STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

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DANA NESSEL
ATTORNEY GENERAL

February 21, 2019

Ms. Kavita Kale
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Dear Ms. Kale:

Re: <u>MPSC Case No. U-20276</u>

Enclosed find the **Attorney General's Direct Testimony and Exhibits** and related Proof of Service.

Sincerely,

Michael Moody

Digitally signed by Michael Moody
Date: 2019.02.21 15:35:02 -05'00'

Michael E. Moody
Assistant Attorney General

c All Parties

PROOF OF SERVICE - U-20276

The undersigned certifies that a copy of the ***Attorney General's Direct Testimony and Exhibits*** was served upon the parties listed below by e- mailing the same to them at their respective email addresses on the 21st of February 2019.

Michael Moody Digitally signed by Michael Moody Date: 2019.02.21 15:35:29 -05'00'

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-20276

In the matter of the application of)
UPPER PENINSULA POWER COMPANY)
for authority to increase retail electric rates.)

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

February 21, 2019

Qualifications

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Sebastian Coppola. I am an independent business consultant. My office is at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than thirty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission (MPSC or Commission) and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases, and other proceedings. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings and power plant cost analysis. I have also supported other witnesses in testimony before the MPSC in various rate setting and other regulatory proceedings.

Q. WHAT EXPERIENCE DO YOU HAVE WITH ELECTRIC UTILITIES?

A. I have performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, cost allocations, cost of capital, cost of service and rate design, various cost tracking mechanisms and integrated resource plans. In addition, I have performed analyses of power costs and filed testimony in power supply cost recovery mechanisms, including reconciliation of annual power supply costs.

In my position as Senior Vice President of Finance at MCN Energy Group, I also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, I was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, I was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY AGENCIES.

A. Here is a partial list of the most recent regulatory cases in which I have participated:

- Filed testimony on behalf of the Michigan Attorney General in DTE Electric 2018 electric rate Case U-20162 on several issues, including O&M expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Gas Division in case U-20287.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 Power Supply Cost Recovery (PSCR) reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several Gas Cost Recovery (GCR) and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas and Coke Company's (Peoples Gas) main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.

Appendix A elaborates further on my qualifications in the regulated energy field.

Prepared Direct Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the AG to perform an independent analysis of Upper Peninsula Power Company's ("Company" or "UPPCO") Electric Rate Case filing U-20276. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I am addressing the following major topics in this case:

1. The proposal to include the Escanaba Hydro Facility in rate base
2. The calculation and refund of excess deferred taxes
3. The revenue credit of approximately $4.3 million agreed to in Case No. U-17564
4. The pension plan funding revenue credit of $390,000 agreed to in Case No. U-17895
5. The expense for the Supplemental Employee Retirement Plan
6. Adjustments for errors related to inclusion of interest expense in operating income and the calculation of funds used during construction ("AFUDC")
7. The Company's Cost of Capital and Working Capital
8. Rate Design Issues

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of UPPCO's rate case filing. The narrow focus of my testimony is, instead, a consequence of focusing on priority issues within the available resources.

Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit AG-1 UPPCO Discovery Response – Escanaba Hydro Facility History
2. Exhibit AG-2 UPPCO Discovery Response – Escanaba Facility Revised Costs
3. Exhibit AG-3 UPPCO Discovery Response – Escanaba Facility Future Costs
4. Exhibit AG-4 UPPCO Discovery Response – Excess Deferred Taxes Calculation
5. Exhibit AG-5 UPPCO Discovery Response – Excess Deferred Taxes Issues
6. Exhibit AG-6 UPPCO Discovery Response – Excess Deferred Taxes Amortization
7. Exhibit AG-7 UPPCO Utility Assets Remaining Depreciable Life
8. Exhibit AG-8 Calculation of Corrected Excess Deferred Taxes Amortization
9. Exhibit AG-9 UPPCO Discovery Response – Interest and AFUDC Errors
10. Exhibit AG-10 Calculation of Adjustment to Working Capital and Deferred Taxes
11. Exhibit AG-11 Overall Cost of Capital
12. Exhibit AG-12 Cost of Common Equity-Summary
13. Exhibit AG-13 Cost of Common Equity-DCF
14. Exhibit AG-14 Cost of Common Equity-CAPM
15. Exhibit AG-15 Cost of Common Equity-Risk Premium
16. Exhibit AG-16 Peer Group Market to Book Ratios
17. Exhibit AG-17 Peer Group Debt and Equity Capitalization
18. Exhibit AG-18 Electric ROE Decisions by Regulatory Commissions
19. Exhibit AG-19 UPPCO Common Equity Balance – October 2018 & Equity Plans
20. Exhibit AG-20 Goodwill-Related Deferred Tax Assets in the Capital Structure
21. Exhibit AG-21 UPPCO Discovery Response – Capital Structure Misc. Adjustments

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.

A. The Company filed for a base rate increase of approximately $10 million. Based on my analysis of the Company's case, I have reached the following summary conclusions and recommendations:

1. I recommend that the Commission reject the Company's proposal to transfer the Escanaba Hydro facility assets of approximately $7.1 million from non-utility operations to utility rate base. Related to this recommendation, the Commission should remove $2.4 million of projected revenues and $1.3 million of projected expenses from the Company's rate case filing.

2. I recommend that the Commission should adjust the Company's calculated excess deferred tax liability from $4.7 million to $11.3 million, and order the Company to begin to refund the portion of the excess deferred taxes pertaining to 2018 in 2019 as a separate refund credit on customer bills from the amount of excess deferred taxes pass-through included in base rates.

3. I recommend that The Commission reject the Company's proposal to reduce the annual revenue credit to $2.6 million, and reinstate it to the approximately $4.3 million agreed to in Case No. U-17564.

4. I recommend that the Commission reinstate the $390,000 revenue credit included in Case No. U-17895 which pertains to the ERISA-required incremental pension plan funding.

5. I recommend that the Commission remove the $11,700 expense related to Supplemental Employee Retirement Plan

6. I recommend that the Commission remove from the Company's adjusted operating income the improper inclusion of $300,000 of interest expense and correct an error of $515,600 in the calculation of AFUDC. Combined these amounts increased the projected adjusted operating income by $815,600.

7. I recommend that the Commission increase the Company's working capital projection to remove the excess deferred tax refund liability of $4.2 million and instead include $10.5 million of deferred tax refund liability in the capital structure.

8. I recommend an authorized rate of return on equity of 9.75% and a capital structure with 53.79% debt and 46.21% equity capital. I also recommend that the Commission remove the deferred tax assets of approximately $9 million related to tax goodwill from the deferred income taxes balance in the capital structure.

9. I recommend that the Commission should reject the Company's proposed increase of the monthly customer charge for Residential customers, and moderate the increase in the monthly customer charges for small and medium-size commercial customers.

The result of these adjustments reduces the Company's proposed revenue deficiency by $6.5 million to $3.5 million. Therefore, I recommend that the Commission not grant any rate increase above $3.5 million in this rate case. It is also possible that during the rate case briefing process the Attorney General may adopt positions taken by Staff and other parties which may change the amount of revenue deficiency I have identified.

The remainder of my testimony provides further details and support to these summary conclusions and recommendations.

<u>Escanaba Hydro Power Facility</u>

Q. **PLEASE BRIEFLY DESCRIBE THE ESCANABA HYDRO POWER FACILITY.**

A. Beginning on page 8 of his direct testimony, Company witness Gradon Haenel describes the Escanaba Hydro Power Facility ("Escanaba Facility") as consisting of three water dams with a total nameplate generating capacity of 9.2 Megawatt ("MW"). The Escanaba facility serves only one customer, Verso Corporation, and is not connected to the UPPCO power distribution system. Although the Company serves this customer under an MPSC-approved contract, the Escanaba facility has been operated as a non-utility business with its assets, revenue and expenses excluded from the normal rate making process. A discovery response received from the Company and included in Exhibit AG-1 confirms this fact.

Q. **HAS THE COMPANY NOW PROPOSED TO INCLUDE THE ESCANABA FACILITY AS A FULLY REGULATED UTILITY ASSET?**

A. Yes. On page 10 of his direct testimony, Mr. Haenel proposes to include all revenue, capital costs, depreciation, and operating costs for the Escanaba Facility with fully regulated utility assets of the Company. As such, the Company has included \$7.1 million of net assets in the projected rate base, \$2.4 million of projected revenue and

$1.3 million of expenses. Exhibit A-41 (GRH-3) details these items and related amounts.

Q. **WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSAL TO INCLUDE THE ESCANABA FACILITY AS A FULLY REGULATED UTILITY ASSET?**

A. The proposal should be rejected. The Company has been operating this facility for several years as a non-utility investment with all benefits of operating the facility accruing solely to the Company and its shareholders. The facility is not connected to the Company power distribution system and the Company's utility customers would gain no benefit from including this facility as a fully regulated utility asset. For utility customers, there would be no financial or operating benefits, but only the potential for significant financial risks and higher electric rates.

It appears that the Company foresees difficulties in profitably operating the facility and is attempting to burden its utility customers with potentially significantly higher costs. According to Exhibit A-41, the Company's current sales contract with Verso Corporation has been forecasted to generate approximately $1.1 million in revenue. The Company has forecasted that total expenses to operate the facility, including depreciation and property taxes, will be $1.3 million. Thus, there would be a projected loss of approximately $200,000 to operate the facility during the 2019 projected test year.

To overcome this loss and make the potential transfer more appealing, the Company has unrealistically assumed that it would be able to more than double the revenue received from Verso Corporation by amending the sales contract. Exhibit A-41 shows that the Company has assumed it would be able to increase revenue from $1.1 million to $2.4 million. In discovery, the Company was asked if it has a written commitment from the customer to be able to increase the sales revenue. The response, which is included in Exhibit AG-2, states that the Company has no such commitment and is discussing the matter with the customer. In other words, there is no valid basis to rely on any additional revenue being received from the sales contract.

Customers also would be burdened by the inclusion of $7.1 million in rate base and the related pre-tax return of $562,000 on rate base.[1] Although in response to discovery, the Company has revised its proposal and has reduced the net book value and depreciation expense significantly, there is still a revenue shortfall of $263,000, which would be recovered from utility customers, in addition to the return on rate base, if Verso refuses to amend the sales contract and pay for the full service cost of the facility.[2] This revised cost scenario would still be a bad deal for utility customers, if the Commission were to approve the transfer of the facility from non-utility investments to utility rate base and allow full rate recovery.

[1] Rate base addition of $7.1 million x pre-tax cost of capital of 7.9117% from Exhibit A-14, Schedule D1.
[2] UPPCO response to discovery requests 5-Staff-UPPCO-2, 5-Staff-UPPCO-4, and 6-Staff-UPPCO-8.

Q. **ARE THERE OTHER POTENTIAL COSTS LOOMING IN THE FUTURE WITH THE ESCANABA FACILITY, WHICH COULD FURTHER BURDEN RATEPAYERS?**

A. Yes. In response to discovery, the Company has stated that FERC-mandated and safety-related improvements to some portions of the facility would require capital investments ranging from $2.9 million to $4.1 million. Moreover, if in the future, the facility were determined to be uneconomical to operate and it would need to be decommissioned, the costs to decommission the facility could range from $30.9 million to $64.1 million. Exhibit AG-3 includes the discovery responses with the future cost estimates provided by the Company.

These potential future costs present considerable and unacceptable financial exposure to the utility customers of UPPCO that would likely translate into higher electricity rates.

Q. **WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

A. It is rather apparent from the discussion above that there is no likely beneficial outcome to utility customers from the transfer of the Escanaba facility to utility operations and the full rate recovery of operating and capital costs. On the contrary, there are significant adverse cost increases and higher electricity rates that would surely result from this proposed transfer.

Therefore, I recommend that the Commission reject the Company's proposal to transfer the assets of the Escanaba Facility from non-utility to utility operations. The

Commission should also remove the rate base additions of $7,062,315, the projected revenue addition of $2,362,719, and the projected expenses of $1,268,125 from the Company's rate case filing related to the Escanaba Facility.

Excess Deferred Taxes & Refunds

Q. **PLEASE DESCRIBE THE COMPANY'S CALCULATION OF EXCESS DEFERRED TAXES AND THE PROPOSED PASS-THROUGH TO CUSTOMERS.**

A. Beginning on page 35 of his direct testimony, Company witness Nicholas Kates discusses the calculation of the excess deferred taxes resulting from the Tax Cut and Jobs Act of 2017 ("TCJA"). Mr. Kates describes the pass-through of $938,469 in excess deferred taxes in this rate case through a reduction in tax expense in Exhibit A-13, Schedule C8. The Company determined this amount by dividing the total excess deferred tax liability of $4,692,346 over five years.

Additionally, in his direct testimony, Mr. Kates describes that the $4.7 million of excess deferred taxes translates to a total refund amount of $6.3 million which will be passed through to customers. He determined this refund amount by applying the tax multiplier gross-up factor of 1.3466 to the $4.7 million excess deferred taxes liability balance. Mr. Kates further notes that the $4.7 million net excess deferred taxes liability balance consists of three specific items.

First, it includes $6.9 million of excess deferred taxes pertaining to plant assets. The pass-through to customers of these excess deferred taxes must comply with the tax normalization requirements of the Internal Revenue Code. These items also referred as Protected Excess Deferred Taxes must be passed through to customers over the average life of the underlying plant assets using either the Average Rate Assumption Method ("ARAM") or the Reverse South Georgia Method ("RSGM").

Second, Mr. Kates discusses the Company's inclusion of excess deferred tax assets in the amount of $6.7 million related to Goodwill costs. These excess deferred tax assets almost entirely offset the $6.9 million of protected excess deferred taxes pertaining to plant assets.

Third, there are excess deferred taxes pertaining to other book to tax timing differences (Schedule M items) which amount to $4.5 million. This amount plus the $0.2 million difference in the first two items totals to the $4.7 million. Page 1 of Exhibit AG-4 includes the support schedule provided by the Company detailing the components of the $4.7 million in excess deferred taxes. Page 2 of the exhibit aggregates the excess deferred taxes into the three components: Protected Plant-Related, Non-Protected Tax Goodwill and Non-Protected Other Items.

Q. **WHAT IS YOUR ASSESSMENT OF THE COMPANY'S CALCULATION OF EXCESS DEFERRED TAXES AND PROPOSED PASS-THROUGH TO CUSTOMERS.**

A. There are three main issues with the Company's approach. First, the inclusion of goodwill-related excess deferred tax assets to reduce the excess deferred liabilities from the other two items is unacceptable. Second, the Company's amortization of the net excess deferred tax liability over five years is convoluted and problematic. Third, the Company proposes to pass-through one-fifth of the excess deferred taxes liability with new rates established in this rate case. This approach avoids the refunding to customers of the excess deferred tax amortization pertaining to the year 2018. I will discuss each of these issues below.

Q. **PLEASE EXPLAIN THE PROBLEM WITH INCLUDING EXCESS DEFERRED TAX ASSETS RELATED TO GOODWILL IN THE CALCULATION OF THE NET EXCESS DEFERRED TAXES LIABILITY OWED TO CUSTOMERS.**

A. In conjunction with the acquisition of UPPCO by Balfour Beatty Infrastructure Partners L.P. ("BBIP"), Upper Peninsula Power Holding Company ("UPPHCO") and related entities from Integrys Energy Group, Inc. ("Integrys") during 2014, UPPHCO recorded book goodwill for a certain amount over the assets held by its subsidiary UPPCO. However, according to the Company's responses to discovery, UPPCO also recorded certain goodwill costs on its books.

In response to discovery question 3-AG-UPPCO-54 and Staff data request BAW_2-3, the Company stated that the amount of goodwill costs on the books of UPPCO (Regulated Tax Goodwill) was created by the new owners' election under IRS Section 338(h)(10). By making this election, the Company was able to write-up the tax basis of the assets to an amount equivalent to the acquisition price for UPPCO in order to depreciate those assets for tax purposes at the higher tax basis. According to the discovery responses "Within its regulated operations this resulted in creation of a tax goodwill asset [related] due to certain acquired regulated book assets not being considered assets for income tax purposes." The discovery responses are included in Exhibit AG-5.

In ratemaking and establishing customer rates, the Company does not get to recover any amount of goodwill costs. Therefore, any other costs or items related to the goodwill asset should not be including in the ratemaking process. Particularly in this situation, the excess deferred tax assets pertaining to the tax goodwill should not be used to offset excess deferred taxes for other items that are part of ratemaking. As shown on page 2 of Exhibit AG-4, the Company used the $6,640,594 of excess deferred tax assets related to goodwill to arrive at the net excess deferred tax liability of $4,692,346. When excluding the goodwill-related excess deferred tax assets, the correct amount of excess deferred taxes to be refunded to customers is $11,332,943 before gross-up, and $15,260,941 after gross-up to a revenue refunding level.

Q. **WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

A. In its response to Staff data request BAW_2-3, the Company states that in its prior rate case, Case No. U-17895, the Company had also included the deferred income tax asset related to goodwill as part of UPPCO's regulated operations. The fact that the Company has included the deferred tax asset in this and its prior rate case does not change the nature of the asset or legitimize its inclusion in ratemaking. Due to the complexity of this issue and the lack of clear explanations, it is not surprising that no party in Case No. U-17895 addressed the issue.

However, it is abundantly clear now that the deferred tax asset like the underlying tax goodwill asset does not belong in the ratemaking process in setting rates for UPPCO's customers. Therefore, I recommend that the Commission remove all deferred income tax assets related to the Tax Goodwill asset from this rate case and future rate cases.

With regard to the appropriate excess deferred tax liability, the Commission should approve the amount of $11, 332,943 (pre gross-up) instead of the Company's proposed $4,692,346. Later in my testimony, I will discuss the removal of remaining goodwill-related deferred tax assets from the capital structure in the calculation of the overall cost of capital.

Q. **PLEASE EXPLAIN THE PROBLEMS WITH THE COMPANY'S PROPOSAL TO REFUND THE EXCESS DEFERRED TAXES OVER A FIVE-YEAR PERIOD.**

A. As stated earlier, the Company has proposed to refund its calculated net excess deferred taxes over five years and has included the amount of $938,469 as a reduction to income taxes in this rate case. In discovery, the Company was asked to explain the basis for the

5-year amortization and how this amortization period complies with tax normalization requirements of the IRS Tax Code, and specifically the ARAM rule.

In response to the first question, the Company stated that it selected the 5-year amortization period as a way to partially offset the rate increase filed in this rate case. With regard to the second question on compliance with the ARAM rule, the Company stated that in discussions with its independent auditor determined that the 5-year amortization approach would not create a normalization violation. Exhibit AG-6 includes the Company response to the discovery questions.

Although, the Company's desire to mitigate the increase in customer rates potentially emanating from this rate case is understandable, it is misguided and unnecessary. As explained later in my testimony, the refund of the proper amount of excess deferred taxes for 2018 in 2019 and the inclusion in base rates of a similar amount of excess deferred taxes will go a long way toward mitigating any increase in rates from this rate case. In fact, the beneficial impact will be nearly twice the amount proposed by the Company.

