would attempt to connect these assessments to the proposed spending plans for 2018-2022. Without this connection, the provided information is little help for performing a prudency review of the requested spending plans. [Vol. 6, Tr 2272.]

Thus, discovery has not yielded adequate project level information, which is also necessary to implement a meaningful reconciliation process. A reasonable reconciliation needs to view the Company's ability to perform the necessary work on the system, where it will provide the greatest value, in a cost-effective manner--not just the Company's ability to spend a pre-determined amount of money. Staff posits that the Company's presentation of evidence for the IRM is vague in terms of what is typically utilized in executing a prudency review is clearly outlined in direct testimony (Vol 6, Tr 2271), contrary to the statements of Company witness Timothy J. Sparks in his rebuttal testimony.

As presented in this case and outlined above, the IRM proposed represents a low risk, guaranteed reward for the Company and its shareholders, and a high-risk investment for rate payers. Until this disproportionate share of risk can be addressed through performance-based ratemaking or other customer protection mechanisms the Commission should reject the Company's IRM. (Vol. 6, Tr 2274.)

A. Staff's Earnings Sharing Mechanism should be adopted, as a performance-based incentive.

The Commission should adopt Staff's recommended excess revenue sharing mechanism as outlined in Staff witness Ryan S. Laruwe direct testimony.

In his direct testimony, Company witness Srikanth Maddipati outlines an IRM Excess Return Sharing Mechanism to provide assurance that the IRM will not result in excess earnings above the reasonable range approved in this case. The mechanism supported by Company witness Srikanth Maddipati provides the Company a ROE range of 10-11% where the Company would not provide any sharing with rate payers. The Company proposes to share 50% of the earnings between 11% and 12% with rate payers and all earnings above 12% be refunded to customers. Company witness Maddipati explains that the Company has no plans or intentions to earn an ROE above its proposed reasonable range and that factors such as weather, economy and cost savings have impacted its recent earnings leading to excess revenues, contrary to Staff and intervenors concerns in previous cases. He states that the proposed mechanism should allay those concerns by Staff and Intervenors. (Vol. 3, Tr 466-466.)

Although Staff is not supportive of the IRM proposed by the Company in this case, Staff found merit in the use of an excess sharing mechanism to address Staff and Intervenors' concerns with the ongoing over-earnings of the Company. (Vol. 6, Tr 2276.) Staff's recommendation to adopt a non-IRM based excess earnings mechanism is not due to the effects that weather, economy, or cost savings have on ROE, although it will protect customers from profit windfalls associated with these factors outside the Company's control. Instead the main reason for recommending the use of this mechanism is to address concerns associated with the managerial decisions to vary authorized spending plans to the benefit of the shareholder during the operation of the projected test year. These decisions to cut spending in key reliability-based programs such as tree trimming, pole inspections, and capital reliability (previously grid modernization) will likely have significant impacts on customer satisfaction and service quality while improving the Company's bottom line. Given the Company's poor reliability performance as outlined by MEC witness Douglas Jester (Vol. 6, Tr 2602), the logic and reasonableness of cutting these key reliability programs is suspect.

Staff's mechanism is designed to marginally disincentivize these decisions through the requirement to return a portion of the excess revenue realized through these decisions be shared with rate payers. Staff's proposed mechanism would also provide customer safeguards from the Company reinvesting excess revenues to lower the realized ROE and avoid excess earnings. This is accomplished by capping the rate base at the authorized amount issued at this order. This would require

that re-investments be subject to prudence review before they could impact refund calculations. Staff's proposed sharing mechanism is outlined in the following table. (Vol. 6, Tr 2276-2278.)

Staff Proposed Excess Revenue Sharing	
ROE	Proposed Sharing
9.75% – 9.95%	No Sharing
9.95% - 10.75%	50/50 Share
>10.75%	75/25 Rate Payer

Staff's mechanism represents a more reasonable approach to excess revenue sharing because the no sharing band is tied to historic cost savings of 2% O&M cost savings claimed by the Company. This 2% savings equates to approximately \$12 million or 20 basis points. Therefore, the mechanism continues to incentivize the Company to continue to find efficiencies. However, above these efficiencies, where the effects of weather, economy, and managerial decisions materially impact ROE, there will be a portion returned to rate payers. (Doc. No. 342, Vol. 6, Tr 2321-2322.)