The response provided by the Company to amortize the excess deferred taxes over a 5-year period is also troubling. First of all, it does not explain how the Company and its auditor reached the conclusion that the amortization over five years complies with the ARAM rule. Based on information filed by the Company in this rate case, I have determined that the average remaining life of the Company's depreciable utility assets is approximately 18 years. Exhibit AG-7 provides this calculation. A more detailed calculation by specific asset class, which could not be done here from the available information, could determine that the average life of the plant assets is possibly even longer than 18 years.

In discovery question 3-AG-UPPCO-54a (included in Exhibit AG-5), the Company was asked to provide the specific amortization period for the "protected" items, but responded that it had not prepared this calculation. Given that under the deferred tax normalization rules, the Company cannot amortize the excess deferred taxes pertaining to the protected plant assets any faster than the remaining life of those assets, it is perplexing how the Company can be compliant to the IRS normalization rules. One possible way that perhaps the Company has contemplated is to create on its books a reserve account with an over-refunded balance during the first five years and a work down of that balance over several years as the protected excess deferred taxes are amortized over the 18-year period or longer. This would be a very convoluted process that would last several years, and ultimately is unnecessary.

Q. **WHAT APPROACH DO YOU PROPOSE TO AMORTIZE THE PROTECTED AND NON-PROTECTED COMPONENTS OF EXCESS DEFERRED TAXES?**

A. As discussed earlier, there are two components to the excess deferred tax liability after excluding the goodwill deferred tax assets. The first component is the excess deferred taxes pertaining to protected plant assets. As shown on page 2 of Exhibit AG-4, this amount is $6,857,018. I propose to amortize this portion over the 18-year remaining life of the utility assets as calculated in Exhibit AG-7. If in rebuttal testimony, the Company presents a more precise amortization period, that period could be used. Based on my calculation, the annual amortization amount of the protected excess deferred tax liability is $380,945, and the revenue equivalent amount to refund to customers after tax gross-up is $512,981.

The second component of the excess deferred tax liability for the non-protected items is $4,474,925. With regard to this portion, the Commission has full discretion to choose any amortization period to pass this amount to customers. For example, it could choose to order the Company to refund the entire amount in a lump sum during 2019 or over several future years. To minimize the impact on the Company's cash flow, and still provide a meaningful and timely pass-through of this tax benefit to customers, I propose a 10-year amortization. Thus, the annual amortization for this portion of the excess deferred taxes is $447,593, and the revenue equivalent amount to refund to customers after tax gross-up is $602,728.

It is more likely than not that the 10-year amortization period would match closely to the period that the Company would have paid this amount of taxes to the U.S. Treasury if the federal tax rate had remained at 35% and that tax rate had been applied to the annual unwinding of book to tax timing differences. In discovery, the Company was asked to provide information on the life of these timing differences, but in response stated that it had not performed this analysis.[3] However, the 10-year amortization period compares favorably with the amortization period for non-protected excess deferred tax liabilities

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[3] UPPCO response to 3-AG-UPPCO-53d included in Exhibit AG-6.

proposed by many of the other Michigan utilities under the jurisdiction of the Commission.

For the two components, I recommend a combined annual amortization amount of $828,538, which translated to a revenue refund to customers of $1,115,709 after tax gross-up.

Q. **PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO PASS-THROUGH THE EXCESS DEFERRED TAXES TO CUSTOMERS.**

A. According to the direct testimony of Mr. Kates, the Company has included $938,469 as a reduction to income taxes on line 10 of Exhibit A-13 (NEK-7), Schedule C8. After the tax gross-up this amount translates to a reduction of $1,263,743 in the revenue deficiency calculated by the Company in this rate case. By reducing the revenue deficiency, the Company is proposing in effect to pass the $1.3 million to customers through new base rates established in this rate case.

Q. **DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE THE PASS-THROUGH OF THE EXCESS DEFERRED TAXES ONLY THROUGH BASE RATES GOING INTO EFFECT IN 2019?**

A. No. The Company's proposal does not address, and in fact delays, the refund of excess deferred taxes owed to customers for the year 2018. The lower tax rates under the TCJA went into effect in January 2018. The excess portion of the deferred taxes between 35% and 21% not payable to the U.S. Treasury began to accumulate in 2018, and as shown in

Exhibit AG-8 the refundable amount is more than $1.1 million. Due to the complexities of calculating the excess deferred taxes (Tax Refund Calculation C), the Commission allowed the utilities under its jurisdiction to delay filing the calculation of the excess Tax Refund Calculation C until October 1, 2018. The Commission also permitted utilities that filed a new rate case prior to October 1, 2018 to use the rate case for the determination of Calculation C. This was the option chosen by UPPCO.[4]

However, the fact that the required filing of the Tax Refund Calculation C was delayed into the later part of 2018 does not mean that customers should not receive the tax benefits for 2018 soon after the Commission approves the annual excess deferred taxes refund amounts owed to customers. For example, in this rate case, the Commission is likely to issue a rate order on or about August 21, 2019.[5] There is no reason why the Commission cannot order the Company to refund the gross-up amount of excess deferred taxes of $1,115,709 pertaining to the year 2018 as a separate Tax Credit C negative surcharge on customers' bills, similar to what was done for Tax Credit A and B. Additionally, the Commission would include the same amount of $1,115,709 pertaining to the projected 2019 test year in base rates to continue into future years until the Company files its next rate case.

By refunding the 2018 portion of the excess deferred taxes in 2019 and including the 2019 amount in base rates, customers would receive a more immediate benefit to

[4] Case No. U-18494, MPSC order dated February 22, 2018.
[5] Stipulation and Agreement Regarding Schedule Change filed by UPPCO in Case No. U-20276.

mitigate the increase in base rates from this rate case. From a cash flow viewpoint, the Company is no worse off than if the federal tax rate had not changed and those taxes would have been paid to the U.S. Treasury. In fact, by delaying the refund to customers of the 2018 amount until 2019, the Company had the benefit of holding on to that cash for an extra year, whereas it would have paid those deferred taxes to the U.S. Treasury in 2018.

Q. **SHOULD THE COMPANY FOLLOW CERTAIN PROCEDURES GOING FORWARD TO ENSURE THAT THE EXCESS DEFERRED TAXES OWED TO CUSTOMERS ARE FULLY REFUNDED IN RATES?**

A. Yes. The amount of excess deferred taxes owed to customers can change from year to year due to plant retirements and other adjustments made to the underlying assets in the course of business. To ensure that the full and correct amount of excess deferred taxes are passed through to customers in future years, it is necessary to keep track of the excess deferred tax amounts refunded, or passed through to customers, versus the amount owed to customers.

In order to keep track of the actual annual excess deferred taxes versus the amount estimated for setting base rates or refunded through a credit, the Commission should require the Company to record either a deferred regulatory asset or a deferred liability for the difference in the two amounts. Additionally, The Commission should direct the Company to file an annual letter under this rate case docket reporting the annual difference and the cumulative asset or liability balance in the regulatory account. The

Commission should also order the Company that in subsequent rate cases, the Company should use the balance in the regulatory account to adjust the future excess deferred tax amount reflected in new rates.

Q. **WHAT IS YOUR OVERALL RECOMMENDATION WITH REGARD TO THE EXCESS DEFERRED TAXES AND THE PASS-THROUGH TO CUSTOMERS OF THOSE TAX BENEFITS?**

A. I recommend that the Commission remove the excess deferred tax assets relating to Tax Goodwill from the calculation of the excess deferred taxes to be refunded to customers. I recommend that the Commission establishes the total refund liability at December 31, 2017 at $11,332,943 before tax gross-up, and $15,260,941 after tax gross-up.

I further recommend that the protected portion of the excess deferred taxes be amortized over a period of 18 years, unless in rebuttal testimony the Company is able to establish a more precise amortization period. I recommend that the non-protected portion of the excess deferred taxes be amortized over a 10-year period, as a reasonable period that balances both the Company's and customers' interests.

Therefore, I recommend that in total the Commission should order the Company to refund to customers the tax gross-up amount of $1,115,709 of excess deferred taxes for 2018 as a Tax Credit C negative surcharge over the 12-month period beginning within 30 days after a Commission order in this rate case. Furthermore, I recommend that the Commission replace the Company's excess deferred tax credit of $938,469 included as a reduction of income taxes in Exhibit A-13 (NEK-7), Schedule C8, with the credit amount of $828,536 that I have calculated in Exhibit AG-8. This amount when grossed up for the tax multiplier is equivalent to a reduction of $1,115,709 in the revenue deficiency and the base rates of the Company.

I also recommend that the Commission order the Company to establish a deferred regulatory account to track the actual excess deferred taxes amortized to expense annually versus the amount estimated in rates, or refunded, with the balance of the account to be reflected in future rates. Furthermore, the Commission should direct the Company to file a letter under this rate case docket reporting the annual activity in the regulatory account.

Revenue Credit U-17564

Q. **PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSAL TO REDUCE THE $4.3 MILLION REVENUE CREDIT ESTABLISHED IN CASE NO. U-17564.**

A. As stated beginning on page 4 Mr. Haenel's direct testimony, the Company agreed to a $26 million revenue credit as part of the settlement agreement approved by the Commission in Case No. U-17564, which authorized the transfer of ownership of UPPCO to BBIP and related entities. The $26 million revenue credit went into effect in 2016 in conjunction with the Company's projected test year in rate case No. U-17895.

The $26 million was annualized over a six year period with an annual revenue credit of $4,333,333 beginning in 2016 and continuing for the subsequent five years.

In this rate case, the Company seeks to reduce the $4,333,333 annual revenue credit applicable to 2018 through 2021 to $2,584,802. The calculations performed by the Company to arrive at this new revenue credit amount are shown in Exhibit A-40 (GRH-2). On page 5 of his direct testimony, Mr. Haenel justifies this revision to the revenue credit as an updated calculation to recapture the actual revenue deficiency experienced by the Company in 2016 and 2017 when it did not earn the authorized return of 10% approved by the Commission in Case No. U-17895.

Q. **DO YOU AGREE WITH THE COMPANY'S PROPOSED REDUCTION TO THE REVENUE CREDIT?**

A. No. First of all, the Company agreed in Case No. U-17564 to reduce its future revenue requirement by $26 million. Second, in Case No. U-17895, the Company agreed to pass-through the $26 million as a revenue credit over a six year period. There is no dispute about these facts. The Company now seeks to reduce the revenue credit for the remaining four years (2018-2021) from $4,333,333 to $2,584,802, or approximately $7 million in total, by claiming that it did not earn up to the authorized return level of 10% in 2016 and 2017, and therefore the Company should retain this $7 million amount.

The Company's proposal should be rejected by the Commission. It amounts to retroactive ratemaking. Nothing in the settlement agreement or Commission order indicated that the $26 million revenue credit was subject to the Company earning its authorized rate of return. The Company has no valid or supportable argument to expect the Commission to approve such a proposal. Once the Commission has established and has approved the Company's rate base, the return on rate base, revenue deficiency, customer rates and other aspects of a rate case, it is the responsibility of the Company to achieve or surpass the authorized return.

There is no going back to historical years and attempt to apply future revenue credit commitments to those historical years, because the Company happened to under-earn its authorized return in those years. For the Commission to approve such as proposal would be prohibited retroactive ratemaking.

Q. **WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

A. The Company has made an invalid and inappropriate proposal to reduce its commitment for the revenue credit agreed to Case No. U-17564 and subsequently implemented in Case No. U-17895.

I recommend that the Commission reject the Company's proposal and instead include the full amount of revenue credit of $4,333,333 in calculating the Company's total revenue deficiency in this rate case.

Pension Plan Funding Revenue Credit U-17895

Q. **PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSAL TO REMOVE THE $390,000 REVENUE CREDIT ESTABLISHED IN CASE NO. U-17895.**

A. According to the Commission order in Case No. U-17895, the Commission accepted the Company proposal in that case to provide a revenue credit of $390,000 as a compromise position to compensate customers for the Company's recovery of costs related to higher pension assets.[6] The Commission order summarizes the positions of the parties, and especially the position of the Staff, on how much pension expense and related pension costs should be recovered in rates by the Company. The Staff argued that the Company should not be allowed to recover a return on $27.7 million of regulatory costs that were part of the $59 million in the deferred pension regulatory asset. These costs pertained to the ERISA requirement that the pension plan funding be increased with the transfer of the UPPCO retirement plan in conjunction with the acquisition of the Company by BBIP and related entities.

On page 36 of the order, the Commission stated:

> Having made the above arguments, UPPCo offers "that a compromise would be in the public interest. . . . UPPCO proposes as a compromise an additional revenue credit to alleviate any concerns regarding residual rate impact to customers associated with the ERISA required pension plan top-up which occurred prior to the 2014 sale of the business. . . . UPPCO is willing to increase the revenue credit amount by $390,000 for the 2016 test year until December 31, 2021."

[6] MPSC Case No. U-17895, Commission order dated September 8, 2016 at page 32.

The Commission accepted UPPCO's offer of compromise and included the $390,000 as a revenue credit in determining the total revenue deficiency in Case No. U-17895.

Through the direct testimony of Mr. Kates, the Company now proposes to remove the revenue credit on the basis that pension expense for the projected test year is below the $1.7 million level established in the pension expense tracker. However, the $390,000 revenue credit was not related to the pension expense tracker established in Case No. U-17895. The Commission order is quite clear by quoting the Company in its own words that the revenue credit was offered to alleviate the impact on customer rates of the additional pension plan funding required by ERISA.

The order is also very clear that the $390,000 revenue credit would continue until December 31, 2021. Therefore, it is perplexing why the Company would renege on its own promise to provide this revenue credit in this rate case and through the end of 2021.

Q. **WHAT IS YOUR RECOMMENDATION?**

A. The Commission should disregard the Company's removal of the revenue credit and include the $390,000 in the calculation of the total revenue deficiency.

<u>Supplemental Retirement Plan Expense</u>

Q. **PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED EXPENSE FOR THE SUPPLEMENTAL RETIREMENT PLAN.**

A. In its forecasted expenses for employee benefits for the projected test year, the Company has included $11,700 for the supplemental retirement plan. This plan only covers certain highly-paid former executives of the Company, whose compensation exceeds limits established by the Internal Revenue Service for retirement benefits under qualified plans.

The Commission has consistently rejected recovery in rates of expenses pertaining to such supplemental retirement plans. Therefore, I recommend the Commission also reject the $11,700 proposed by the Company in this rate case.

Operating Income Adjustments

Q. PLEASE BRIEFLY DESCRIBE THE OPERATING INCOME ADJUSTMENTS THAT YOU HAVE IDENTIFIED.

A. In response to discovery, the Company has admitted that it incorrectly included $300,000 of interest expense in the calculation of the adjusted operating income included in the determination of the projected year revenue deficiency. The Company's response to the discovery request 4-Staff-UPPCO-1 admitting to this error is included in Exhibit AG-9.

Additionally, the Company has admitted to an error in the inclusion of AFUDC as a reduction of adjusted operating income instead of increasing adjusted operating income. The amount of the AFUDC is $257,800. Switching this amount from a deduction to an addition increases adjusted operating income by $515,600. Exhibit AG-9 includes the Company's response to discovery request 4-STAFF-UPPCO-1 admitting to this error.

To correct these errors, I recommend that the Commission should increase the adjusted operating income used in the determination of the Company's revenue deficiency by $815,600.

Working Capital

Q. DO YOU PROPOSE ANY ADJUSTMENTS TO THE COMPANY'S WORKING CAPITAL FORECAST OF $49.3 MILLION FOR THE PROJECTED TEST YEAR?

A. Yes. The Company projected its working capital amount for the projected test year at $49.3 million. It appears that the Company recorded a refund liability of approximately $4.7 million on its balance sheet in December 2017 to refund excess deferred taxes related to the TCJA. The Company has also proposed to refund this amount over a five year period and included $938,469 in this rate case as a reduction of federal income taxes in calculating new base rates.[7] The refund amount reduces the liability balance at the end of the projected test year to approximately $3.7 million. Therefore, the average balance of the deferred taxes liability for the projected test year is $4.2 million. This average liability amount reduces the Company's working capital for the projected test year by the same amount. Exhibit AG-10 shows the calculation of the $4.2 million average balance and the component amounts.

[7] Exhibit A-13, Schedule C8, line 10 and Exhibit AG-10.

Although the Company has included this liability in the calculation of working capital, I propose that the $4.2 million be removed from working capital and the appropriate amount be added to the deferred taxes balance that is part of the capital structure in the calculation of the overall cost of capital.

Q. PLEASE EXPLAIN WHY THE AVERAGE EXCESS DEFERRED TAX LIABILITY BALANCE FOR THE PROJECTED TEST YEAR SHOULD BE INCLUDED WITH OTHER DEFERRED TAXES IN THE CAPITAL STRUCTURE.

A. Deferred taxes are considered zero cost capital and are normally included in the capital structure as a source capital in the calculation of the overall cost of capital. Before the enactment of the TCJA, all deferred taxes at the federal tax rate of 35%, and the comparable state deferred taxes, were included in the capital structure. Subsequent to the TCJA, the Company removed the portion of deferred taxes from the capital structure due to the change in the federal tax rate from 35% to 21%. However, these amounts are still deferred taxes that have not yet been refunded and they properly belong with other deferred taxes in the capital structure at zero cost.

Therefore, the $4.2 million average excess deferred taxes liability should be removed from the calculation of working capital for projected test year and the proper amount included with deferred income taxes in the capital structure.

Q. SHOULD THE SAME AMOUNT OF $4.2 MILLION BE INCLUDED IN THE WITH DEFERRED TAXES IN THE CAPITAL STRUCTURE?

A. No. Although, ordinarily the same amount would be removed from working capital and included in the deferred taxes balance in the capital structure, in this case the Company improperly calculated the excess deferred taxes liability owed to customers. As discusses above in the section of my testimony on Excess Deferred Taxes & Refunds, the Company included the increase in deferred tax assets for tax goodwill to partially offset the total excess deferred taxes liability owned to customers. Once the goodwill-related deferred tax offset amount is removed, the excess deferred taxes liability as of December 2017 is $11.3 million instead of $4.7 million, and the average liability amount for the projected test year is $10.5 million. Exhibit AG-10 shows the calculation of the $10.5 million. This is the amount that I have added to the deferred income taxes line in the capital structure in Exhibit AG-11.

Cost of Capital

Q. **WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE OVERALL RATE OF RETURN CALCULATION?**

A. I recommend that the capital structure shown on Exhibit AG-11 be used in this case. Lines 1 and 2 show the projected long-term debt and common equity capital of the Company for the test period ending December 2019. The permanent capital balances in this exhibit reflect the numbers set forth in Company Exhibit A-14, Schedule D1, with an adjustment to reduce the Common Equity balance to $125.9 million. The result is a capital structure with 53.79% common equity and 46.21% long term debt.