In rebuttal testimony, the Company argued that Staff witness Laruwe's claim of manipulating earnings is both without merit and lacks "any support" and the Commission should "forcefully discourage" any witness from making such claims. (Vol 3, Tr 449-450.) Regarding the merit and support of Staff's claim, cross-examination by the Company revealed that Staff's discovery response CE-ST-15 clearly outlines the theoretical impact of the Company's managerial decisions on recognized ROE. This discovery response provided a nuanced and balanced approach to providing context for how Company managerial decisions can impact

recognized ROE. (Vol. 6, Tr 2297-2298.) As witness Laruwe stated, “[T]here was no evidence in support of all of the excessive earnings being associated directly with cost savings and economy and weather, but I don't believe that was a statement that they were not in fact contributing answers.” (Vol. 6, Tr 2302.) In other words, Staff believes that in part the excessive earnings may have been due to factors outside the Company’s control, and, in part, due to factors within their control. Staff detailed its reasons for such statements throughout this case. As Staff explained in testimony, Staff’s proposed earnings sharing mechanism could help to correct the disparity between only the Company benefiting from excess earnings, not ratepayers. (Vol. 6, Tr 2299.) Cross-examination reveals that the Staff illustrated how reinvestment in certain categories, not approved by the Commission, may result in elevated ROEs. The Company took issue with the Staff not having sufficient numbers available regarding the under-investment in U-17990 to calculate the exact impact on ROE that resulted in that case, but Staff indicated that was due to failure of the Company to provide the numbers. (Vol. 6, Tr 2305.) The Company should not be allowed to shift the burden of proof in this case.

Not only did witness Laruwe clearly state in testimony that he did not believe that the Company’s redistribution of approved spending was appropriate (in compromising reliability and perhaps contributing to over-earning of its ROE) but Staff’s theory is provided even greater merit and support through the discovery response of Company witness Heidi Myers (Doc. No. 344, Exhibit S-19) which all

but verify that Staff concerns regarding how it chooses to invest funds to boost its ROE are, in fact, warranted and can be inferred from the evidence in the case.

Furthermore, the existence of the underspending in tree trimming and reliability/grid modernization are clearly outlined in Staff witness Laruwe's direct testimony in U-18322. Company Exhibit A-36, outlines the significant reinvestments in 2018 above what was included in rates in U-18322 that the Company is currently seeking recovery of. Company witness's attack on Staff witness' expert analysis and call for punitive measures be taken are unreasonable and inappropriate in the context of a general rate case. (Vol. 3, Tr 449-450.) Staff is encouraged that the Commission has fostered robust (but civil) disagreement, such as in its order and comments related to Case No. U-18419. Staff expects that the Commission continues to believe that a fair dispute is appropriate in a contested case.

As the Commission and ALJ are aware, Staff is in the position that it must rely upon the Company to provide the necessary and accurate information in order to perform a prudence review. To the extent that the Company is unwilling to provide evidence that dispels Staff's claims in rebuttal and instead turns to attacking the integrity of expert witnesses is not proper.

Staff believes that the Commission would also want to be made aware of Company witnesses not being forthcoming with information that can assist in Staff's analysis. As stated by Commissioner Eubanks in a concurring opinion in Case No. U-18419, "[T]he integrity of this Commission's process is dependent on

stakeholder input and transparency so we as Commissioners can make an informed decision that best represents the public interest.” *In re DTE Electric Company request for approval of certificates of necessity*, 4/12/2018 Order, Case No. 18419, Concurrence p. 3. Staff is convinced that Commissioner Eubanks assertion is a belief held by the entire Commission Staff , and that transparency and input are critical to ratemaking.

Thus, Staff brings to the attention of the Commission that Company witness Madipatti made the assertion in sworn testimony in Case No. U-18322, that the Company had in fact increased rate base to the levels authorized in U-17990 (In re Consumers Energy Co, Case No. U-17990, 10/11/2017 Opinion & Order) contrary to Staff’s claim in the U-18322. A review of the Exhibits S-30 and S-31 (Doc. No. 344), submitted in this case, show that this statement was misleading and inaccurate. The Company did not make the capital investments that were included in rates during the U-17990 test year.

In fact, the Company plant additions were approximately \$55 million less than what was included in rates. (Doc. No. 344, Exhibit S-30, line 1.) Staff also notes that when asked directly about Staff’s claim of underspending of capital in U-17990, Company witness Heidi Myers was not able to answer the question but the next day authored discovery that verified Staff’s position. (Doc. No. 326, Vol. 2, Tr 558-559.) Staff is encouraged that it was able to eventually receive the information but would have liked to have had it more readily available from the witnesses.

More importantly, the Company's lack of promised capital investment thwarts the Commission's ability to set reasonable rates, is unacceptable and the Commission should exercise its right to discourage these practices by the Company. If the Company does not cease such practice, the ALJ and Commission may need to consider the merit of allowing the Company to use a projected test year and could revert to the use of historic test year with regulatory lag. As stated in Public Act 286, A utility *may* use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges. The use of projected test years is not mandatory, until the Company can show projections are reasonably representative of the actual investments, the Commission should consider the merit of allowing the Company to use this approach.

Later in his rebuttal testimony, Company witness Maddipati claimed that it is common practice in managing a *dynamic* business to balance over-spending in some programs and under-spending in others, based on emergent priorities as circumstances change throughout the year. The Company must also make these decisions with the best information available at the time, which may not be perfect. (Vol. 3, Tr 551.) Although the Staff does not dispute the need for flexibility and changes in spending during the test year, this need does diminish the Company's obligation to operate reasonably and prudently during the test year. Through cross-examination Staff attempted to better understand this decision-making process referenced in rebuttal testimony through the cross examination of Company witnesses Michael Torrey and Srikanth Maddipati. Staff inquired into who makes

these decisions within the Company to vary spending from authorized amounts in previous rate cases. Witness Torrey testified, upon cross examination, by Staff counsel:

Q. Do you agree that it is reasonable and prudent that the Company to vary distribution capital spending upwards by 96 million -- \$96 million during the U-18322 test year?

A. Yes.

Q. Are you aware of the business decision to underspend versus what was authorized in the reliability distribution capital program?

A. Generally I'm aware that reliability spending was reduced because other spending that was required had to be made.

Q. Would you consider the Company's distribution reliability program a lower priority compared to other capital spent?

A. The Company has to consider a number of variables, not just capital spent, and the decision was made to reduce reliability spending because other spending had to occur.

Q. And could you identify who at the Company was making those decisions?

A. The leadership team.

Both witnesses Torrey and Maddipati stated that these decisions were made at the executive level by employees that had fiduciary obligations to the shareholders of CMS Energy. (Torrey, Doc. No. 326, Vol. 2, Tr 141-143; Madipatti, Doc. No. 327, Vol. 3, Tr 664-665.) Company executives have both a legal and ethical obligation to act in the interest of the shareholders of CMS Energy, with no equivalent obligation to ratepayers. Furthermore, these executives are required to act in the interest of both CMS Energy's gas and electric business thereby potentially subsidizing one

another with the rates authorized by the Commission for each individual business.

Witness Madipatti testified:

When we create budgets and the like, we would say that those would be lined up with how we try to do -- with the case. To the extent that you had something emerge and the Company had to fund it, then yes, in general you're saying you have all the revenue available. [Vol. 3, Tr 663.]

Staff submits that this is an unreasonable and confusing approach to setting reasonable electric rates in this case as electric rate payers, regardless if they are combination customers, are assuming the risk of the gas business. This type of approach by the Company also provides support for the potential use of historic test years in order to stop this cross subsidization in the interest of the shareholders.

Finally, it should be noted that at the executive level, a large amount of the compensation earned by these employees is in the form of stock plans. This is illustrated in the Company's annual P-521 (Rev 12-04) publicly available reports filed at the MPSC annually and is stipulated as a fact in this case by Consumers. (Vol 3, Tr. 665.) To a lesser extent, employees testifying as experts are shareholders. (Vol 3, Tr. 581.)

This compensation creates another level of potential bias where improving the Company's stock performance through varying spending plans would financially benefit these executives. Given the potential conflicts of interest (fiduciary responsibilities and stock compensation) that exist at the executive level, the level of scrutiny of this process and the evidence towards the reasonableness need to be significant. Absent the cooperation of the Company in providing the necessary

witnesses and evidence to scrutinize these decisions, the Commission should once again consider reverting to historic test years to alleviate these concerns.

Although the Company claims that the Staff's analysis of its excessive earnings is without merit and lacks support, the record evidence shows the Staff's concerns are reasonable and supported. Therefore, Staff recommends the ALJ and Commission adopt the excessive earnings mechanism and consider the concerns outlined above in the context of their final order in this case.