Q. WHY DID YOU REDUCE THE COMMON EQUITY BALANCE FROM THE $154.4 MILLION SHOWN IN THE COMPANY'S RATE CASE FILING TO $125.9 MILLION?

The Company has proposed a permanent capital structure with a common equity component of 58.8%. This percentage is far higher than the 2017 historical test year percent of 53.2%. In the Company's last general rate case, Case No. U-17895, the Commission approved a Common Equity ratio (as a percentage of permanent capital) of 55.3%. However, during the historical test year, the Company did not take appropriate action to reach the 55.3% level, much less the 58.8% proposed in this case.

The most recent information available from the Company shows a Common Equity balance of $125.9 million at October 31, 2018 per discovery response 1-AG-UPPCO-05. This balance is slightly above the average of $125.5 million for the 12 months ended October 2018. Moreover, in part b (i) to discovery response 4-AG-UPPCO-64, the Company has stated the following

> "UPPCO is in the final stages of completing its 2019 financing plan. At present UPPCO does not anticipate or foresee the need for any additional debt or equity capital."

The statement clearly states that the Company has no current plans to inject more equity capital in the capital structure. The full responses to both discovery questions are included in Exhibit AG-19.

Q. HOW DID THE COMPANY ATTEMPT TO SUPPORT THE HIGHER COMMON EQUITY LEVEL OF 58.8% IN ITS RATE CASE TESTIMONY?

A. The Company provides no justification for the higher common equity ratio.

Q. WHAT COMMITMENTS HAVE THE COMPANY AND ITS PARENT MADE TO INJECT ADDITIONAL COMMON EQUITY CAPITAL AND REACH THE PROPOSED COMMON EQUITY RATIO OF 58.8%?

A. None. The Company received no common equity injections from its parent in 2018 and no new injections are planned in 2019. Exhibit AG-19 provides the Company's response to a discovery request confirming it.

HOW DOES YOUR RECOMMENDED 53.8% COMMON EQUITY RATIO COMPARE TO OTHER UTILITY COMPANIES?

The common equity ratio of the peer group, used to assess the cost of common equity in this case, averages 49.7%, as shown in Exhibit AG-17. It is worth noting that all the companies in the peer group are rated by S&P in the BBB category (investment grade) and these peer companies are the smaller electric utilities in the industry. Also, the lower average common equity ratio of 49.7% supports these companies' utility operations, as well as non-utility operations which tend to be somewhat more risky. The riskier non-utility operations require a higher common equity cushion to maintain similar credit ratings. Therefore, if we consider the higher equity capital required by the non-utility businesses, the equity capital for the utility portion of the peer group's capital structure would be even lower. On the other hand, UPPCO is smaller than most of the other companies in the peer group. As such, the higher common equity ratio of 53.8% is justified at this time.

Q. DID YOU CALCULATE THE DIFFERENCE IN REVENUE REQUIREMENT OF INCREASING THE COMMON EQUITY RATIO FROM 53.8% TO 58.8%?

A. Yes. If the Commission were to adopt a 58.8% common equity ratio instead of 53.8% in this case, it would unnecessarily increase the revenue requirement by approximately $1.4 million. This amount reflects the additional $28.5 million of common equity capital multiplied times the difference between the pre-tax cost of common equity (13%) and the overall pre-tax cost of capital prior to the change (7.93% pre-tax).

Q. PLEASE ADDRESS THE 2018 DOWNGRADE OF DEBT ISSUED BY THE COMPANY'S PARENT (UPPHCO) AND HOW THIS IMPACTS THE COMPANY.

A. In September 2018, Moody's Investor Service ("Moody's") lowered the Upper Peninsula Power Holding Company's (the Company's parent company) bond rating from Baa3 (investment grade) to Ba1 (non-investment grade). The Company does not have any external long-term debt. Instead, Upper Peninsula Power Holding Company ("UPPHCO") has issued all long-term debt externally and through a separate agreement with the Company, UPPHCO has funded 100% of the long term debt of the Company at the same fixed rates of interest over the term of the debt. In its report, Moody's points out UPPHCO's weak financial metrics, an elevated capital spending level at the utility, dividends paid to the parent and a high level of debt as factors they considered in arriving at the Ba1 rating.

The Moody's downgrade of UPPHCO's long-term debt to the non-investment grade level of Ba1 is likely to make financing capital expenditures at the Company more difficult and costlier in the future if appropriate "ring-fencing protections" of the utility's capital costs are not put in place by the Company.

Q. WHAT FACTORS HAVE CONTRIBUTED TO THE DOWNGRADE OF UPPHCO'S LONG TERM DEBT TO BELOW INVESTMENT GRADE?

A. There are several factors. First, the Company has increased capital spending. UPPHCO's audited financial statement show utility plant and equipment, net of depreciation, increasing from $186.6 million at December 31, 2014 to $222.9 million at December 31, 2017. This is an increase of approximately 20%. Second, instead of raising new common equity to fund capital spending, UPPHCO has initiated a return of capital to its parent (Lake AIV) for a total amount of $22.8 million during the 2014 to 2017 period. This puts pressure on the capital structure of UPPHCO which was already highly leveraged. Third, as a result of new tax legislation enacted in December 2017 (the TCJA), UPPHCO and the Company took a charge to earnings in 2017 of $8.1 million related to its non-utility power generation business. This write-off of certain deferred tax assets further reduces the common equity cushion of UPPHCO. Accordingly, the common equity of UPPHCO which was $140.7 million at December 31, 2014 has been reduced to $101.1 million at December 31, 2017, representing a decrease of 28%.

Q. PLEASE COMMENT ON THE RECENT UPPHCO DEFAULTS ON ITS LONG-TERM DEBT AGREEMENT AND HOW THIS MAY IMPACT THE COMPANY.

A. UPPHCO and its lenders amended their September 16, 2014 "Note Agreement" on November 16, 2018. The purpose of this amendment was to (a) acknowledge some number of defaults by UPPHCO; (b) seek a waiver of such defaults; and (c) to specify new conditions that UPPHCO would have to adhere to in the future. Among other things, UPPHCO admitted that it had incorrectly calculated the "Total Funded Indebtedness to Group Capitalization" ratio for the four consecutive quarters ending in September 2018, and that the correctly calculated ratios place UPPHCO in violation of the 65% maximum debt threshold permitted under the original agreement. In addition, the Company admitted that it made certain "Restricted Payments" to Lake AIV in violation of the original agreement and that a "Subsidiary Guarantee" had not yet been delivered to the lenders, as required by the original agreement. As a result, UPPHCO agreed to pay a default premium of 100 basis points on top of the interest rate originally agreed to for as long as its debt is rated non-investment grade.

It is likely that the debt downgrade of UPPHCO and its high amount of debt at 69%, including both long-term and short term debt, will have several negative repercussions on the Company if not remedied. First, UPPHCO will incur additional interest expense of approximately $2.0 million per year due to the default interest rate premium. While this is not currently an expense to be reflected on the books of the Company, a portion of future earnings of the Company will be utilized (via dividends or return of capital) to pay approximately $2.0 million of additional interest cost each year for UPPHCO's debt. Alternatively, these funds could have been used to increase the common equity component of the Company's and UPPHCO's capital structure.

Second, the potential to achieve an investment grade rating at the parent company level is made more difficult, which makes financing more difficult and expensive in the future for both the Company and its parent company.

Q. YOU MENTIONED ABOVE THAT THE UPPHCO NOTE AGREEMENT REQUIRES A GUARANTEE OF THE UPPHCO DEBT BY THE COMPANY AND THAT UPPHCO ACKNOWLEDGED THIS IN ITS SECOND AMENDMENT TO THE NOTE AGREEMENT. PLEASE COMMENT ON THIS MATTER.

A. UPPHCO has agreed to provide its lenders with a guaranty of the debt at the holding company by UPPCO.[8] For UPPCO to guarantee the debt of its parent company is very unusual among utility companies and very concerning. The long-term debt level at UPPHCO is $200 million whereas the long-term debt level at the Company is $108.2 million. The $108.2 million of long term debt was pushed down to UPPCO in 2014 based on an agreement between the Company and UPPHCO.

Since the sole business of UPPHCO is its ownership of the Company, this is a clear case of double leverage of the utility's capital structure, where the layer of equity capital at the utility is not entirely truly equity but debt capital from the parent disguised as equity. Also, with the utility now guaranteeing the debt at its parent company it becomes more apparent that the capital structure of holding company at UPPHCO should be used for setting rates in this rate case or other future rate cases.

Although, I have not taken this position in this case to give the Company and UPPHCO an opportunity to remedy the financing challenges they face. Such a position could be easily taken in the future. At this time, it is my recommendation that, minimally, (1) UPPHCO should secure additional common equity capital to rebalance the capital structure to the level established in this rate case in the capital structure of UPPCO, (2) work to regain its investment grade debt rating, and (3) renegotiate its credit agreements to remove the Subsidiary Guarantee provided by

[8] Second Amendment to the UPPHCO Note Agreement provided in response to discovery in 4-AG-UPPCO-62, part c (iv).

UPPCO and lower its interest costs. In this manner, UPPHCO should achieve additional financing flexibility and avoid any negative repercussions on the utility.

Q. DID YOU MAKE ANY ADJUSTMENTS TO OTHER ITEMS INCLUDED IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. Yes. The Company has reflected a deferred income tax balance of $12.2 million in the capital structure for the projected test year. This balance is incorrect and should be increased by $19.5 million to $31.7 million, as explained below.

Q. PLEASE EXPLAIN WHY A HIGHER LEVEL OF DEFERRED INCOME TAXES SHOULD BE INCLUDED IN THE COMPANY'S CAPITAL STRUCTURE.

A. In Exhibits A-14, Schedule D1, the Company has included a projected deferred income tax balance of $12.2 million. In discovery, the Company was asked to provide the components of this amount. In reviewing the attachment to the discovery response, it became apparent that the Company had included in the balance certain deferred tax assets pertaining to tax goodwill assets after adjusting that balance for excess deferred taxes refundable to customers as a result of the TCJA. The amount of the deferred tax assets pertaining to tax goodwill in the Company's deferred income taxes balance is approximately $9,005,000. Exhibit AG-20 includes discovery response 3-AG-UPPCO-45 showing the components of this amount.

As discussed above in the section of my testimony on Excess Deferred Taxes & Refunds, deferred tax assets relating to the tax goodwill assets should not be included in the rate making process because goodwill assets are not included in rate base and recovered in the calculation of base rates.

Additionally, and as discussed above in the Working Capital section of my testimony, the portion of excess deferred taxes that are refundable to customers needs to be included with the deferred income taxes in the capital structure. The average balance of refundable excess deferred taxes for the projected test year is $10.5 million, and the calculation is shown in Exhibit AG-10.

Therefore, the total of the adjustment items is approximately $19.5 million, which brings the total balance of deferred income taxes in the capital structure to $31.7 million as shown in Exhibit AG-11.

Q. DID YOU MAKE ANY ADJUSTMENTS TO ANY OTHER CAPITAL BALANCES IN THE COMPANY'S CAPITAL STRUCTURE?

A. Yes, I have eliminated the Capital Structure Adjustment shown on line 20 of Exhibit A-14, Schedule D1. In response to a discovery question, the Company identified three major components to the amount of $306,387 included in the capital structure. One is approximately a $43,000 balance for a self implemented rate refund. The second is an account receivable balance of $176,000 pertaining to O&M billed to ATC. The third is an $88,000 deferred tax regulatory asset of unexplained nature. Exhibit AG-21 includes the Company's discovery response identifying these items.

None of these items are a source of capital and do not belong in the capital structure for the calculation of the overall cost of capital. Perhaps, the Company should consider including these items in the calculation of working capital in the future.

Therefore, I have removed the amount of $306,387 from the projected capital structure in Exhibit AG-11 and from the calculation of the overall cost of capital.

Q. **WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL ARE YOU RECOMMENDING IN THIS CASE?**

A. I am recommending an overall return on capital of 6.37% which includes a return on common equity of 9.75%, as shown in Exhibit AG-11.

Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?

A. I have utilized the 4.46% rate determined by Company witness Kates.

Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE OTHER COMPONENTS OF THE CAPITAL STRUCTURE?

A. For Short Term Debt and Deferred Taxes, I have utilized the cost rates recommended by Company witness Kates.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-11.

A. To develop the overall cost of capital on line 11, column (f), I have first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 6.37%.

Regarding the pretax weighted cost of capital on line 11, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income taxes paid by the Company for calculation of the pretax weighted cost of 7.93% in column (h).

Q. WHAT GENERAL PRINCIPALS HAVE YOU CONSIDERED IN DETERMINING THE COST OF COMMON EQUITY FOR THE COMPANY?

A. A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court indicated that:

> *"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings*

which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties…"

The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-12.

A. Determining the cost of common equity for an enterprise or an industry group is inexact since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any one particular method. To determine the cost of common equity, I have utilized three approaches to determine this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM) and the Utility Risk Premium approach. These methodologies have previously been accepted by the Commission and have been generally accepted by regulatory commissions in other jurisdictions in the United States.

Also, I have considered the current circumstances in the Capital Markets and any potential changes in the risk profile of Upper Peninsula Power Company and the condition of the Michigan economy. Exhibit AG-12 shows a calculated cost of common equity of 8.59%. To this cost level, I have added a return premium of 0.60% to compensate the Company for its higher risk profile reflected in the higher cost of debt of UPPHCO at the lower debt rating of BB+/Ba1 compared to the peer group which is rated in the BBB category. With this adjustment, the cost of equity has increased to 9.19%, as shown on line 6 of Exhibit AG-12.

However, I have made a further adjustment and recommend an authorized rate of return on equity of 9.75% for the reasons explained later in this section of my testimony. In conjunction with the three methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER COMPANIES?

A. To develop an appropriate peer group, I chose the seven smallest companies in the electric utility industry followed by Value Line that have a bond rating from S&P in the BBB category. As an additional screening, these companies are not involved in merger and acquisition activity and have a book capitalization of $3.6 billion or less. Four of these Companies are also in the Company's peer group.

My peer group reflects the seven companies shown in Exhibit AG-13, all of which have growing earnings and dividends, and are of comparable size.

Q. HOW DOES YOUR PEER GROUP OF SEVEN COMPANIES COMPARE TO THE COMPANY'S PEER GROUP?

A. The Company's peer group is far larger at 17 companies all of which are in the BBB debt rating category. To reach this higher number of companies, the Company included far larger companies than I have selected and far larger companies than the Company itself, which has an equity book value of $124 million at December 2017.

Eight of the 17 (approximately 50%) are companies with revenues of $6.0 billion to $33 billion annually. In addition to the larger size there are other problems with the Company's inclusion of some of these companies in its peer group. First, two of the companies, Avangrid and First Energy, have had problems with paying dividends. Avangrid has no dividend history and First Energy has a frozen dividend. Two other companies, Algonquin and Emera, are Canadian companies which I discuss in the next paragraph. Sempra Energy has substantial foreign operations in Mexico, Chile and Peru. Additionally, this Company is involved in the construction of a $7 billion LNG terminal and has taken a $1.3 billion impairment loss in 2018. Also, being a California utility, Sempra has been impacted by wildfire costs and took a charge to earnings of $0.82 per share in 2017 related to non-recoverable wildfire costs. Clearly, this and the other companies are a poor fit in a peer group for setting UPPCO's cost of equity.

As mentioned above, the Company's peer group includes two Canadian companies. Emera has substantial operations in Nova Scotia, New Brunswick and the Caribbean. Moreover, Company witness McKenzie points out on page 49 of his testimony that this Company is included in the Power Generation Industry sector of Value Line's industry groupings, reflecting its significant investments and higher risks in power generation.

Foreign operations and heavy investments in power generation should disqualify it as a peer company.

Algonquin invests heavily in power generation but is also involved in acquiring a variety of smaller utility companies, primarily in the United States through its Liberty Utilities unit. The current "acquisitions" focus appears to be water and natural gas. In this regard, Liberty describes itself as "a regulated water, wastewater, natural gas, electric, and propane/air utility company". Algonquin's focus on electric generation, as well as water, and gas acquisitions makes it a poor fit as a peer company.

Q. DO YOU BELIEVE THAT THE COMPANY'S PEER GROUP IS APPROPRIATE?

A. No. The Company's peer group is focused on companies far larger than UPPCO. Additionally, some of the companies are inappropriate for inclusion in peer group due to industry focus, dividend growth questions and foreign investments.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S PEER GROUP?

A. The Commission should reject the Company's peer group for the reasons I have described.

Discounted Cash Flow (DCF) Approach

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") APPROACH.

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate, which in the case of common stocks, is the required return of equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return and this equation is:

$$R = D/P + g$$

where "R" = the Required Equity Return
"D/P" = the Dividend Yield on the Security (Dividend divided by Stock Price)
and "g" = the expected growth rate in dividends

Generally, the "D" or dividend is known and the "P" or stock price is also known as the stock trades each day. Also, recent growth in the dividend is known or estimates of growth can be determined based on earnings furnished by stock analysts, which can be relied upon with some degree of certainty. With this information, one can solve for "R" which is the required rate of return.

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-13. The stock price information in column (c) on this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days ending on December 14, 2018. The annual dividend in column (d) is the projected dividend level for 2019 as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on Value Line projections of earnings per share through the year 2021 and Yahoo Finance analysts' projected growth in earnings per share through 2019. The resulting calculation of the DCF Method indicates an average required return on common equity of 8.42% for the proxy group.

This result is lower than the Company's DCF study result which is based on seven different estimates of future earnings ranging from 9.7% to 10.3%, or approximately 10% on average. This information is shown in Exhibit A-57.

Q. **PLEASE EXPLAIN WHY WITNESS MCKENZIE'S DCF COST OF EQUITY IS MUCH HIGHER.**

A. The major difference is the inclusion of the inappropriate companies in the Company's peer group which I discussed above. The Company's DCF calculations for five of these companies, Algonquin, Emera, First Energy, Avangrid and Sempra, result in an average projected ROE of 12.64%. Had these companies been excluded from the Company peer group, the overall result would be a project cost of equity of 9.0%. The remainder of the difference reflects differences in growth rates among peer group companies in each estimate

Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. However, it also relies upon judgments of growth prospects of security analysts which may or may not be consistent with the beliefs of investors. Nevertheless, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other approaches to determining the cost of common equity.

<u>Capital Asset Pricing Model Approach</u>

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.

A. The Capital Asset Pricing Model ("CAPM") is based on the proposition that the expected return on a common equity security is a function of risk as measured by the "Beta" of that security. In equation form, CAPM is as follows:

$k_e = R_f + (B \times R_p)$ *where*

k_e = *The market cost of common equity for a specific security*

R_f = *the "risk free" rate of return*

R_p = *the overall return of the market less the risk free rate (over several years)*

B = *the systematic risk of a particular common equity security vs. the market*

Q. PLEASE EXPLAIN THE BETA OR "*B*" COMPONENT OF THE EQUATION.

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00.

Q. PLEASE EXPLAIN EXHIBIT AG-14 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-14 shows the results of the CAPM method based upon (1) a projected 4.10% risk free rate as explained below; (2) Beta information available from Value Line; and (3) Historical Market Risk Premium (R_p) information of 7.07% based on the Ibbotson Classic Yearbook through 2017.

Normally, I would use a historical risk-free rate (the current yield on 30-year treasury bonds) which as of early December 2018 is approximately 3.0%. However, sentiment in the market is fairly universal that interest rates will rise given recent and expected actions by the Federal Reserve Bank to raise interest rates as the United States economy continues to grow. I have utilized a 4.05% projected 30-year U.S. Treasury rate as the risk free rate for my CAPM analysis. This reflects the average projected rate for 2019 and 2020 as projected by IHS and made available to me in discovery response 1-AG-UPPCO-35.

As shown in Exhibit AG-14, I have added the beta adjusted peer group risk premium of 4.70% to the 4.05% risk-free rate (columns e and f) to arrive at the 8.75% ROE rate under the CAPM approach in column g. The 4.70% beta adjusted risk premium reflects the average beta for the peer group of 0.66 multiplied by the risk premium for the entire stock market ("MRP") of 7.07% described above.

Q. PLEASE COMMENT ON WITNESS MCKENZIE'S CALCULATION OF THE AVERAGE CAPM ROE AT 11.0% TO 11.2%, WHICH IS APPROXIMATELY 245 BASIS POINTS HIGHER THAN YOUR ESTIMATE.

A. In Exhibit A-57, witness McKenzie calculates his 12.2% CAPM based on a projected 30-year Treasury bond yield for the 2019-2023 period. His 11.2% CAPM rate is based on the current 30-year Treasury bond yield of 3.0%. As noted above, I use a 7.07% MRP in my analysis. In contrast, Mr. McKenzie uses a 9.5% MRP as shown on page 2 of Exhibit A-63. The difference in the risk premium is the biggest factor contributing to the difference between my estimate and his estimate. I will discuss the flaws in Mr. McKenzie's calculation of the 9.5% risk premium below. The other major differences between Mr. McKenzie's estimate and my estimate are shown in the following comparison.

	UPPCO Estimate	AG Estimate
Market Risk Premium (MRP)	9.50%	7.07%
Average Beta	0.69	0.66
MRP x Avg. Beta	6.56%	4.70%
Risk Free Rate	4.00	4.05
Size Adjustment	0.70	0.00
Other	(0.04)	0.00
Total CAPM Estimate	**11.20%**	**8.75%**

Regarding the MRP, I have developed my MRP from stock market returns over the 1926 to 2017 period as compiled by Ibbotson Associates. The stock market returns over the 1926-2017 period average to 12.06%. This long-term average stock market return less the yield on long term government bonds of 4.99% results in a difference in the MRP of 7.07%. This is the traditional and widely accepted approach to determine the MRP for cost of equity under the CAPM methodology.

In contrast, in the development of his MRP, Mr. McKenzie first develops a projection of earnings growth of 11.1% from the S&P 500 dividend paying stocks, calculated over five years, based on data from Zacks, IBES and Value Line. To this earnings growth rate, he adds the dividend yield of the S&P 500 of 2.4% to arrive at a projected return for the market of 13.5%. From this rate, he subtracts a 4.00% risk-free rate to arrive at his 9.5% MRP. All these calculations may seem to make sense on the surface. However, the methodology and result are seriously flawed.

First, earnings growth rates estimated by securities analysts over the coming years are not necessarily indicative of long-term stock market returns. These short-term earnings estimates typically reflect the near-term prospects based on an extension of the current business cycle and do not take into consideration the inevitable downturns and economic expansions over multiple decades. The necessity for calculating the MRP over a long time period is supported by academic research which I discuss further below.

Second, the long-term yield on bonds to determine the difference, or MRP, between the stock market return and the cost of government bonds, must also be calculated over a long time period. Mr. McKenzie's calculations do not meet this requirement. His 4% bond yield reflects near term expectations over a five-year period, and therefore is inconsistent with the calculation of a market premium of the long-term.

Q. IS THERE ANY ACADEMIC SUPPORT FOR THE USE OF LONGER PERIODS FOR THE DEVELOPMENT OF MRP RATES?

A. Yes. Dr. Roger Morin, who is quoted by witness McKenzie in other sections of his testimony, favors the use of the longest possible period for calculating a risk premium. On page 114 of his book "New Regulatory Finance", Dr. Morin makes the following point.

> *"Therefore, an historical risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect. Only over long time periods will investor return expectations and realizations converge. Clearly, the*

accuracy of the realized risk premium as an estimator of the prospective risk premium is enhanced by increasing the number of years used to estimate it…."

Accordingly, the use of data over a short time period, be they historical or projected, are to be avoided in the development of a risk premium estimates or MRP.

In conclusion, Mr. McKenzie's MRP calculation is unorthodox, not appropriate, and not realistic. The Commission should disregard it.

Q. PLEASE DISCUSS MR. MCKENZIE'S ADDITION OF A COMPANY-SIZE PREMIUM?

A. In his calculation of the CAPM cost of equity, Mr. McKenzie has also included a company-size premium of 0.70%. Mr. McKenzie sourced this premium from Morningstar, an investment research firm. However, the small-size risk premium of 0.70% pertains to all segments of the securities market, including upstart technology companies and other small companies in non-regulated industries.

While I believe that small companies have a higher cost of equity than larger companies, there are significant differences in regulated versus high-risk upstart companies and other non-regulated companies that compete for market share, prices and have significant earnings volatility. UPPCO is operating "under the blanket of regulatory protection" and, as such, its size risk is greatly reduced relative to companies in other industries. Therefore, the Morningstar small company's return premium is not applicable with regard to UPPCO in determining the CAPM cost of equity capital. As shown in Exhibit

AG-12, I have allowed for UPPCO's higher risk profile in a different manner by adding 60 basis points to the overall calculation of the cost of equity, plus I have increased the recommended ROE from 9.19% to 9.75% to take the Company's size and other items into consideration.

Q. **PLEASE COMMENT ON MR. MCKENZIE'S ECAPM ESTIMATES?**

Mr. McKenzie's ECAPM estimates build off of his CAPM estimates. Therefore, his results are corrupted by the same MRP development problem outlined above. The basic justification for the ECAPM is the theory that Value Line betas tend to under-predict stock market returns for lower beta stocks (see McKenzie testimony beginning on page 69). While the initial studies supporting ECAPM were conducted several years ago, the Company offers no testimony to substantiate its position that Value Line has not reacted to correct its betas for the purported under-estimation problem.

Moreover, the ECAPM approach to estimating ROE is not widely used in the utility industry. Mr. McKenzie alluded to its support by the Alaska Commission on page 72 of his testimony. Also on page 72, he noted its use in Wyoming and Arkansas. Through discovery, I asked him to provide any rate orders where the Commissions in these states endorsed or supported ECAPM. In his response to discovery request 1-AG-UPPCO-36, he confirmed that the cases he identified in testimony were "…resolved through settlements and neither the Wyoming PSC…nor the Arkansas PSC…" addressed the merits of the specific evidence presented by ROE witnesses who proposed the use of ECAPM.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S CAPM AND ECAPM ROE ESTIMATES?

A. The Commission should give no weight to the Company's CAPM and ECAPM estimates. First, they are both dependent upon a flawed projected MRP estimate of 9.5% determined over a short time period. Second, the Company's size return premium adjustment is faulty as previously discussed. Third, the Company's ECAPM approach is dependent upon the first two factors noted in this paragraph. Furthermore, the Company did not provide sufficient compelling evidence to justify use of the ECAPM.

Q. PLEASE ASSESS THE CAPM APPROACH.

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that is assumes that the entire risk of a stock can be measured by the "Beta" component, and as such the only risk an investor faces is created by fluctuations in the overall market. In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security. As such, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

Utility Risk Premium Approach

Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM APPROACH OF ESTIMATING THE COST OF COMMON EQUITY.

A. In general, one can estimate the cost of common equity by estimating three components and adding them together. The three components are (1) the risk-free rate of return on 30-year U. S. Treasury Bonds; (2) the historical differential between yields of the rated utility bonds of the Company and the 30-year U.S. Treasury Bonds (risk-free rate); and (3) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-15 shows the three components required to estimate the cost of common equity under this approach. The results for this approach reflect a return on common equity of 8.75%. To arrive at this result, I have used the 4.30% historical spread of electric utility common stock returns relative to A rated utility bonds. Also, I have used a 0.40% adjustment factor to reflect BBB bonds (i.e. the spread of BBB vs. A rated bonds). These two components are added to the risk-free rate from my CAPM analysis which is 4.05%. Also, in the calculation of the overall cost of equity capital, I have taken into consideration a higher risk premium for the fact that the Company's parent company has a below investment grade debt rating of Ba1.

Q. ON PAGES 73 TO 77 OF HIS DIRECT TESTIMONY, MR. MCKENZIE DISCUSSES HIS UTILITY RISK PREMIUM APPROACH WHICH SEEKS TO SUPPORT AN ROE IN THE RANGE OF 9.9% TO 11.0%. PLEASE DISCUSS HIS ANALYSIS AND CONCLUSIONS.

A. In his analysis, Mr. McKenzie attempts to establish a correlation between bond interest rates and authorized ROEs over the period 1974 to 2017. His conclusion is that authorized ROEs have not changed in lock step with utility bond interest rates over this time period. Instead, authorized ROEs have declined far less than utility bond rates. For example, as shown on page 3 of Exhibit A-64, the differential between utility bond rates and average authorized ROEs was 1.08% in 1980 (ROE of 14.23% versus Bond Rate of 13.15%). However, according to Mr. McKenzie's analysis, this differential increased to 5.67% in 2017 (Average ROE of 9.75% versus 4.07% bond rate).

Using a statistical model, Mr. McKenzie has calculated the correlation between these two variables over the 1974 to 2017 time period to be approximately 43.18%. On pages 1 and 2 of Exhibit A-64, he then calculates an ROE of 9.94% based on current interest rates and an ROE of 11.0% based on projected interest rates during 2019 to 2023.

Q. WHAT IS YOUR ASSESSMENT OF MR. MCKENZIE'S CALCULATIONS OF PROJECTED ROE RATES USING HIS UTILITY RISK PREMIUM APPROACH?

A. Mr. McKenzie's approach is not a sound or valid approach to calculating an appropriate cost of equity capital. It has no academically sound basis. This approach is an unproven theory, not a new risk premium model. His thesis is that the cost of equity capital can be determined using the historical difference between the average ROE rates granted to utilities and the utility bond interest rates effective in the market at or near the time the ROE rates were granted. He then takes this difference, or what Mr. McKenzie assumes to be a risk premium, and adds it to current and forecasted bond interest rates to supposedly arrive at the current cost of capital.

There are several flaws with this approach to determine a risk premium and a proposed cost of equity. First, the ROE rates granted by regulatory commissions do not always reflect the cost of equity calculated through proven conventional methods. Commissions use very subjective factors to subtract or add to the cost of equity rates proposed by cost of equity experts, usually adding an additional percentage cushion instead of subtracting from the recommended rates. This alone adds an upward bias to the risk premium calculated by Mr. McKenzie, particularly during the steep decline in interest rates in the past 10 years.

Second, there is a significant time lag between the decline in interest rates and the downward or upward adjustment to the ROE rate granted by regulatory commissions. This lack of synchronization makes any comparison between the two rates and calculation of a difference or risk premium totally unreliable. Third, no academic studies have been performed to provide any credence to such a method to calculate a risk premium. This is simply a creation of Mr. McKenzie because it fits his desired outcome of a higher ROE above 10%.

In summary, the Commission should disregard this latest attempt to influence the serious process of establishing a fair and industry comparable ROE rate through gimmicky and unproven methods.

Q. PLEASE COMMENT ON MR. MCKENZIE'S EXPECTED EARNINGS ANALYSIS WHICH HE DISCUSSES ON PAGES 77 THROUGH 80 OF HIS TESTIMONY.

A. As shown in Exhibit A-65, Mr. McKenzie derives a 10.9% projected average return rate on the book value of common equity for his peer group. He uses this estimated return rate as a determinant of his recommended ROE of 10.50%.

Unfortunately, this is not an academically sound approach to determining the cost of common equity for a company. Mr. McKenzie is simply dividing (1) the projected earnings per share ("EPS") approximately four years from now for each peer group company (as estimated by Value Line) by (2) the projected Book Value for each such peer group company. This exercise perhaps has some use in evaluating how well each peer group company employs capital over longer periods of time but is useless as a tool to set the authorized ROE of a utility company. This method does not take into account investors' expectations or stock market parameters.

The Commission should also recognize the inherent circularity in relying upon this method advocated by the Company. If utility commissions were to rely upon this methodology, utilities in effect would indirectly be setting their own allowed ROE or highly influencing those ROEs by estimating ever increasing EPS.

This approach appears to be nothing more than an attempt to find a cost of capital calculation method to fit a desired level of return on equity. My recommendation is that the Commission should give no weight or reliance to this alternative method.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN 2017 AND 2018.

A. Since 1990, return on equity rates, granted by regulatory commissions in the U. S., have been in a steady decline from over 12.7% in 1990 to approximately 9.5% in 2017 and 2018.

Pages 2, 3 and 4 of Exhibit AG-18 show the more recent ROE rates granted by state regulatory commissions for electric utilities during 2017 and the first six months of 2018 as published by Regulatory Research Associates, a respected and independent regulatory research firm. Nearly 80% of the electric decisions rendered (excluding limited issue riders) involved ROE rates averaging approximately 9.6% during the eighteen-month period ending June 2018.

Page 2 of Exhibit AG-18 shows that there were only thirteen ROE decisions with ROE rates at 10% or higher for electric companies during the 18 months ended June 2018 with four of these decisions handed down by the Michigan Public Service Commission. In contrast, there were 49 electric ROE decisions with authorized rates below the 10% level. These 49 decisions are summarized on pages 3 and 4 of this exhibit and include information regarding debt financing subsequent to the rate orders. It is clear from this information that the debt capital markets have continued to be receptive to financing raised from the utilities with authorized ROEs below 10%. In fact, the capital markets continue to provide debt capital at competitive interest rates to these utilities even with ROEs of 9.5% or lower.

It is also noteworthy to point out that the average ROE granted to the Company's peer group during the 18 months ended June 2018 was 9.48%.

Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THE COMMISSION SHOULD USE IN THIS CASE.

A. In Exhibit AG-12, I have summarized the cost of equity rates from the three methods I used. The range of returns for the industry peer group is from 8.42% at the low end using the DCF approach and 8.75% at the high end using the CAPM and Utility Risk Premium approaches.

As explained earlier in my testimony, I give more weight to the DCF method as a more reliable approach to estimating the cost of equity, which in my analysis is 8.42%. In this regard, on line 4 of Exhibit AG-12, I have calculated a weighted return on equity of the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted return on equity of 8.59% for the average of the industry peer group. To this result, I have added a risk premium of 0.60% to recognize that the peer group is rated BBB but that UPPCO is rated at Ba1. This results in a calculated ROE of 9.19%. However, I am recommending a higher ROE rate of 9.75% for UPPCO for the reasons explained below.

First, while the peer group I selected consists of smaller companies within the electric utility industry, UPPCO is somewhat smaller than the peer group. Therefore, a slightly higher ROE may be warranted. Second, the extent to which investors anticipate higher interest rates is uncertain. As such, while the cost of common equity under the DCF approach is an accurate assessment of expectations for the forecasted test year at this time, the higher interest rates assumed in this case may very well produce a different result should such higher interest rates become a reality. In this regard, a potential 10% correction in utility stock prices due to higher interest rates would produce a 0.40% increase in the cost of capital under the DCF approach. Third, the Company's risk related to industrial customers is somewhat higher than companies in my peer group. Sooner or later the current business cycle will end and UPPCO may face the prospect of reduced demand from industrial customers and potentially some higher uncollectible costs.

Finally, I understand that the Commission may be reluctant to set an ROE for the Company at the true cost of equity of approximately 9.2%. As shown in Exhibit AG-18, regulatory commissions around the country have granted an average ROE of 9.50% to electric utilities during 2017 and slightly above this number during the first six months of 2018. In fact, approximately 80% of the reported ROE decisions in electric utility rate cases reported by "Regulatory Focus" during this timeframe are well below 10%. Therefore, my recommended ROE rate of 9.75% in this case is reasonable and fair, if not generous, as a gradual transition to the true cost of equity.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.75% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. In recent general rate case proceedings, the Commission seems to have been persuaded by the applicants' arguments that they should receive an ROE of 10% or higher to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. Exhibit AG-18 shows several utilities that have accessed the capital markets at competitive interest rates since receiving an ROE substantially below 10%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-16 shows the market to book ratios for each of the peer group companies. The average ratio of nearly 2x market to book value indicates that investors are attracted to utility stocks because they provide returns well above the cost of equity capital. This phenomenon is the result of utility companies receiving ROEs ranging between 9.4% and 9.6%, as shown in Exhibit AG-18.

This information should dispel the myth that the Company must receive an ROE at or above 10%, or it will face dire consequences in the financial markets.

Q. IF THE COMMISSION APPROVES A 10.0% COST OF COMMON EQUITY IN THIS CASE (AS IT DID IN THE COMPANY'S PRIOR CASE), WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.75%.

A. Assuming the Commission grants a 10.00% ROE in this case versus a 9.75% ROE, the additional cost to customers is approximately $430,000 annually, which would represent nearly 5% of the requested rate increase in this rate case. There is absolutely no need to burden customers with this additional cost.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company an ROE of no more than 9.75%.

Rate Design

Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR RESIDENTIAL CUSTOMERS HAS THE COMPANY PROPOSED?

A. In his direct testimony, Company witness Eric Stocking proposes to increase the monthly service charge for residential customers from $15 to $25 per month. In his testimony, he states that the justification for the increase in the monthly service charge for residential and other customer groups is the result of electric utilities having high fixed costs for delivering basic services and is supported by the cost of service study.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The proposed increase from $15 to $25 per month represents an increase of 67%. This very large increase would create rate shock particularly for customers living in smaller homes using less electricity than the average customer and violates the objective of rate gradualism.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject the proposed increase in the residential customer monthly charge in this case. The current customer monthly charge of $15 is one of the highest among the electric utilities regulated by the Commission. Although the cost of service study includes assumptions as to how certain fixed costs should be allocated, not all fixed costs should necessarily be recovered through the monthly service charge.