XI. Conclusion

Staff recommends that the ALJ and the Commission find that Consumers' total electric revenue sufficiency is \$40.632 million for the projected 2019 test year. Staff recommends that the ALJ and the Commission adopt Staff's lower rate base, return on equity, and operating expenses, as well as Staff's proposed cost of service, rate design, and tariff revisions. Staff's recommendations strike the right balance between Consumers' interests and its ratepayers' interests.

Respectfully submitted,

**MICHIGAN PUBLIC SERVICE COMMISSION
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DATED: November 9, 2018
20134/Initial Brief

U-20134
Initial Brief
Appendix A

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Revenue Deficiency (Sufficiency)

Projected 12 Month Period Ending December 31, 2019

(\$000)

Appendix A

Staff Initial Brief

Case No.: U-20134

Line No.	(a) Description	(b) Source	(c) (d) (e) Total Company		
			Applicant Projection (Rebuttal)	Staff Adjustment	Staff Projection (Initial Brief)
1	Rate Base	Exhibit: A-12 (HJM-42)	\$ 10,682,739	\$ (62,827)	\$ 10,619,912
2	Adjusted Net Operating Income	Exhibit: A-13 (HJM-49)	633,973	13,881	647,855
3	Overall Rate of Return	Line 2 / Line 1	5.93%	0.17%	6.10%
4	Required Rate of Return	Exhibit: A-14 (AJD-1)	6.28%	-0.47%	5.81%
5	Income Required	Line 1 * Line 4	671,046	(53,535)	617,511
6	Income Deficiency/ (Sufficiency)	Line 5 - Line 2	37,073	(67,417)	(30,344)
7	Revenue Multiplier	Exhibit: A-13 (HJM-50)	1.3391	0.0000	1.3391
8	Revenue Deficiency (Sufficiency)	Line 6 * Line 7	49,644	(90,277)	(40,632)
9	U-20102 TCJA Credit A Simultaneously Ceased with New Rates Effective in the Instant Case	Staff Witness Isakson			123,435
10	Net Rate Increase	Line 8 + Line 9			\$ 82,803

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Projected Rate Base

Projected 12 Month Period Ending December 31, 2019

(\$000)

Appendix B

Staff Initial Brief

Case No.: U-20134

Line No.	(a) Description	(b) Source	(c) Total Company			(e) Staff Projection (Brief)
			(c) Applicant Projection (Rebuttal)	(d) Staff Adjustment	(d) Staff Adjustment	
1	Total Utility Plant	Exhibit: A-12 (HJM-44)	\$ 15,797,888	\$ (64,741)	\$	15,733,147
2	Depreciation Reserve	Exhibit: A-12 (HJM-45)	5,860,916	(1,911)		5,859,005
3	Net Utility Plant	Line 1 - Line 2	\$ 9,936,971	\$ (62,828)	\$	9,874,142
4	Retainers & Customer Advances	Exhibit: A-2 (HJM-4)	(58,242)	-		(58,242)
5	Adjusted Net Utility Plant	Sum Lines 3 - 4	9,878,729	(62,828)		9,815,900
6	Working Capital	Exhibit: A-12 (HJM-46)	804,011	-		804,011
7	Total Projected Period Rate Base	Line 5 + Line 6	\$ 10,682,740	\$ (62,828)	\$	10,619,912

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
 Projected Net Operating Income
 for the Test Year Ended December 31, 2019
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Appendix C
 Staff Initial Brief
 Case No.: U-20134