When rates need to be increased it is advisable to increase the volumetric rate by a larger proportion than the fixed monthly charge. Customers cannot change the monthly charge they are billed, but they can change the amount of power they consume by added conservation. Therefore, if the volumetric rate increases and the electric bill goes up, the customer can reduce consumption and thus control the size of its electric bill. Higher volumetric rates in effect spur conservation which fixed monthly charges cannot do.

Therefore my recommendation is that the monthly Service Charge for Residential customers should stay unchanged.

Q. HAS THE COMPANY ALSO PROPOSED AN INCREASE IN THE MONTHLY SERVICE CHARGE FOR SMALL AND MEDIUM COMMERCIAL CUSTOMER?

A. Yes. The Company has proposed to increase the monthly service charge for small commercial from $17 to $50. This represents an increase of 194%. The Company also has proposed to increase the monthly service charge for medium-size commercial customers from $35 to $60. This represents an increase of 71%. Both increases are significantly large and would likely cause negative customer reaction. In addition, the same issues with energy conservation and controlling customer bills exist with commercial customers as discussed above for residential customers. and defeats the objective of rate gradualism.

Q. WHAT DO YOU RECOMMEND?

A. Applying the concept of gradualism, I recommend that the Commission should increase the monthly service charge for small commercial customers to $20, which is an 18% increase over the current service charge. I also recommend that the Commission should increase the service charge for medium-size commercial customers to $40 from $35 for an increase of 14%.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony to incorporate new information that may become available.

Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for more than 15 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

During his 24-year career at MCN and MichCon, he held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

ENERGY INDUSTRY EXPERIENCE

Mr. Coppola has been an independent consultant for more than 15 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated gas utility operations and non-regulated businesses. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company.

During his 24-year career at MCN and MichCon, he held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he has directed the issuance of more than $2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He has established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders and other regulatory proceedings. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, he has been intricately involved in operating and construction programs, gas cost recovery and reconciliation cases, gas purchase strategies and rate case filings.

Experience and Qualifications of Sebastian Coppola

Mr. Coppola has extensive experience with gas utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, Detroit Edison, MichCon (DTE Gas), Michigan Gas Utilities Corp, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company and Wisconsin Public Service Company.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

As manager of customer billing, Mr. Coppola developed intricate knowledge of customer billing and meter reading operations. As manager of

Experience and Qualifications
of Sebastian Coppola

materials inventory and warehousing accounting, he also developed intricate knowledge of pipeline and materials procurement, warehousing and construction operations including safety compliance issues. Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

- **Specific Regulatory Proceedings And Related Experience:**
  - Filed testimony on behalf of the Michigan Attorney General in DTE Electric (DTEE) 2018 rate Case U-20162 on several issues, including operations and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
  - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2018 Tax Credit B refund for the Electric Division in case U-20286.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the

Experience and Qualifications
of Sebastian Coppola

Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.

- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.

Experience and Qualifications of Sebastian Coppola

- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.

Experience and Qualifications of Sebastian Coppola

- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including

sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.

- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales

Experience and Qualifications of Sebastian Coppola

volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.

- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.

Experience and Qualifications
of Sebastian Coppola

- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the "Massachusetts Formula" at MichCon and at SEMCO in 1975 and 2000.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
Michigan Attorney General's Third Discovery Request

03-AG-UPPCO-57

Refer to page 10, lines 1-12, of Mr. Haenel's direct testimony. Please:

a. Confirm that Case No. U-17895 and in prior years, the costs and revenues related to the Escanaba Hydro facilities were not included in setting rates for UPPCO's retail customers. If not confirming, please explain.

b. Confirm that the Escanaba Hydro facilities serve only one customer and the facilities are not interconnected with the Company's electric distribution system. If not confirming, please explain.

c. Provide the name of the customer that uses the generation of the Escanaba Hydro facilities and the date when the relationship began.

d. Explain how the Escanaba Hydro facilities came to be and why they only serve this customer.

e. Provide the amount of generation in MWh sold to the customer in each year 2012 to 2018, and the percent of the available capacity that sales volumes represent for each year.

f. Confirm that by the statement "In addition, these have always been regulated facilities…" the Company is solely referring to the Commission approval of the special customer contracts. If not confirming, explain what other regulation has occurred.

UPPCO Response

a. Yes, they were not included.

b. Yes, they serve one customer.

c. Verso, today's customer, purchased the mill from Escanaba Paper Company in 2015.

d. UPPCO does not know the complete history of the Escanaba Hydro facilities; however, the current MPSC-approved PPA is consistent with the current electrical configuration serving this one customer.

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
Michigan Attorney General's Third Discovery Request

e. Please see 3-AG-UPPCO-40e Attachment.xls

f. No, the statement is primarily referring to the fact that these units are regulated by FERC regarding its licensing to generate power.

Response by: Gradon R. Haehnel, Director of Regulatory Affairs
Dated: 1/29/2019

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
Michigan Attorney General's Third Discovery Request

03-AG-UPPCO-60

Refer to discovery response 14-Staff-UPPCO-6. Please:

a. Explain why the amounts were revised from the initial proposal.
b. Provide the annual Escanaba Hydro expenses that were used to calculate the forecasted expense of $1,024,952.
c. Provide the calculation of the $30,113 in depreciation expense and property taxes of $30,000.
d. Does the Company have a written commitment from the customers using the Escanaba Hydro generation that it will pay the incremental revenue requirement of $262,921?
e. The $262,921 incremental revenue requirement appears excessive when considering the existing forecasted revenue of $1,114,883 less operating expenses of $1,024,952, depreciation expense of $30,113 and property taxes of $30,000. These amounts net to a gross profit of
f. $29,818. The net rate base addition of approximately $1.5 million multiplied by the proposed pre-tax overall cost of capital of approximately 9.56% results in a return on capital of $143,400. This amount less the $29,818 should net out to an incremental revenue requirement of approximately $113,000. Please explain and support the $262,921 with appropriate calculations in Excel with formulas intact.

UPPCO Response

a. Please see response to 6-STAFF-UPPCO-5.
b. UPPCO used a simple 5-year average, as demonstrated in "Copy of GLN5250M IS for STAFF.xls", filed as part of the pre-filing requirements. Reference cells S269 in worksheet and subtract the depreciation expense projected in cell P266.
c. Property taxes are simply an assumed input value of $30,000. Depreciation assumed an approximate 2% depreciation rate.
d. No. The incremental revenue requirement is assumed to be paid for by the counterparty of the PPA. The Company is currently having a dialogue with the counterparty regarding the status of the current PPA as it relates to this case.
e. Please see UPPCO's revised response to 5-STAFF-UPPCO-2 which supports the appropriate calculations.

Response by: Gradon R. Haehnel, Director of Regulatory Affairs
Dated: 1/29/2019

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
VERSO's
Second Discovery Request

2-VERSO-UPPCO-6

What cost will be incurred by the rate payers to correct the "safety-related issues" or "FERC-mandated Project alterations repairs or improvements" if the Commission grants UPPCO's request to move the Escanaba Hydro Facilities into the rate base and Verso does not agree to amend the special contract?

UPPCO Response

Cost estimates that rate payers may incur due to FERC-mandated Projects are as follows:

Boney Falls – Gated Spillway Resurfacing; Current budgetary estimate is $1.0 - $1.3M
Boney Falls – Overflow Spillway Resurfacing; Current budgetary estimate is $0.7 - $1.0M
Boney Falls – Tainter Gate Refurbishment; Current budgetary estimate is $0.4 - $0.6M

The Safety-related Projects are as follows:

Boney Falls – Transformer Replacement; Current budgetary estimate is $0.2 - $0.4M
Dam 1 – Arc Flash /Controls Upgrade; Current budgetary estimate is $0.6 - $0.8M

Total current budgetary estimate for FERC-mandated Projects is; $2.9M – $4.1M

Response by: Virgil E. Schlorke, Director of Generation and Environmental Services
Dated: 2/1/2019

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
MPSC Staff's
Thirtieth Discovery Request

30-STAFF-UPPCO-4

If the Escanaba Hydro facilities were to be retired in the next year, please identify what the cost of decommissioning would be.

a. Please Confirm that the decommissioning costs would indeed be between $30,874,526.89 and $64,124,017.39 as shown in cells I111 and F111 in the Excel workbook labeled Escanaba Removal Estimate attached to discovery response 14-STAFF-UPPCO-5

b. Please explain why in the same workbook cell I2 labeled "Total FERC & Other Agency Associated Costs (including river Channel Restoration)" is a sum of cells I3 through I102 when, Cells I22,I25,I54 and I78 are subtotals for Line removal, decommissioning of Boney Falls, decommissioning of Dam #3 and decommissioning of Dam #1 respectively.

UPPCO Response:

a. The range of decommissioning costs provided in response to 14-STAFF-5 are estimates. UPPCO cannot confirm that these "would indeed be" the cost range.

b. This is an error. Please see revised attachment to 14-STAFF-UPPCO-5.

Response by: Gradon R. Haehnel, Director of Regulatory Affairs
Dated: 01/24/2019

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Calculation of Excess Deferred Taxes from reduction in Federal Tax Rate from 35% to 21% [1]

		Schedule M Items @ 12/31/2017			Deferred Taxes @12/31/2017			
		Beginning Balance	Activity	Ending Balance	Beginning Balance	Activity I/S Related	Excess Deferred Taxes Pre-Grossup	Activity- Regulatory Grossup
Bad Debts		$1,000,000	$730,000	$1,730,000	$389,000	$283,970	($227,668)	($78,914)
CIAC (P-I-S) Fed	Protected	$1,324,605	$55,923	$1,380,528	$463,612	$19,573	($193,274)	($66,993)
CIAC (P-I-S) MI	Protected	$1,324,605	$55,923	$1,380,528	$51,660	$2,181	$11,596	$4,020
Customer Advances		$1,972,579	($55,997)	$1,916,582	$767,333	($21,783)	($252,222)	($87,425)
Def Compensation		$73,964	$121,192	$195,156	$28,772	$47,144	($25,683)	($8,902)
Def Inc & Deduct Cur		($7,304,931)	$44,243	($7,260,689)	($2,841,618)	$17,210	$955,507	$331,198
Depreciation (Plant)	Protected	($26,953,068)	($25,736,050)	($52,689,118)	($9,433,574)	($9,007,618)	$7,376,477	$2,556,834
Depreciation (Plant) (MI)	Protected	($19,869,515)	($20,342,560)	($40,212,075)	($774,911)	($793,360)	($337,781)	($117,082)
Environmental Cleanup		($838,921)	$74,192	($764,728)	($326,340)	$28,861	$100,638	$34,883
Future Proposed Adjustments (Fed)		($512,662)	$1,361,657	$848,995	($179,432)	$476,580	($118,859)	($41,199)
Future Proposed Adjustments (MI)		($512,662)	$1,361,657	$848,995	($19,994)	$53,105	$7,132	$2,472
Goodwill		$54,816,685	($4,356,249)	$50,460,436	$19,185,840	($1,524,687)	($7,064,461)	($2,448,683)
Goodwill (MI)		$54,816,685	($4,356,248)	$50,460,437	$2,137,851	($169,894)	$423,868	$146,921
Interest		($878,474)	$479,289	($399,185)	($341,726)	$186,443	$52,533	$18,209
Net Operating Loss - Fed		$9,049,067	$9,788,437	$18,837,504	$3,167,173	$3,425,953	($2,637,251)	($914,124)
Net Operating Loss - MI		$1,965,515	$4,394,946	$6,360,461	$76,655	$171,403	$53,428	$18,519
Pension		($58,667,770)	$1,241,366	($57,426,404)	($22,821,763)	$482,891	$7,557,315	$2,619,516
Pension Restoration		$156,027	$19,537	$175,564	$60,695	$7,600	($23,104)	($8,008)
Pension Restoration - Current		$28,849	($20)	$28,829	$11,222	($8)	($3,794)	($1,315)
Post Retirement - Med/Dental		$1,387,424	($99,851)	$1,287,573	$539,708	($38,842)	($169,445)	($58,733)
Post Retirement - Med/Dental - Current		$24,093	$0	$24,093	$9,372	$0	($3,171)	($1,099)
Post Retirement Life		$485,608	$106,502	$592,110	$188,901	$41,429	($77,922)	($27,009)
Price Risk Hedging (NonCur-Asset)		$187,802	($170,280)	$17,522	$73,055	($66,239)	($2,306)	($799)
Reg Asset ST		($55,000)	$0	($55,000)	($21,395)	$0	$7,238	$2,509
Reg Asset ST Offset		$55,000	$0	$55,000	$21,395	$0	($7,238)	($2,509)
Reg Assets (Current)		($407,030)	$4,882,837	$4,475,806	($158,335)	$1,899,423	($589,016)	($204,165)
Reg Assets (Non-Current)		($28,975)	$0	($28,975)	($11,271)	$0	$3,813	$1,322
Reg Liab ST		$187,802	($170,280)	$17,522	$73,055	($66,239)	($2,306)	($799)
Reg Liab ST Offset		($187,802)	$170,280	($17,522)	($73,055)	$66,239	$2,306	$799
Reg Liabilities-Non-Cur		$877,106	($110,908)	$766,198	$341,194	($43,143)	($100,832)	($34,950)
Regulatory Asset-Auto Current-DNU		$0	$0	$0	$0	$0	$0	$0
Restricted Stock		$119,204	($24,865)	$94,339	$46,370	($9,673)	($12,415)	($4,303)
SERP		$19,759	($751)	$19,008	$7,686	($292)	($2,501)	($867)
SERP - Current		$27,004	($4,780)	$22,224	$10,505	($1,859)	($2,925)	($1,014)
Sick Leave - Current		$41,370	($859)	$40,511	$16,093	($334)	($5,331)	($1,848)
Total For UPPCo:		$13,723,942	($30,541,716)	($16,817,774)	($9,336,266)	($4,533,965)	$4,692,346	$1,626,461
		$13,723,943	($30,541,717)	($16,817,775)	($9,336,267)	($4,533,966)	$4,692,346	$6,318,807
								Gross-up @ 1.3466

Source: (1) UPPCO response to Staff Data Request BAW 2-1.

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Calculation of Excess Deferred Taxes from reduction in Fe

		Plant Related (Dep and CIAC)			Tax Goodwill			Other Items		
		PLANT-PROTECTED			GOODWILL-NOT PROTECTED			NOT PROTECTED		
		Deferred Taxes w/o Tax Rate Change		Deferred Taxes with Tax Rate Change	Deferred Taxes w/o Tax Rate Change		Deferred Taxes with Tax Rate Change	Deferred Taxes w/o Tax Rate Change		Deferred Taxes with Tax Rate Change
Bad Debts								$672,970	38.90%	$445,302
CIAC (P-I-S) Fed	Protected	$483,185	35.00%	$289,911						
CIAC (P-I-S) MI	Protected	$53,841	3.90%	$65,437						
Customer Advances								$745,550	38.90%	$493,328
Def Compensation								$75,916	38.90%	$50,233
Def Inc & Deduct Cur								($2,824,408)	38.90%	($1,868,902)
Depreciation (Plant)	Protected	($18,441,192)	35.00%	($11,064,715)						
Depreciation (Plant) (MI)	Protected	($1,568,271)	3.90%	($1,906,052)						
Environmental Cleanup								($297,479)	38.90%	($196,841)
Future Proposed Adjustments (Fed)								$297,148	35.00%	$178,289
Future Proposed Adjustments (MI)								$33,111	3.90%	$40,242
Goodwill					$17,661,153	35.00%	$10,596,691			
Goodwill (MI)					$1,967,957	3.90%	$2,391,825			
Interest								($155,283)	38.90%	($102,750)
Net Operating Loss - Fed		($19,472,437)		($12,615,419)	$19,629,110		$12,988,516	$6,593,126	35.00%	$3,955,876
Net Operating Loss - MI			Excess	$6,857,018		Excess	($6,640,594)	$248,058	3.90%	$301,486
Pension								($22,338,872)	38.90%	($14,781,556)
Pension Restoration				1.3466			1.3466	$68,295	38.90%	$45,190
Pension Restoration - Current		Gross up - Protected		$ 9,233,660			$ (8,942,224)	$11,214	38.90%	$7,421
Post Retirement - Med/Dental								$500,866	38.90%	$331,421
Post Retirement - Med/Dental - Current								$9,372	38.90%	$6,202
Post Retirement Life								$230,330	38.90%	$152,409
Price Risk Hedging (NonCur-Asset)								$6,816	38.90%	$4,510
Reg Asset ST								($21,395)	38.90%	($14,157)
Reg Asset ST Offset								$21,395	38.90%	$14,157
Reg Assets (Current)								$1,741,088	38.90%	$1,152,073
Reg Assets (Non-Current)								($11,271)	38.90%	($7,458)
Reg Liab ST								$6,816	38.90%	$4,510
Reg Liab ST Offset								($6,816)	38.90%	($4,510)
Reg Liabilities-Non-Cur								$298,051	38.90%	$197,219
Regulatory Asset-Auto Current-DNU										
Restricted Stock								$36,697	38.90%	$24,283
SERP								$7,394	38.90%	$4,893
SERP - Current								$8,646	38.90%	$5,721
Sick Leave - Current								$15,759	38.90%	$10,428
Total For UPPCo:								($14,026,906)		($9,550,981)
									Excess	$4,475,925
										1.3466
								Gross up		$6,027,281

UPPCO Sum of three items:		
Excess Tax Liability-pre-gross up		**$4,692,346**
Gross up Factor		1.3466
Gross Amount Refundable to customers	$	6,318,713

AG Sum of two items, excluding Goodwill:		
Excess Tax Liability-pre-gross up		**$11,332,943**
Gross up Factor		1.3466
Gross Amount Refundable to customers	$	15,260,941

Source: (1) UPPCO response to Staff Data Request BAW 2-

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
Michigan Attorney General's Third Discovery Request

03-AG-UPPCO-54

Refer to page 36, lines 1-16, of Mr. Kates' direct testimony and the Excel worksheet to Staff

Audit Response BAW 2-1. Please:

a. Provide the amortization period and amount of the "Protected" items identified in the BAW 2-1 worksheet for each year of the amortization period with the underlying calculations in Excel and formulas intact.

b. Explain why the excess deferred tax assets related to the Goodwill amount of $54.8 million are being used to offset the excess deferred liabilities and refund amount for other non-protected items when the Goodwill amount is not being recovered in base rates.

c. Provide the remaining amortization period for Goodwill as of 12/31/2017.

d. Provide the remaining amortization period for each of the Schedule M items in worksheet BAW 2-1 as of 12/31/2017 in Excel.

e. Explain what the amounts in worksheet BAW 2-1 column H "Activity- Regulatory Pre-Grossup represent and how they were determined.

f. Explain how the Ending Balances in column K of the worksheet BAW 2-1 were determined.

g. Refers the worksheet BAW 2-1 and confirm that the gross up of the refundable protected excess ADIT is $9,233,660, the gross up of the Goodwill excess ADIT recoverable receivable amount is $8,942,224, and the gross up of the remaining refundable unprotected excess ADIT is $6,027,281, if separately calculated. If not confirming, please provide the correct amounts and the underlying calculations in Excel with formulas intact.

h. Explain specifically what the statement "UPPCO proposes treating this group in aggregate and establishing a single amortization period to reverse as part of its next rate case" on lines 12-13. What is being reversed and why in the next rate case?

i. Explain the statement on lines 14-16. What material pre-existing regulatory assets and liabilities do not need to be re-measured? Didn't the Company perform this re-measurement in worksheet BAW 2-1?