Line No.	(a) Description (Witness)	Revenue				Expenses									NOI		
		(b) Sales Revenue	(c) Wholesale Revenue	(d) Other Electric Revenue	(e) Total	(f) Power Supply Costs	(g) Other O&M Expense	(h) Depreciation & Amort.	(i) R&PP Tax	(j) Other General Taxes	(k) Other (or Local) Taxes	(l) State Income Tax	(m) FIT	(n) Total	(o) NOI	(p) AFUDC	(q) Adjusted NOI
Company Filed																	
1	Operating Income (Initial Filing)	4,270,880	25,491	52,233	4,348,604	2,124,368	596,376	655,409	169,400	30,775	1,299	38,881	110,944	3,727,452	621,152	8,834	629,986
	Revenue	2,546			2,546						4	135	505	645	1,901		1,901
	IT				-			(511)	(48)		1	30	111	(417)	417		417
	HVD - New Business				-			(88)	(32)		0	6	24	(90)	90		90
	Capital Contingency				-			(1,593)	(299)		3	100	376	(1,413)	1,413		1,413
	Marketing				-			(2,235)			4	119	444	(1,669)	1,669		1,669
	Proforma Interest				-						9	315	1,178	1,502	(1,502)		(1,502)
	Interest Synchronization				-						-	-	1	1	(1)		(1)
	Operating Income (Rebuttal - Total Co.)	4,273,426	25,491	52,233	4,351,150	2,124,368	594,141	653,217	169,021	30,775	1,320	39,586	113,583	3,726,011	625,139	8,834	633,973
Staff Adjustments																	
2	Sales Revenue	1,388			1,388						2	74	275	351	1,036		1,036
3	Information Technology (McMillan-Sepkoski)				-			(8,282)			13	440	1,644	(6,185)	6,185		6,185
4	Customer Experience (Fromm)				-			(768)			1	41	153	(574)	574		574
5	Cust. Experience - Marketing and Strategy (Fromm)				-			(1,168)			2	62	232	(872)	872		872
6	Incentive Compensation (Harris)				-			(3,289)			5	175	653	(2,456)	2,456		2,456
7	Cap Ex Adj Impact on Prop. Tax & Depr.				-			(2,679)	(719)		5	180	675	(2,537)	2,537		2,537
8	Proforma Interest (Nichols)				-						(1)	(46)	(172)	(219)	219		219
9	Interest Synchronization (Nichols)				-						(0)	(0)	(1)	-	2		2
10	Total Adjustments	1,388	-	-	1,388	-	(13,507)	(2,679)	(719)	-	28	925	3,458	(12,494)	13,881	-	13,881
11	Staff NOI - Total Company - Test Year (Brief)	4,274,814	25,491	52,233	4,352,538	2,124,368	580,634	650,538	168,302	30,775	1,347	40,511	117,041	3,713,517	639,021	8,834	647,855

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Overall Rate of Return Summary

Projected Capital Structure & Cost Rates

Projected 12 Month Period Ending December 31, 2019

Appendix D

Staff Initial Brief

Case No.: U-20134

Line No.	(a) Description	(b) Source	(c) 13-Month Average (\$000)	(d) % of Permanent Capital	(e) % of Total Capital	(f) Cost Rate	(g) through (i) Weighted Cost			(j) Pre-Tax Basis	
							Permanent Capital	Total Capital	of Debt		
1	Long Term Debt	WP-HJM-116	\$ 6,692,616	47.91%	38.13%	4.47%	2.14%	1.70%	1.70%	1.70%	
2	Preferred Stock	WP-HJM-116	\$ 37,315	0.27%	0.21%	4.50%	0.01%	0.01%		0.01%	
3	Common Equity	WP-HJM-116	\$ 7,240,346	51.83%	41.25%	9.75%	5.05%	4.02%		5.39%	
4	Permanent Capital		\$ 13,970,277	100.00%			7.21%	0.00%		0.00%	
5	Total Short Term Debt	WP-HJM-116	\$ 154,000		0.88%	4.14%		0.04%	0.04%	0.04%	
6	Deferred FIT	WP-HJM-116	\$ 3,322,000		18.93%	0.00%		0.00%		0.00%	
	<u>Deferred JDITC/ITC</u>										
7	Long Term Debt	WP-HJM-116	\$ 50,780		0.29%	4.47%		0.01%	0.01%	0.01%	
8	Preferred Stock	WP-HJM-116	\$ 283		0.00%	4.50%		0.00%		0.00%	
9	Common Equity	WP-HJM-116	\$ 54,936		0.31%	9.75%		0.03%		0.04%	
10	Total Capitalization		\$ 17,552,277		100.00%			5.81%	1.75%	7.19%	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
 Capital Expenditure and Rate Base Adjustments
 Projected 12 Month Period Ending December 31, 2019
 (\$000)

Appendix E
 Staff Initial Brief
 Case No.: U-20134

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Adjustment Description	Total Cap Ex Adj.	Test Year Impacts From Staff Adjustment(s) to Cap Ex Projects				
			Plant Adj.	Accum Depr.	Rate Base	Depreciation	Prop. Tax
1	Distribution - New Business	(7,334)	(3,667)	(56)	(3,611)	(112)	(41)
2	Distribution - Reliability	(66,118)	(40,049)	(824)	(39,225)	(1,221)	(445)
3	Distribution- Demand Failures	(19,608)	(9,804)	(150)	(9,654)	(299)	(109)
4	Distribution Electric Operations Other	(11,310)	(8,577)	(694)	(7,883)	(825)	(95)
5	Total Distribution	(104,370)	(62,097)	(1,723)	(60,374)	(2,457)	(689)
6	Steam Generation Early Retirement 2023	(2,719)	(1,360)	(34)	(1,326)	(67)	(15)
7	IT	(1,284)	(1,284)	(155)	(1,129)	(155)	(14)
8	Total	(108,373)	(64,741)	(1,911)	(62,829)	(2,679)	(719)

Source: WP-SAH-1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Change in Staff Rate Base from Initial Filing to Initial Brief

Projected 12 Month Period Ending December 31, 2019

(\$000)

Appendix F

Staff Initial Brief

Case No.: U-20134

(a) Line	(b) Description	(b) Change in Rate Base	(c) (d) (e) (f) Initial Filing				(g) (h) (i) (j) Initial Brief			
			Cap Ex	Plant	A/D	Rate Base	Cap Ex	Plant	A/D	Rate Base
1	Adopt Company Concession on AG HVD Cap Ex Adj.	(2,784)	-	-	-	-	(2,872)	(88)	(2,784)	
2	Rate Base Reduction - Staff Initial Filing to Brief	(2,784)	-	-	-	-	(2,872)	(88)	(2,784)	
Description		Rate Base	Source							
3	Initial Filing - Rate Base (Staff)	10,622,696	Exh. S-1, Sch. A-1							
4	Change (Company Rebuttal Concession Above)	(2,784)	Appendix F, Initial Brief							
5	Initial Brief - Rate Base (Staff)	10,619,912	Appendix B, Initial Brief							

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Staff Position

Projected 12 Month Period Ending December 31, 2019

(\$000)

Appendix G

Staff Initial Brief

Case No.: U-20134

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
<u>Walk from Consumers Electric Revenue Deficiency (Rebuttal) to Staff Initial Brief</u>							
Line	Description	Source	Rate Base	Pre-Tax			Revenue Requirement Impact
1	Company Revenue Deficiency (Rebuttal - Total Co.)	Consumers Rebuttal, Schedule A-163 (HJM-66)					\$ 49.6
2	Change in Rate base	Appendix E / Exhibit A-147 (AJD-12)	(62,829)	7.82%			(4.9)
3	Change in rate of return	Appendix A / (Appendix D less A-147 (AJD-12))	10,619,912	-0.63%			(67.0)
4	Sales Revenue	Appendix C, line 10					(1.4)
5	O&M adjustment	Appendix C, line 10					(13.5)
6	Depreciation adjustment	Appendix C, line 10					(2.7)
7	Property Tax adjustment	Appendix C, line 10					(0.7)
8	Total Staff adjustments (rev. req. impact)	Appendix A, line 8					(90.2)
9	Rounding						(0.1)
10	Staff Initial Brief - Revenue Sufficiency (Total Co.)	Appendix A, line 8					\$ (40.6)

<u>Walk from Staff Initial Filing to Staff Initial Brief Revenue Deficiency</u>								
Line	Description	Source	Initial Filing	Initial Brief	Change	Pre-Tax / Rate Base		Revenue Requirement Impact
11	Initial Filing - Staff Revenue Sufficiency (Total Co.)	Exh. S-1, Sch. A-1						\$ (37.6)
12	Change in Rate base	Exh. S-1, Sch. A-1 / App. A / Exhibit A-147 (AJD-12)	10,622.7	10,619.9	(2.8)	7.82%		(0.2) ¹
13	Change in Depreciation and Property Tax							(0.1)
14	Add Staff Marketing Adjustment not in Staff's Initial Filing Revenue Requirement							(3.4)
15	Change in Cost of Capital	Appendix D	7.1851%	7.1920%	0.0069%	10,619.9		0.7
16	Initial Brief - Staff Revenue Deficiency (Total Co.)	Appendix A, line 8						\$ (40.6)

Notes:

(1) See Appendix F

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DE ANN PAYNE

Subscribed and sworn to before me
This **9th** day of **November, 2018**.

Pamela A. Pung, Notary Public
State of Michigan, County of Clinton
Acting in the County of Eaton
My Commission Expires: 5-7-2025