UPPCO Response

a. The company has not prepared this analysis based on its proposed approach for handling excess deferred taxes within this rate case.

b. The deferred taxes related to Tax Goodwill reflected on this schedule are not related to Book Goodwill. The Tax Goodwill reflected relates to certain book assets on the Company's books at the time it was acquired in 2014 for which no tax asset was recorded at the time of acquisition. The largest category of book assets that were on the Company's books that did not have corresponding tax assets relate to pension and post retirement assets/liabilities and associated regulatory assets. At the time of the close of the 2014 transaction the regulated operations of the Company had a net zero opening deferred income tax balance as a result of the Sec. 338(h)(10) election made by the Company and described in its filings associated with the merger approval. The Tax Goodwill reflected on this schedule relates to the amount that was necessary to record at close to offset the amount of book assets recorded that did not have an equal tax basis. The excess deferred taxes related to this Tax Goodwill are not subject to any income tax normalization requirements relative to the pace at which it can be considered for ratemaking purposes and are available to be amortized as the Company and regulatory agency agree.

c. The remaining amortization period is approximately 11.6 years.

d. The company has not prepared this analysis based on its proposed approach for handling excess deferred taxes within this rate case. The excess deferred taxes related to these items are not subject to any income tax normalization requirements relative to the pace at which they can be considered for ratemaking purposes and are available to be amortized as the Company and regulatory agency agree.

e. The amounts labeled "Activity-Regulatory Pre-Grossup" are actually in Column G. These amounts (Column G) represent the change in the balance related to each item based on the change in tax rates that went into effect on January 1, 2018. They were developed as follows:

   For items that are combined (i.e., the same for both Federal and Michigan), the calculation is the cumulative Schedule M difference at December 31, 2017 times 25.74% (new combined rate) minus 38.9% (old combined rate).

   For items that are just Federal, the calculation is the cumulative Schedule M difference at December 31, 2017 times 21% (new Federal rate) minus 35% (old Federal rate).

   For items that are just Michigan, the calculation is the cumulative Schedule M difference at December 31, 2017 times 4.74% (new Michigan effective rate) minus 35% (old Michigan effective rate).

The effect of these adjustments was to restate the deferred tax balances related to each Schedule M to the applicable income tax rates going forward.

f. Column K (End Bal w/o Reg Gross-up) is calculated by taking the Ending Balance (Column I) and adding back Column H (Activity-Regulatory Gross-up). This amount represents the deferred tax balance at 12/31/17 related to this Schedule M at the going forward income tax rates.

g. The company agrees with these amounts (within $200 on each item).

h. The company's proposal is to amortize the aggregate net refundable amount over 5 years as part of this rate case. The net refundable amount is the net of the amounts identified in question g (9,233,660 less 8,942,224 plus 6,027,281) of 6,318,717 (within $100 of amount on spreadsheet of 6,318,807). The company has proposed this approach in order to expeditiously return the excess deferred taxes to its customers under an approach that is less administratively complex than alternative approaches.

i. The pre-existing regulatory assets and liabilities being referred to relate to existing regulatory assets and liabilities at the time of the rate change that were related to previous income tax rate and tax structure changes. Because of the company's acquisition in 2014 and the accounting related to that transaction it does not have material regulatory assets and liabilities related to prior rate and tax structure changes. The re-measurement in worksheet BAW 2-1 relates solely to the 2017 enacted rate change.

Response by: Denise Lepisto, Manager of Accounting

Dated: 2/11/2019

Upper Peninsula Power Company
Case No. U-20276
Electric Rate Case

Auditor: Welke
Date: November 1, 2018
Request No: BAW-2

MPSC Audit Request

BAW_2-3:

RE: Nicholas E. Kates Testimony page 36:

"In addition to the $6.9 million excess deferred tax liability UPPCO has recorded an excess deferred tax asset related Goodwill of $6.7 million." & condition #1 from the order approving settlement agreement from U-17564 "…UPPCo will not seek rate recovery from UPPCo. customers of transaction costs, acquisition premiums goodwill or control premiums or any fees incurred in connection with the proposed transaction."

3. What is the goodwill associated with?

UPPCO Response:

This amount represents Regulated Tax Goodwill. This was created in conjunction with the IRS Sec 338(h)(10) election that was made by UPPCO at the time of its acquisition. Under this election UPPCO established new tax bases for the assets being acquired equal to the consideration that was paid. Within its regulated operations this resulted in creation of a tax goodwill asset related due to certain acquired regulated book assets not being considered assets for income tax purposes. The primary regulated book assets not treated as tax assets were related to various book assets related to UPPCO employee benefit plans (primarily pension and post-employment benefits). The overall effect at the close of the transaction was that the net regulated deferred income tax assets and liabilities netted to zero (i.e., equal amounts of deferred income tax liabilities were established related to book assets not recognized for tax purposes as the deferred income tax assets established related to Regulated Tax Goodwill). This is consistent with how the transaction was described in its filing in U-17564.

This amount is not related to Book Goodwill that was recorded in conjunction with transaction. As described in testimony filed in Case U-17895, ultimately the Book Goodwill created by the accounting for the acquisition was not recorded on UPPCO's books but instead were recorded directly at Upper Peninsula Power Holding Company, UPPCO's parent. As further described in testimony filed in Case U-17895 due the requirements of IRC Sec 338(h)(10) the tax asset created by the book goodwill and transaction costs capitalized was established at UPPCO. This income tax asset was categorized in that filing and this filing as a non-utility balance and excluded from the from the deferred income tax balances reflected in this rate case.

The Regulated Tax Goodwill is unrelated to the book goodwill and capitalized transaction costs, it is a function of the purchase price allocation process required as a result of IRC Sec 338(h)(10) election. All past regulatory filings of UPPCO including Case No. U-17895 and FERC Form 1 filings have reflected the deferred income tax balances related to this item as part of UPPCO's regulated operations.

Response by: Denise Lepisto, Manager of Accounting

Date: 11/12/2018

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
Michigan Attorney General's Third Discovery Request

03-AG-UPPCO-53

Refer to page 35, lines 11-13, of Mr. Kates' direct testimony. Please:

a. Provide the basis for the 5-year amortization period.

b. Explain how the 5-year amortization and refund of protected excess ADIT complies with the ARAM rule. If the Company has an IRS ruling or third party opinion from an authoritative source, please provide it.

UPPCO Response

a. The basis of the 5-year amortization was to offset the rate impacts as originally filed in this case.

b. During the process of preparing the rate case filing UPPCO had discussions with its external auditors regarding its proposed approach. These discussions included representatives from the auditor's national tax practice. During these discussions the schedule detailing the make-up of UPPCO's excess deferred income tax balances by item was reviewed. During those discussions it was agreed that the items on the schedule subject to normalization restrictions were those identified as Depreciation (Plant) and CIAC. The remaining items were subject to UPPCO's discretion relative to how the excess deferred income taxes were handled. The potential to use selected excess deferred tax assets as an offset to the deferred tax liabilities subject to the normalization restrictions such that the net amortization related to that aggregate group was zero was also discussed. The view was that this approach would not create a normalization violation. Based on this view the remaining excess deferred tax liabilities not related to items subject to normalization requirements were determined to be available for amortization as proposed by UPPCO.

Response by: Denise Lepisto, Manager of Accounting

Dated: 2/11/2019

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-7**
Upper Peninsula Power Company **Case No: U-20276**
February 21, 2019
Calculation of Amortization Period for Protected Exess ADFIT **Page 1 of 1**

Line #		2017 Depreciation [1]	
1	Total System		
2	Energy	12,825	
3	Demand	3,403,386	
4	Transmission	-	
5	Distribution - Direct	5,003,408	
6	Distribution - General	2,439,503	
7	Customer	929,396	
8	Total Depreciation	11,788,518	
9			
10		**2017**	
11		**Balance Sheet [2]**	
12			
13	101000 Property In Service Utility	311,274,141	
14	108000 Accumulated Depreciation Utility Plant	(103,429,826)	
15			
16	Net Utility Plant Balance	207,844,314	
17			
18	**Remaining Years to full amortization**	**17.63**	Line 16 / Line 8
19	**Round up to**	**18**	Years

Source: (1) Income Statement Histroical Year Model - Updated DFIT lines 452-459.
(2) Balance Sheet Historical Year Model - Updted DFIT, lines 59 and 63.

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Calculation of Excess Deferred Tax Refundable amounts and Revenue Deficiency Adjustment

Line #	(a)	(b)	(c)	(d)	(e) Total
1	**Protected Excess Deferred Taxes** [1]	$6,857,018	**Non-Protected Excess Deferred Taxes** [1, 2]	$4,475,925	$11,332,943
2	Gross-up Factor	1.3466	Gross-up Factor	1.3466	
3	Refund Liability	$ 9,233,660	Refund Liability	$ 6,027,281	$15,260,941
4	Amortization Period-Years [3]	18	Amortization Period-Years [4]	10	
5	**Annual Refund Amount**	**$ 512,981**	**Annual Amortization**	**$ 602,728**	**$ 1,115,709**
6	Annual Amortization-pre gross-up (L. 1 / L. 4)	$ 380,945		$ 447,593	$ 828,538
7	**Refundable amount for 2018 as a Bill Credit C in 2019**				**$ 1,115,709**
8	**Refunded in Base Rates established in this Rate Case for 2019** and subsequent years				**$ 1,115,709**
9	Refund Amount Included in Revenue Deficiency by UPPCO (938,469 x 1.3466) [5]				$ 1,263,742
10	**Adjustment to increase Revenue Deficiency (Line 9 - Line 5)**				**$ 148,033**

Source:
(1) Exhibit AG-4
(2) Excludes Excess Deferred Taxes related to Goodwill.
(3) Exhibit AG-7
(4) AG Proposal based on reasonable period used by other Michigan utilities.

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
MPSC Staff's
Fourth Discovery Request

4-STAFF-UPPCO-2

Regarding the Company's operating income adjustment on its Exhibit A-13, Schedule C1, line 17, for Interest please provide the following:

a. The underlying mathematical calculation used to compute the $300,000 of interest on a total Company basis.

b. The underlying source documentation for the components used in the mathematical calculation used to compute the $300,000 of interest on a total Company basis.

c. Why is the Company including the $300,000 of interest, on a total Company basis, as a component of its revenue deficiency calculation when general ratemaking dictates that interest is a below the line expense? Below the line meaning not a component of the revenue deficiency calculation.

d. Does the Company agree that the $300,000 of interest, on a total Company basis, should be removed from its derivation of adjusted net operating income on its Exhibit A-13, Schedule C1, line 17? If no, please detail why.

UPPCO Response

a. Not applicable. See answer to "d".
b. Not applicable. See answer to "d".
c. Not applicable. See answer to "d".
d. Yes.

Response by: Gradon R. Haehnel, Director of Regulatory Affairs

Dated: 11/30/2018

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
MPSC Staff's
Fourth Discovery Request

4-STAFF-UPPCO-1

The Company's response to Staff's audit request JSG-1, question 3, confirmed Staff's understanding that the Company included an offset for AFUDC eligible projects included in projected test year CWIP which are accruing AFUDC by including $257,800, on a total Company basis, as an operating income adjustment on its Exhibit A-13, Schedule C1, line 15.

a. It appears the $257,800 on Exhibit A-13, Schedule C1, line 15, as shown, is a reduction to operating income rather than an adjustment to increase operating income. Is this correct?

b. Does the Company agree the adjustment should have been an increase to operating income rather than a decrease in order to appropriately offset the impact of including AFUDC eligible projects in projected test year CWIP as part of the revenue deficiency calculation? If no, please explain why.

UPPCO Response

a. Yes.
b. Yes.

Response by: Denise Lepisto, Manager of Accounting

Dated: 11/30/2018

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Calculation of Adjustment to Working Capital and Deferred Taxes in capital Structure

Line #	(a)	UPPCO Calculation (b)	AG Calculation (c)
1	**Excess Deferred Taxes Liability [1]**		
2	Beginning Balance - 2019 [2]	$ 4,692,345	$ 11,332,943
3	Refund in 2019 [2, 3]	(938,469)	(1,657,076)
4	Ending Balance	3,753,876	9,675,867
5	Average Balance - 2019	4,223,111	10,504,405
6	**Remove from Working Capital - Increase Rate Base**	**$ 4,223,111**	
7	**Amount Added to Deferred Income Taxes in Capital Structure**		**$ 10,504,405**

Source: (1) Before revenue gross-up
(2) UPPCO amount from Exhibit A-13, Schedule C8, line 10 x 5 years.
(3) AG amount from Exhibit AG-8, line 6 x 2 for 2018 and 2019..

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-20276**
Upper Peninsula Power Company | **Exhibit AG-11**
February 21, 2019
Page 1 of 1

Recommended Capital Structure & Cost Rates for
Projected Year Ending December 2019 (Thousands of Dollars)

Line	Description (a)	Note	UPPCO Capital Structure: Capital Balances (b)	% Permenant Capital (c)	% Total Capital (d)	Cost Rate* (e)	Total Cost (d) x (e) (f)	Conversion Factors** (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
1	Long Term Debt	(A)	$ 108,200.0	46.21%	39.58%	4.46%	1.77%	1.0000	1.77%
2	Common Equity	(B)	125,937.0	53.79%	46.07%	9.75%	4.49%	1.3466	6.05%
3	Total Permanent Capital		234,137.0	100.00%	85.66%		6.26%		7.81%
4	Short Term Debt	(A)	7,500.0		2.74%	4.38%	0.12%	1.0000	0.12%
5	Deferred Income Taxes	(C)	31,702.0		11.60%	0.00%	0.00%	1.0000	0.00%
6	JDITC								
7	Long Term Debt	(A)	-		0.00%	4.46%	0.00%	1.0000	0.00%
8	Common Equity	(A)	-		0.00%	9.75%	0.00%	1.3466	0.00%
9	Total JDITC	(A)	-						
10	Capital Structure Adjustment		-		0.00%	7.91%	0.00%	1.0000	0.00%
11	**Total Capitalization & Cost Rates**		$ 273,339.0		100.00%		$\boxed{6.37\%}$		$\boxed{7.93\%}$

Notes

* See Exhibit AG-1***2*** for cost of Common Equity. Cost rates for other capital sources per Company Exhibit A-14, Schedule D-1

** See Company Exhibit A-14, Schedule D1, column (h).

(A) Reflects the capital sources of Upper Peninsula Power per Exhibit A-14, Sched. D1.

(B) Per 1-AG-UPPCO-05, Common Equity at October 31, 2018 was $125.9 Million.

(C) Determined as follows:

	Liability	
Deferred Income Taxes Per Exhibit A-14	$ 12,193	
Adjustments		
Remove Deferred Tax Assets related to Goodwill (Exhibit AG-20)	$ 9,005	
Add Excess Deferred Taxes Liability per AG-10	10,504	
Total Deferred Income Taxes	**$ 31,702**	***To Line 5 Above***

Summary of Cost of Common Equity Analysis

Line	Description (a)	Relative Weighting (b)	Gas Proxy Rates (c)	Note (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	8.42%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	8.75%	2
3	Utility Equity Risk Premium Approach	25.00%	8.75%	3
4	**Sub Total-Calculated Cost of Common Equity (Col. (b) x (c) Summed)**		**8.59%**	
5	**Adjustment to Reflect Non Investment Grade Rating (BBB debt vs BB+ debt)**		**0.60%**	4
6	**Cost of Common Equity to Reflect Higher Risk (line 4 + Line 5)**		**9.19%**	
7	**Cost of Common Equity for Rate Case Purposes**		***9.75%***	5

Note 1 See Exhibit AG-13
Note 2 See Exhibit AG-14
Note 3 See Exhibit AG-15
Note 4 This adjustment reflects the Company's Ba1 rating whereas the peer group is rated in the BBB/Baa category

BBB vs BB debt per P. 12 of McKenzie Testimony (.81% x 66.7%)	0.54%	
UPPCO Short Term Debt Cost Increase	0.62%	
Average	**0.58%**	***USE 0.60%***

Note 5 The additional increase in ROE recommended reflects (a) the fact that UPPCO is somewhat smaller than the peer group; (b) UPPCO's heavier reliance on industrial customer sales; and (c) the potential impact of higher interest rates impacting DCF approach results. In this regard, it should be noted that a 10% correction in electric utility stock prices would have a 0.40% inpact on DCF results.

Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Average 30 Day High Low Price*	Projected 2019 Annual Dividend**	Dividend Yield Col. (d)/c	EPS Growth Rate*** Value Line	Analysts p/Yahoo	Average of Col. (f) & (g)	DCF ROE for Each Co. Col. (e) + (h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Proxy Group								
1	Allete	ALE	$ 78.70	$ 2.34	2.97%	6.30%	7.72%	7.01%	9.98%
2	El Paso Electric	EE	56.32	1.52	2.70%	4.40%	4.12%	4.26%	6.96%
3	IDACORP	IDA	98.69	2.56	2.59%	2.45%	N/M	2.45%	N/M
4	Otter Tail	OTTR	48.09	1.38	2.87%	6.90%	4.76%	5.83%	8.70%
5	PNM	PNM	41.96	1.14	2.72%	4.95%	7.77%	6.36%	9.08%
6	Portland General Electric	POR	47.71	1.52	3.19%	3.75%	4.70%	4.23%	7.41%
7	Unitil	UTL	49.95	1.48	2.96%	N/A	N/M	N/M	N/M
8	**Average of all Companies**				***2.86%***	***4.79%***	***5.81%***	***5.02%***	***8.42%***

* From Workpapers
** The Value Line (VL) Investment Survey Publications of Sep. 14, 2018, Oct. 26, 2018 and VL Small & Mid Cap Publication of Sep. 21, 2018
*** Columns (f) and (g) per workpapers
N/A Not Available
N/M Not Meaningful due to low growth rates

Equation **$R = D/P + g$** *Where* **R** = the required return on the equity security; **D** = the next dividend on the security
P = the current price of the equity security; **g** = the expected growth rate of earnings

Capital Asset Pricing Model Application
(See Equation Below)

Line	Company & Ticker		Mkt. to Bk. Ratio of Com. Equity	Current Beta (B)	Risk Premium (R_p)	Beta x Risk Premium Col. (c) x (d)	2019-20 Risk Free Rate (R_f)	K_e or 2019 CAPM ROE for Each Co. Cols. (e) + (f)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
	Proxy Group							
1	Allete	ALE	1.81	0.70	7.07%	4.95%	4.05%	9.00%
2	El Paso Electric	EE	1.46	0.70	7.07%	4.95%	4.05%	9.00%
3	IDACORP	IDA	2.10	0.60	7.07%	4.24%	4.05%	8.29%
4	Otter Tail	OTTR	2.62	0.80	7.07%	5.66%	4.05%	9.71%
5	PNM	PNM	1.76	0.65	7.07%	4.60%	4.05%	8.65%
6	Portland General Electric	POR	1.63	0.60	7.07%	4.24%	4.05%	8.29%
7	Unitil	UTL	2.19	0.60	7.07%	4.24%	4.05%	8.29%
8	**Average of all Companies**		**1.94**	**0.66**	**7.07%**	**4.70%**	**4.05%**	***8.75%***

Sources

Col. (b) See Exhibit AG-16
Col. (c) The Value Line (VL) Investment Survey Publications of Sep. 14, 2018, Oct. 26, 2018 and VL Small & Mid Cap Publication of Sep. 21, 2018
Col. (d) Reflects the average returns of Large Stocks (11.95%) vs Long Term Gov't Bond Income Returns (5.02%) for the period 1926 to 2017 per the 2018 Ibbotson Clasic Year Book (smaller stock effect addressed in Cost of Equity Summary Exhibit)-AG-WP14-1
Col. (f) Reflects the average 2019-2020 projected yield on 30 Year Treasury Bonds per IHS-Global (see Discovery 1-AG-UPPCO-35)

Equation for CAPM $K_e = R_f + (B \times R_p)$

Where K_e = the Cost of Common Equity; R_f = the Risk Free Rate of Return;
B = the Beta or covariance of the stocks price to overall market ; and
R_p = the Expected Risk Premium of the overall market

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Utility Equity Risk Premium Approach

Line	Description (a)	Peer Group (c)	Note (d)
1	Proxy Group Debt Ratings (S & P)	BBB	1
2	Projected Test Period Risk Free Rate - 30 Year U. S. Treasury Bond Rate	4.05%	2
3	Historical Spread - Electric Utility Common Stocks over A rated Utility Bonds	4.30%	3
4	Sub Total (Line 2 + Line 3)	8.35%	
5	Historical Spread - BBB Bonds vs. A rated bonds	0.40%	4
6	**Cost of Common Equity (Line 4 + Line 5)**	***8.75%***	5

Note 1 Based on Analysis of Ratings From Form 10-K for Peer Companies
Note 2 Reflects the average 2019-2020 projected yield on 30 Year Treasury Bonds per IHS-Global (see Discovery 1-AG-UPPCO-35)
Note 3 See line 39 of Elec. Utility Risk Premium workpaper
Note 4 See Line 24 of page 2 of workpaper covering 30 year Utility Corporate debt Issued.
Note 5 See Cost of Equity Summary Exhibit for adjustments related to Small Company Effect and lower Bond Rating.

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Case No. U-20276
Exhibit AG-16
February 21, 2019

Market to Book Equity Ratios

Line	Company & Ticker		Sept. 2018 Mkt. Price p/ Sh.	Sept. 30, 2018 Book Value of Common Equity ($Mil.)	Sept. 30, 2018 Shares Outstanding (Millions)	Sept. 30, 2018 Book Value Per Sh.	Market to Book Ratio
	(a)		(b)	(c)	(d)	(e)	(f)
	Proxy Group						
1	Allete	ALE	$ 74.60	$ 2,116	51.4	$ 41.17	1.81
2	El Paso Electric	EE	57.32	2,583	65.7	39.32	1.46
3	IDACORP	IDA	98.62	2,368	50.4	46.98	2.10
4	Otter Tail	OTTR	47.85	725	39.7	18.26	2.62
5	PNM	PNM	39.15	1,771	79.7	22.22	1.76
6	Portland General Electric	POR	45.31	2,486	89.2	27.87	1.63
7	Unitil	UTL	50.74	345	14.9	23.15	2.19
12	**Average**						**1.94**

Col. (b) High-Low Average Price Per Yahoo
Col. (c) Per SEC Filings
Col. (d) Per SEC Filings
Col. (e) Equals Col. (c) divided by Col. (d)
Col. (f) Equals Col. (b) divided by Col. (e)

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-20276**
Upper Peninsula Power Company **Exhibit AG-17**
February 21, 2019
Peer Group Capitalization* **Page 1 of 1**

Line	Proxy Group Co	Ticker	Long Term Debt (LTD)	LTD Current Maturities	Total LT Debt	Non-Cntrl or Pref'd	Common Equity	Total	% Common Equity	% LT Debt NC & Pref'd
			As of September 30, 2018 (millions of dollars)							
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Allete	ALE	$ 1,462.0	$ 56.6	$ 1,518.6	$ -	$ 2,116.1	$ 3,634.7	58.2%	41.8%
2	El Paso Electric	EE	1,385.2	-	1,385.2	-	1,197.2	2,582.4	46.4%	53.6%
3	IDACORP	IDA	2,368.1	-	2,368.1	5.4	2,368.1	4,741.6	49.9%	50.1%
4	Otter Tail	OTTR	590.0	0.2	590.2	-	714.6	1,304.8	54.8%	45.2%
5	PNM	PNM	2,142.6	471.9	2,614.5	11.5	1,836.5	4,462.5	41.2%	58.8%
6	Portland General Electric	POR	2,127.0	300.0	2,427.0	-	2,486.0	4,913.0	50.6%	49.4%
7	Unitil	UTL	361.1	31.8	392.9	0.2	345.0	738.1	46.7%	53.3%
9	**Proxy Group Average**								**49.7%**	**50.3%**

* Per individual Company Form 10-K or Form 10-Q filings at September 30, 2018

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Electric Rate Case Return on Equity (ROE) Rates (Jan. 2017-Jun. 2018)
Summary of Results

Line	Number of Rate Orders Issued*	Jan-Dec 2017	Jan-Jun 2018	Total or Average	Source or Reference
1	ROE at 10% or Higher	11	2	13	See Page 2
2	ROE under 10%	29	16	45	See Pages 3 and 4
3	**Total Rate Orders (Lines 1 + 2)**	40	18	58	
4	**Percent Under 10% (Line 2 / Line 3)**	**72.50%**	**88.89%**	**77.59%**	
	Average ROE Assigned				
5	ROE at 10% or Higher	10.31%	10.00%	10.26%	See Page 2
6	ROE under 10%	9.47%	9.53%	**9.49%**	See Pages 3 and 4
7	**Average for all Rate Orders (Lines 5 + 6)**	**9.70%**	**9.58%**	**9.66%**	

Notes
1 Pages 3 and 4 show that companies with ROEs under 10% have had ample access to the Capital Markets

* Per Regulatory Focus as published in January 2018 and July 2018; reflects all published rate case ROEs except for Limited Issue Riders

Electric Rate Case Return on Equity (ROE) Rates (2017-Jun. 2018)

Line	Electric Company	Jurisdiction & Order Date*			Awarded ROE Rate	2017	2018
1	DTE Electric	MI	Jan. 31	2017	10.10%	10.10%	
2	Consumers Energy	MI	Feb. 28	2017	10.10%	10.10%	
3	Arizona Public Service Co	AZ	Aug. 15	2017	10.00%	10.00%	
4	Gulf Power	FL	Apr. 4	2017	10.25%	10.25%	
5	San Diego Gas & Electric	CA	Oct. 26	2017	10.20%	10.20%	
6	Southern California Edison	CA	Oct. 26	2017	10.30%	10.30%	
7	Pacific Gas & Electric	CA	Oct. 26	2017	10.25%	10.25%	
8	Tampa Electric	FL	Nov. 6	2017	10.25%	10.25%	
9	Alaska Electric Light & Power	AK	Nov. 15	2017	11.95%	11.95%	
10	NSTAR Electric	MA	Nov. 30	2017	10.00%	10.00%	
11	W. Mass Electric	MA	Nov. 30	2017	10.00%	10.00%	
12	Consumers Energy	MI	Mar. 29	2018	10.00%		10.00%
13	DTE Electric	MI	Apr. 18	2018	10.00%		10.00%
14	**Average of 13 Decisions**				**10.26%**	**10.31%**	**10.00%**

Analysis By State

Line	State	No. of Decisions	Avg ROE	Comments
15	Alaska	1	11.95%	
16	Arizona	1	10.00%	
17	California	3	10.25%	Wildfire Risks
18	Florida	2	10.25%	Multi Year Agreements with ROE Range of 9.25% to 11.25%
19	Massachusetts	2	10.00%	
20	Sub Total	9		
21	Michigan	4	10.05%	
22	**Total**	13	**10.26%**	

* Per Regulatory Focus as published in January 2018 and July 2018 and reflects all published rate case ROEs except for Limited Issue Riders

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-20276
Upper Peninsula Power Company Exhibit AG-18
February 21, 2019

Electric Rate Case Return on Equity (ROE) Rates Under 10% (2017-Jun. 2018)

Line	Electric Company	Jurisdiction & Order Date*			Awarded ROE Rate	Parent Company	SEC Financials Avail.	Long Term Debt Issued Since Date of Rate Order**
1	MDU Resources	WY	Jan. 18	2017	9.45%	MDU	Yes	$30 M Debt in Q1, 2017-No details
2	Consolidated Edison of NY	NY	Jan. 24	2017	9.00%	Con. Edison	Yes	$700M, 40 Yr. & 10 Yr. Debt in Nov. 2017
3	Delmarva P & L	MD	Feb. 15	2017	9.60%	Exelon	Yes	$200M in first half of 2018
4	Rockland Electric	NJ	Feb. 22	2017	9.60%	Private - $2.5M Revs.	***No***	
5	Tucson Electric Power	AZ	Feb. 24	2017	9.75%	Fortis	***No***	
6	Otter Tail Power	MN	Mar. 2	2017	9.41%	Otter Tail	Yes	$100M, 30 Yr. Debt at 4.07% first half of 2018
7	Oklahoma Gas & Electric	OK	Mar. 20	2017	9.50%	OGE Energy	Yes	$300 M, 30 Yr. Debt at 4.15% in March 2017
8	Liberty Utilities	NH	Apr. 4	2017	9.40%	Algonquin (TSX:AQN)	***No***	
9	Unitil	NH	Apr. 12	2017	9.50%	Unitil (UTL)	Yes	$75M, issued by affiliated companies in Nov. 2017
10	Kansas City Power & Light	MO	Apr. 20	2017	9.50%	Great Plains Energy	Yes	$300M, 30 Yr, May 2017
11	Northern States Power	MN	May 3	2017	9.20%	Xcel Energy	Yes	$100M, 30 Yr, Nov 2017
12	Oklahoma Gas & Electric	AR	May 11	2017	9.50%	OGE Energy	Yes	$300 M, 30 Yr. at 3.85% in August 2017
13	Delmarva P & L	DE	May 18	2017	9.70%	Exelon	Yes	$200M in first half of 2018
14	Idaho Power	ID	May 23	2017	9.50%	IDACORP	Yes	$200M in first half of 2018
15	MDU Resources	ND	Jun. 16	2017	9.65%	MDU	Yes	$240M in first half of 2018
16	Kentucky Utilities	KY	Jun. 22	2017	9.70%	PPL	Yes	$500 M, 30 Yr. at 4.00% in Sept. 2017 (PPL)
17	Louiseville Gas & Electric	KY	Jun. 22	2017	9.70%	PPL	Yes	$500 M, 30 Yr. at 4.00% in Sept. 2017 (PPL)
18	Potomac Electric Power	DC	Jul. 24	2017	9.50%	Exelon	Yes	$100M, 30 Yr. at 4.31% in Nov. 2018
19	Atlantic City Electric	NJ	Sep. 22	2017	9.60%	Exelon	Yes	$350M, 10 Yr. at 4.00% in Oct. 2019
20	Oncor Electric Delivery	TX	Sep. 28	2017	9.80%	Private-Sempra to acquire	Yes	
21	Potomac Electric Power	MD	Oct. 20	2017	9.50%	Exelon	Yes	$100M, 30 Yr. at 4.31% in Nov. 2018
22	Pudget Sound Energy	WA	Dec. 5	2017	9.50%	McQuaire Group	***No***	
23	Ameren - Illinois	IL	Dec. 6	2017	8.40%	Ameren	Yes	$430 M, 30 Yr. at 3.80% in May 2018
24	Commenwealth Edison	IL	Dec. 6	2017	8.40%	Exelon	Yes	$800 M, 30 Yr. at 4.00% in Feb. 2018
25	Northern States Power	WI	Dec. 7	2017	9.80%	Xcel Energy	Yes	$500 M, 10 Yr. at 4.00% in Jun. 2018
26	Southwestern Electric Power	TX	Dec. 14	2017	9.60%	Southwestern Elec. Pwr. (SPS)	Yes	$450 M, 30 Yr. at 3.85% in Jan. 2018
27	El Paso Electric	TX	Dec. 14	2017	9.65%	El Paso Electric	Yes	$190M Debt in first half of 2018
28	Portland General Electric	OR	Dec. 18	2017	9.50%	Portland Gen. Elec.	Yes	
29	Public Service of New Mexico	NM	Dec. 20	2017	9.58%	PNM Resources	Yes	$60M, 10 Yr. Debt in June 2018
30	**Total 2017**				**9.47%**			
31	**Jan - June 2018 (page 4)**				**9.53%**			
32	**Eighteen Month Average**				**9.49%**			

* Per Regulatory Focus as published in January 2018 and reflects all published rate case ROEs except for Limited Issue Riders

** Based on SEC filings

Peer Group Companies — Avg. Peer ROE (pp. 3 & 4) = ***9.48%***

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-20276**

Upper Peninsula Power Company | **Exhibit AG-18**

February 21, 2019

Electric Rate Case Return on Equity (ROE) Rates (Jan - Jun. 2018)

Line	Electric Company	Jurisdiction & Order Date*			Awarded ROE Rate	Parent Company	SEC Financials Avail.	Long Term Debt Issued Since Date of Rate Order**
1	Kentucky Power Company	KY	Jan. 18	2018	9.70%	American Elec. Power	Yes	$500M in May 2018
2	Public Service of Oklahoma	OK	Jan. 31	2018	9.30%	American Elec. Power	Yes	$500M in May 2019
3	Interstate Power & Light	IA	Feb. 15	2018	9.98%	Interstate Pwr. & Lgt. (IPL_pd)	***No***	
4	Duke Energy Progress	NC	Feb. 23	2018	9.90%	Duke	Yes	$989M in first in 2nd Qtr of 2018
5	Allete - Minnesota Power	MN	Mar. 12	2018	9.25%	Allete	Yes	$60M, 30 Yr. Debt at 4.07% in Apr. 2018
6	Niagra Mohawk Power	NY	Mar. 15	2018	9.00%	National Grid PLC	Yes	$701M in 2nd Qtr of 2018
7	Indiana Michigan Power	MI	Apr. 12	2018	9.90%	American Elec. Power	Yes	$600M, 10 Yr. Debt in Nov. 2018
8	Duke Energy Kentucky	KY	Apr. 13	2018	9.73%	Duke	Yes	$500M in May 2018
9	Conn. Light & Power	CT	Apr. 18	2018	9.25%	Eversource	Yes	
10	Avista	WA	Apr. 26	2018	9.50%	Avista	Yes	$375M, 30 Yr. in May 2018
11	Indiana Michigan Power	IN	May 30	2018	9.95%	American Elec. Power	Yes	$600M, 10 Yr. Debt in Nov. 2018
12	Patomac Electric Power	MD	May 31	2018	9.50%	Exelon	Yes	$100M, 30 Yr. at 4.31% in Nov. 2018
13	Central Hudson Gas & Elec.	NY	Jun. 14	2018	8.80%	Fortis	***No***	
14	Duke Energy Carolinas	NC	Jun. 22	2018	9.90%	Duke	Yes	
15	Emera Maine	ME	Jun. 28	2018	9.35%	EMERA (EMA)	Yes	
16	Hawaii Electric Light	HI	Jun. 29	2018	9.50%	Hawaiian Electric	Yes	
17	**Jan - June 2018 (page 3)**				**9.53%**			

* Per Regulatory Focus as published in July 2018; reflects all published rate case ROEs except for Limited Issue Riders

** Based on SEC filings

Peer Group Companies

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
the Attorney General's
First Discovery Request

1-AG-UPPCO-05

Please provide the Company's Common Equity balances for each month end from January through October 2018 similar to Exhibit A-4 (NEK-4), Schedule D5.

UPPCO Response

Please see Attachment 1-AG-UPPCO-5 7 and 9.xlsm

Response by: Denise Lepisto, Manager of Accounting

Dated: 12/11/2018

Attachment to 1-AG-UPPCO-5, 7 & 9

	Adjusted Common Equity
Jan-18	(125,448,814.24)
Feb-18	(126,225,933.06)
Mar-18	(126,008,477.29)
Apr-18	(126,260,024.94)
May-18	(124,845,043.68)
Jun-18	(124,923,484.55)
Jul-18	(126,476,929.44)
Aug-18	(126,376,202.22)
Sep-18	(125,542,160.26)
Oct-18	(125,936,756.50)

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
the Attorney General's
Fourth Discovery Request

4-AG-UPPCO-64

Refer to the response to 27-Staff-UPPCO-4.

a. The question in subpart (a) asked if the Company had issued any debt since 9/16/14. The response states no new long-term debt as of 9/16/2016. Should the response have said that no new long-term debt has been issued since 9/16/014? If not, answer the question as it was posed and explain what increases occurred and when.

b. With regard to the response to subpart (b):

   i. Explain what prevents Company management from articulating a clear strategy for financing the Company's capital structure.

   ii. Explain what scenarios and possibilities are being contemplated and when those decisions will be made.

   iii. Explain what you mean by pushing down 100% of equity from UPPHCO, particularly when UPPHCO has $101 million of equity capital and UPPCO supposedly has $154 million of equity capital.

c. With regard to subpart (c) and (d), does the Company plan to undertake an analysis of the benefits and drawbacks of raising debt at UPPCO instead of the holding company, as perhaps a way to lower the cost of debt, any time soon? If yes, provide an approximate timeframe. If no, why not?

d. Is the debt at UPPHCO directly secured by the assets of UPPCO? If yes, explain the arrangement. If no, what security is pledged to UPPHCO debt holders?

UPPCO Response

a. Yes.

b.

   i. UPPCO is in the final stages of completing its 2019 financing plan. At present, UPPCO does not anticipate or foresee the need for any additional debt or equity capital.

ii. See response to 4-AG-UPPCO-64b(i), above

iii. As a clarification, UPPCO original filing assumed that any incremental push down of capital from UPPHCO would be 100% equity. Per UPPCO's revised 2019 financing plan, UPPCO no longer intends to push down capital in any form from UPPHCO to UPPCO.

c. In alignment with UPPCO's revised 2019 financing plan, UPPCO believes that there is no need for incremental financing.

d. All debt is raised at the UPPHCO level, with some capacity for additional debt allowed for issuance directly by UPPCO. UPPHCO's post-closing capital structure would be maintained so as to allow it to access the capital markets. Furthermore, UPPHCO's parent is interested in placing equity capital in regulated utilities such as UPPCO, and UPPCO will therefore have sufficient access to equity to meet its future operational needs, as necessary. Therefore, consistent with the foregoing, and based on a cursory review of the debt market documents and subject to the other related debt documents, including the intercreditor agreement, the Collateral (as defined therein) includes the pledged interests of UPPCO through UPPHCO.

Response by: Nicholas E. Kates, CFO
Dated: February 7, 2019

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
Michigan Attorney General's Third Discovery Request

03-AG-UPPCO-45

Refer to Exhibit A-4 (NEK-4), Schedule D1 and Exhibit A-14 (NEK-8), Schedule D1, please provide detailed schedules of the Schedule M component items and related Deferred Income Taxes that make up the amounts of $17,156,488 and $12,192,745. Provide also a reconciliation of the changes in these amounts. Provide this information in Excel.

UPPCO Response

The amounts in the exhibits represent 13-month average balances. Please see 3-AG-UPPCO-45_Attachment_a for the calculation of the historical test year Schedule M item detail. Please see 3-AG-UPPCO-45_Attachment_b for the calculation of the projected test year Schedule M detail.

Response by: Denise Lepisto, Manager of Accounting

Dated: 2/11/2019

TOTAL Deferred Taxes Balance Report								MPSC Case No. U-20276			
								3-AG-UPPCO-45_Attachment_a			
2017 UPPCO Actuals											
Upper Peninsula Power Co.											
ACROSS OPERATING INDICATORS											
All Current Year, Rate Change and RTP Activity											
		Schedule M Items					Deferred Taxes				
M Item		"Beginning Balance"	"Current Activity"	"True-Up Activity"	"Adjustment Activity"	"Ending Balance"	"Beginning Balance"	"Current Activity"	"True-Up Activity"	"Adjustment Activity"	"Ending Balance"
FTNOT0	Bad Debts	$1,000,000.00	$730,000.00	$0.00	$0.00	$1,730,000.00	$389,000.00	$154,602.91	$0.00	($177,215.19)	$366,387.72
FTNOV0	Charitable Contributions	$234,138.33	$78,425.87	$0.00	$110.00	$312,674.20	$91,079.82	$20,172.34	$0.00	($30,769.82)	$80,482.34
FTPD70	CIAC (P-I-S) Fed	$1,324,604.65	$55,923.36	$0.00	$0.00	$1,380,528.01	$463,611.65	$9,030.13	$0.00	($249,723.49)	$222,918.29
STPD70	CIAC (P-I-S) MI	$1,324,604.65	$55,923.36	$0.00	$0.00	$1,380,528.01	$51,659.60	$2,813.60	$0.00	$14,983.40	$69,456.60
FTNO90	Customer Advances	$1,972,579.08	($55,997.17)	$0.00	$0.00	$1,916,581.91	$767,333.28	($11,859.36)	($0.01)	($349,570.96)	$405,902.95
FTNET0	Def Compensation	$73,963.76	$121,192.43	$0.00	$0.00	$195,156.19	$28,771.91	$25,666.72	($0.02)	($13,107.50)	$41,331.11
FTNOA0	Def Inc & Deduct Cur	($7,304,931.21)	$44,242.50	$0.00	$0.00	($7,260,688.71)	($2,841,618.23)	$9,369.88	($0.02)	$1,294,544.80	($1,537,703.57)
FTPD70	Depreciation (Plant)	($23,408,379.98)	($12,782,701.31)	($12,837,812.00)	($691,397.00)	($49,720,290.29)	($8,192,933.00)	($1,928,676.94)	($4,493,234.20)	$6,763,968.63	($7,850,875.51)
STPD70	Depreciation (Plant) (MI)	($16,210,264.76)	($7,478,159.33)	($12,755,897.82)	($233,031.00)	($36,677,352.91)	($632,200.33)	($379,156.11)	($497,480.04)	($347,430.33)	($1,856,266.81)
FPPDD0	Depreciation (Plant)-Perm	($138,106.54)	$0.00	$0.00	$0.00	($138,106.54)	($79,111.77)	$0.00	$0.00	$40,056.60	($39,055.17)
SPPDD0	Depreciation (Plant)-Perm MI	($138,106.54)	$0.00	$0.00	$0.00	($138,106.54)	($8,815.31)	$0.00	$0.00	($0.01)	($8,815.32)
FTNOD0	Environmental Cleanup	($838,920.52)	$74,192.28	$0.00	$0.00	($764,728.24)	($326,340.08)	$15,712.80	$0.01	$148,669.46	($161,957.81)
FTPD71	Future Proposed Adjustments (Fed)	($512,662.38)	$0.00	$1,361,657.00	$5,010,156.00	$5,859,150.62	($179,431.83)	($944,548.66)	$476,579.95	$1,593,496.36	$946,095.82
STPD71	Future Proposed Adjustments (MI)	($512,662.38)	$0.00	$1,361,657.00	$5,010,156.00	$5,859,150.62	($19,993.84)	$56,672.92	$53,104.64	$204,999.58	$294,783.30
FTPD70	Goodwill	$131,141,694.93	($10,421,748.69)	($106.31)	($106.00)	$120,719,733.93	$45,899,593.25	($1,977,157.60)	($37.19)	($21,019,937.72)	$22,902,460.74
STPD70	Goodwill (MI)	$131,141,694.93	($10,421,748.00)	($106.31)	($106.00)	$120,719,734.62	$5,114,526.10	($506,674.53)	($4.16)	$1,261,190.79	$5,869,038.20
FTNOH0	Interest	($878,473.59)	$479,288.92	$0.00	$0.00	($399,184.67)	($341,726.23)	$101,506.11	($0.01)	$155,678.88	($84,541.25)
FTNOB0	Net Operating Loss - Fed	$26,552,606.00	$3,734,475.99	$11,456,198.31	($4,348,731.00)	$37,394,549.30	$9,293,412.09	$1,685,584.71	$4,009,669.40	($7,838,904.82)	$7,149,761.38
STNOB0	Net Operating Loss - MI	$19,354,491.16	($1,570,067.25)	$11,374,284.31	($4,807,097.00)	$24,351,611.22	$754,825.16	($149,151.94)	$443,597.07	$109,518.89	$1,158,789.18
FTNEB0	Pension	($58,667,770.00)	$1,241,366.00	$0.00	$0.00	($57,426,404.00)	($22,821,762.53)	$262,902.48	$0.00	$10,396,820.00	($12,162,040.05)
FTNEF0	Pension Restoration	$156,027.00	$19,537.00	$0.00	$0.00	$175,564.00	$60,694.50	$4,137.64	$0.00	($27,650.36)	$37,181.78
FTNEL0	Pension Restoration - Current	$28,849.00	($20.00)	$0.00	$0.00	$28,829.00	$11,222.26	($4.24)	$0.00	($5,112.49)	$6,105.53
FTNEA0	Post Retirement - Med/Dental	$1,387,424.00	($99,851.36)	$0.00	$0.00	$1,287,572.64	$539,707.94	($21,147.01)	$0.00	($245,872.61)	$272,688.32
FTNEL0	Post Retirement - Med/Dental - Current	$24,093.00	$0.00	$0.00	$0.00	$24,093.00	$9,372.19	$0.00	$0.00	($4,269.65)	$5,102.54
FTNED0	Post Retirement Life	$485,608.00	$106,502.24	$0.00	$0.00	$592,110.24	$188,901.49	$22,555.55	$0.00	($86,057.10)	$125,399.94
FTNOM0	Price Risk Hedging (NonCur-Asset)	$187,802.13	($170,279.97)	$0.00	$0.00	$17,522.16	$73,055.04	($36,062.71)	$0.00	($33,281.40)	$3,710.93
FTNOO0	Reg Asset ST	($55,000.00)	$0.00	$0.00	$0.00	($55,000.00)	($21,395.00)	$0.00	$0.00	$9,746.84	($11,648.16)
FTNON0	Reg Asset ST Offset	$55,000.00	$0.00	$0.00	$0.00	$55,000.00	$21,395.00	$0.00	$0.00	($9,746.84)	$11,648.16
FTNOO0	Reg Assets (Current)	($407,030.14)	$4,882,836.51	$0.00	$0.00	$4,475,806.37	($158,334.75)	$1,034,110.76	$0.01	$72,131.92	$947,907.94
FTNON0	Reg Assets (Non-Current)	($28,975.00)	$0.00	$0.00	$0.00	($28,975.00)	($11,271.27)	$0.00	$0.00	$5,134.81	($6,136.46)
FTNOQ0	Reg Liab ST	$187,801.66	($170,279.97)	$0.00	$0.00	$17,521.69	$73,054.85	($36,062.71)	$0.00	($33,281.32)	$3,710.82
FTNOP0	Reg Liab ST Offset	($187,801.66)	$170,279.97	$0.00	$0.00	($17,521.69)	($73,054.85)	$36,062.71	$0.00	$33,281.32	($3,710.82)
FTNOP0	Reg Liabilities-Non-Cur	$877,105.68	($110,907.56)	$0.00	$0.00	$766,198.12	$341,194.13	($23,488.54)	$0.00	($155,436.45)	$162,269.14
FTNOO0	Regulatory Asset-Auto Current-DNU	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	($0.01)	$0.00
FTNEP0	Restricted Stock	$119,204.33	($24,865.07)	$0.00	$0.00	$94,339.26	$46,370.49	($5,266.03)	$0.00	($21,124.83)	$19,979.63
FTNEE0	SERP	$19,759.00	($751.00)	$0.00	$0.00	$19,008.00	$7,686.25	($159.05)	$0.00	($3,501.60)	$4,025.60
FTNEE0	SERP - Current	$27,004.00	($4,780.00)	$0.00	$0.00	$22,224.00	$10,504.56	($1,012.32)	$0.00	($4,785.54)	$4,706.70
FTNEL0	Sick Leave - Current	$41,370.00	($859.00)	$0.00	$0.00	$40,511.00	$16,092.93	($181.93)	$0.00	($7,331.38)	$8,579.62
Total For Upper Peninsula Power Co.:		$208,428,340.59	($31,518,829.25)	($40,125.82)	($60,046.00)	$176,809,339.52	$28,545,075.47	($2,579,708.42)	($7,804.56)	($8,559,889.14)	$17,397,673.35
Rpt # Tax A	2/8/2019 13:57										

TOTAL Deferred Taxes Balance Report									MPSC Case No. U-20276		
									3-AG-UPPCO-45_Attachment_b		
Roll Fwd of UPPCO 2018 Rate Case											
Upper Peninsula Power Co.											
Electric											
All Current Year Activity											
		Schedule M Items					Deferred Taxes				
M Item		"Beginning Balance"	"Current Activity"	"True-Up Activity"	"Adjust ment Activity"	"Ending Balance"	"Beginning Balance"	"Current Activity"	"True-Up Activity"	"Adjust ment Activity"	"Ending Balance"
FTNOT0	Bad Debts	$2,000,000.00	$0.00	$0.00	$0.00	$2,000,000.00	$435,885.72	$0.00	$0.00	$0.00	$435,885.72
FTPD70	CIAC (P-I-S) Fed	$1,435,528.01	$55,000.00	$0.00	$0.00	$1,490,528.01	$234,468.29	$11,550.00	$0.00	$0.00	$246,018.29
STPD70	CIAC (P-I-S) MI	$1,435,528.01	$55,000.00	$0.00	$0.00	$1,490,528.01	$72,063.60	$2,607.00	$0.00	$0.00	$74,670.60
FTNO90	Customer Advances	$2,099,999.91	($69,713.00)	$0.00	$0.00	$2,030,286.91	$453,114.74	($17,944.13)	$0.00	$0.00	$435,170.61
FTNET0	Def Compensation	$129,669.19	($129,669.00)	$0.00	$0.00	$0.19	$24,474.76	($33,376.80)	$0.00	$0.00	($8,902.04)
FTNOA0	Def Inc & Deduct Cur	($7,110,877.71)	$277,500.00	$0.00	$0.00	($6,833,377.71)	($1,499,142.22)	$71,428.50	$0.00	$0.00	($1,427,713.72)
FTPD70	Depreciation (Plant)	($55,622,869.02)	($6,667,503.00)	$0.00	$0.00	($62,290,372.02)	($9,123,968.31)	($1,400,175.63)	$0.00	$0.00	($10,524,143.94)
STPD70	Depreciation (Plant) (MI)	($44,515,826.36)	($7,797,503.00)	$0.00	$0.00	($52,313,329.36)	($2,227,131.95)	($369,601.64)	$0.00	$0.00	($2,596,733.59)
FTNOD0	Environmental Cleanup	($699,854.24)	$75,000.00	$0.00	$0.00	($624,854.24)	($145,259.25)	$19,305.00	$0.00	$0.00	($125,954.25)
FTPD71	Future Proposed Adjustments (Fed)	$848,994.62	$0.00	$0.00	$0.00	$848,994.62	$137,089.88	$0.00	$0.00	$0.00	$137,089.88
STPD71	Future Proposed Adjustments (MI)	$848,994.62	$0.00	$0.00	$0.00	$848,994.62	$42,714.30	$0.00	$0.00	$0.00	$42,714.30
FTPD70	Goodwill	$46,104,187.73	($4,356,249.00)	$0.00	$0.00	$41,747,938.73	$7,233,196.02	($914,812.29)	$0.00	$0.00	$6,318,383.73
STPD70	Goodwill (MI)	$46,104,188.46	($4,356,249.00)	$0.00	$0.00	$41,747,939.46	$2,332,259.53	($206,486.22)	$0.00	$0.00	$2,125,773.31
FTNOH0	Interest	$0.33	$0.00	$0.00	$0.00	$0.33	$18,208.97	$0.00	$0.00	$0.00	$18,208.97
FTNOB0	Net Operating Loss - Fed	$13,093,233.74	$2,758,757.00	$0.00	$0.00	$15,851,990.74	$1,845,495.69	$579,338.97	$0.00	$0.00	$2,424,834.66
STNOB0	Net Operating Loss - MI	$1,986,189.95	$3,888,757.00	$0.00	$0.00	$5,874,946.95	$112,155.06	$184,327.08	$0.00	$0.00	$296,482.14
FTNEB0	Pension	($56,486,666.00)	$877,212.00	$0.00	$0.00	($55,609,454.00)	($11,920,151.49)	$225,794.37	$0.00	$0.00	($11,694,357.12)
FTNEF0	Pension Restoration	$221,490.00	$55,365.00	$0.00	$0.00	$276,855.00	$49,003.14	$14,250.96	$0.00	$0.00	$63,254.10
FTNEL0	Pension Restoration - Current	$28,829.00	$0.00	$0.00	$0.00	$28,829.00	$6,105.53	$0.00	$0.00	$0.00	$6,105.53
FTNEA0	Post Retirement - Med/Dental	$1,032,317.64	($241,996.00)	$0.00	$0.00	$790,321.64	$206,985.69	($62,289.77)	$0.00	$0.00	$144,695.92
FTNEL0	Post Retirement - Med/Dental - Current	$24,093.00	$0.00	$0.00	$0.00	$24,093.00	$5,102.54	$0.00	$0.00	$0.00	$5,102.54
FTNED0	Post Retirement Life	$713,432.24	$120,872.00	$0.00	$0.00	$834,304.24	$156,628.22	$31,112.46	$0.00	$0.00	$187,740.68
FTNOM0	Price Risk Hedging (NonCur-Asset)	$0.16	$0.00	$0.00	$0.00	$0.16	($799.23)	$0.00	$0.00	$0.00	($799.23)
FTNOO0	Reg Assets (Current)	$1,197,911.37	($1,197,911.00)	$0.00	$0.00	$0.37	$104,177.77	($308,342.29)	$0.00	$0.00	($204,164.52)
FTNON0	Reg Assets (Non-Current)	($28,975.00)	$0.00	$0.00	$0.00	($28,975.00)	($6,136.46)	$0.00	$0.00	$0.00	($6,136.46)
FTNOQ0	Reg Liab ST	$17,521.69	$0.00	$0.00	$0.00	$17,521.69	$3,710.82	$0.00	$0.00	$0.00	$3,710.82
FTNOP0	Reg Liab ST Offset	($17,521.69)	$0.00	$0.00	$0.00	($17,521.69)	($3,710.82)	$0.00	$0.00	$0.00	($3,710.82)
FTNOP0	Reg Liabilities-Non-Cur	$1,526,459.12	$816,932.00	$0.00	$0.00	$2,343,391.12	$357,960.33	$210,278.29	$0.00	$0.00	$568,238.62
FTNEP0	Restricted Stock	$74,906.26	($43,796.00)	$0.00	$0.00	$31,110.26	$14,977.57	($11,273.09)	$0.00	$0.00	$3,704.48
FTNEE0	SERP	$3,158.00	($20,987.00)	$0.00	$0.00	($17,829.00)	($54.19)	($5,402.05)	$0.00	$0.00	($5,456.24)
FTNEE0	SERP - Current	$22,224.00	$0.00	$0.00	$0.00	$22,224.00	$4,706.70	$0.00	$0.00	$0.00	$4,706.70
FTNEL0	Sick Leave - Current	$40,511.00	$0.00	$0.00	$0.00	$40,511.00	$8,579.62	$0.00	$0.00	$0.00	$8,579.62
Total For Upper Peninsula Power Co.:		($43,493,221.97)	($15,901,181.00)	$0.00	$0.00	($59,394,402.97)	($11,067,289.43)	($1,979,711.28)	$0.00	$0.00	($13,047,000.71)
Rpt # Tax Accru	2/8/2019 13:53										
	Total Goodwill - Deferred Taxes Post TCJA						$9,565,456				$8,444,157
	Average amount of Goodwill- Deferred Income Taxes in Capital Structure										$ 9,004,806

Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company's Responses to
MPSC Staff's
Thirteenth Discovery Request

13-STAFF-UPPCO-2

Please provide justification for the Capital Structure Adjustment found on Exhibit A-14 Schedule D1.

UPPCO Response

Capital Structure Adjustment accounts found on Exhibit A-14, Schedule D1:

Account	Description	13-Month Avg
174950	Self Implemented Rate Refund	42,885
235000	Customer Deposits	(176)
143240	A/R ATC O&M	175,751
182330	Reg Asset Def Tax	87,927
		306,387

- 174950 – This is the over-refunded amount from the U-18220 Self Implemented Rate Refund.
- 235000 – Customer deposits as security for the payment of bills.
- 143240 – Accounts receivable for ATC O&M work paid by ATC.
- 182330 – Last activity was in 2016. This account was not in the U-17895 rate case.

Response by: Denise Lepisto, Manager of Accounting

Dated: 11/30/2018